Access Arrangement Information for 1 July 2012 to 30 June 2017

September 2011

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Executive summary

Meeting the Access Code objective

This is Western Power's second submission of revisions to the access arrangement and associated regulatory review by the Economic Regulation Authority (the Authority). The proposed revisions will apply to the five years from 1 July 2012 to 30 June 2017. This is referred to as the AA3 period as it will be covered by the third iteration of the access arrangement.

This access arrangement revisions submission has been developed in accordance with the *Electricity Networks Access Code 2004* (Access Code). The submission draws on the experience and lessons learned from previous regulatory periods (AA1 and AA2) and details our proposal to:

- invest in the network to improve safety and security of supply while providing sufficient capacity to meet state growth
- maintain existing good quality service levels to the million customers connected to our network
- refine incentive arrangements to deliver service improvements specifically where they are valued by customers, and to strengthen Western Power's incentives to minimise costs

We consider that the revisions and investment proposal detailed in this submission best support the Access Code objective, which is to:

> *promote the economically efficient:*
>
> *a) investment in; and*
>
> *b) operation and use of*
>
> *networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.*

*Note: All monetary amounts presented in this document are expressed in **real 30 June 2012 dollars** unless otherwise stated. Some tables may not add due to rounding.*

Introduction

AA3 represents a pivotal period for Western Power. Five years on from disaggregation, the business is reaching a level of maturity more reflective of a commercial and customer-oriented organisation. Improvements in efficiency and governance processes, greater understanding of the unique challenges of economic regulation and recognition of the value of working more closely with our stakeholders, are enabling us to perform more effectively in our relatively new regulatory landscape.

The proposed revisions detailed in this access arrangement information draw on the experience and lessons learned from previous regulatory periods and build on the foundations laid since disaggregation in 2006.

The network itself is reaching a definitive point in its life cycle. As the state emerges from its brief economic hiatus during the global financial crisis, rising peak energy demand is increasing pressure on a network that has endured unsustainably low levels of investment in asset replacement. AA3 represents a period when the network's ability to endure can no longer be taken for granted.

This means that investment for the coming regulatory period will be significantly greater than during the preceding five years. This increased investment will inevitably result in a higher network tariff, which contributes about half the final electricity cost to customers.

We propose that now is the most efficient time to deliver this investment. The cost of delivering this work in the future will be much greater as asset condition deteriorates and network risk rises.

We understand that customers are feeling the pinch as energy prices increase. Costs have risen across the entire energy supply chain in recent years and the network tariff is the one component of the overall price increase that we can influence. When developing our AA3 proposal we have balanced the need for essential network investment with a program that does not increase network tariffs unnecessarily. Over the longer term, investing today will mean lesser and more sustainable price impacts for customers in the future.

We are vigorously pursuing new and innovative ways of managing peak demand. During AA3 we will modernise and renew the asset population, making the network safer, more secure and setting a foundation for efficient investment and sustainable performance levels over the next decade.

We also have a unique opportunity during AA3 to move towards a ‘smart’ future. There are 280,000 non-compliant electricity meters that *must* be replaced during the period. In this submission we are seizing this chance to test the benefits of smart technology and replace these obsolete assets with smart meters and supporting communications. In Western Australia we have been prudent in taking a watching brief on smart grid developments in other states; we now have an opportunity to make more than one third of our meter population ‘smart’. This is an advantage we would be unwise to forsake.

Essentially, AA3 is a platform for building a sustainable future. While the investment proposal has been shaped by 50 years of previous investment, it is important to remember that the decisions we make now will impact the next 50 years. Efficient network investment during AA3 will bring the system to a level that will resolve the immediate network challenges before the major issues become insurmountable. Most importantly, it will ensure customers can continue to enjoy a level of service that they value.

Our AA3 revision proposal

Our proposal builds on previous access arrangement revisions and seeks to improve the current network asset condition. The investment program focuses on three key service outcomes:

	This...	**...not this**
1. Safety	Address the highest priority public safety risks	Set unrealistic expectations that all public safety risks will be immediately resolved
2. Growth & security	Expand the network’s capacity to meet growth and connect new customers Address the network’s sub-optimal resilience to widespread outages	Over-invest to provide excess capacity and eliminate all outages
3. Service	Maintain current average service levels, improving service only where it is valued by the customer and efficient to do so	Improve service regardless of whether it is valued by the customer and efficient to do so

These outcomes balance customer expectations and network risk with efficient delivery and price impact.

Our aim is to efficiently minimise costs over successive access arrangements. The investment program proposed for AA3 is part of a long-term network planning horizon. Essentially, choosing the right investment to deliver these service outcomes during AA3 will enable continued efficient investment in AA4 and beyond.

The package of proposed revisions to the access arrangement for the AA3 period comprises:

- total investment of $8.523 billion over the five-year AA3 period, compared to $6.544 billion over the five-year period 2007/8 to 2011/12
- an initial network tariff real increase of 16.4% and then approximately 11% for each subsequent year of AA3
- a rate of return on investment that enables Western Power to earn a reasonable return necessary to attract financial capital in a constrained capital environment and commensurate with the commercial risks of providing services
- a higher-powered incentive framework that increases the incentive for Western Power to achieve cost efficiencies and maintains the pressure of providing service at levels that customers value
- improvements to the economic efficiency of key policies including the applications and queuing policy and contributions policy
- a revenue requirement of $10.329 billion over the period to ensure all of these proposed investments and service outcomes can be delivered to our customers

The package of proposed revisions will:

- reduce public safety risk associated with asset failure
- provide sufficient network capacity to facilitate ongoing growth and improve system security that will decrease the likelihood of long-duration or widespread outages
- prevent deterioration of service, maintaining it at a level consistent with the historical average over the last five years.

We consider that the proposed revisions satisfy the requirements of the Access Code.

When developing the revisions, we conducted a series of stakeholder engagements to capture our customers' requirements and help us provide services during AA3 that reflect their immediate and long-term needs.

Key forecasts of growth, peak demand, cost of capital and input cost escalation are all founded on independent expert advice. Proposed revisions have also been informed by regulatory precedent and the experiences of other network businesses.

What will be delivered – the investment proposal and outcomes to customers

The investment proposal for AA3 focuses on addressing the underlying risk in the Western Power Network[1]. While customers have continued to enjoy a good level of service, risks relating to safety, growth and security have steadily grown as the network has aged and pressure from rising demand has increased.

This is the heart of our challenge. Safety, growth and security are aspects of performance that are less conspicuous to customers than appreciable measures such as reliability or power quality. Often customers will only perceive safety, growth or security as an issue when a safety incident occurs, they are not able to connect, or they experience long-duration outages. We must not allow the network to degrade to a point where customers are frequently experiencing these types of incidents.

[1] The Western Power Network is defined by the *Electricity Networks Access Code 2004* as *the portion of the South West Interconnected Network (SWIN) that is owned by the Electricity Networks Corporation* (Western Power).

This means that while customers may not perceive an improvement in safety, security or the network's ability to meet growth, they would experience significant service degradation if we did not invest.

The Western Power Network was constructed largely in the 1960s and 70s. This initial asset investment was followed by an extended period of investment targeted at meeting the needs of our growing state by connecting new customers and generators.

We are now at a time when many assets are reaching the end of their serviceable lives. The network has performed admirably over the past decades, operating effectively despite only a subsistence level of investment in asset replacement. Many of the ageing assets must be replaced if we are to prevent current service performance and network risk from deteriorating to a level that it would be economically inefficient to recover from.

The declining asset condition drives a need for increased capital investment in AA3 compared to previous regulatory periods. We can no longer delay the inevitable.

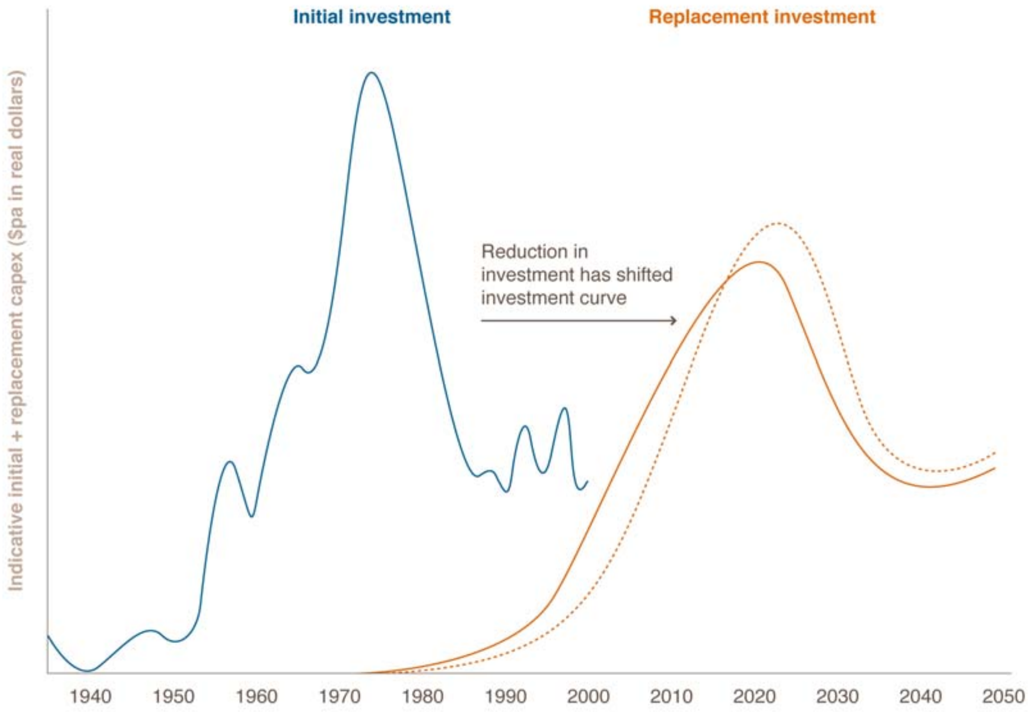

Figure 1: Projected trend of investment to replace network assets and impact of deferring investment[2]

Figure 1 shows the trend of historical investment in the Western Power Network and the optimal path for replacing assets. The dotted line shows how the investment path for replacement will shift if investment is postponed further, increasing the cost to customers. Allied to replacing existing assets, ongoing growth in demand drives the need to augment the network with new assets. During AA3 we have an opportunity to derive efficiencies from delivering augmentations and asset replacement together. However, when investing in network capacity we will not rely solely on 'more of the same' investments. We will continue to investigate emerging technology that can improve the effectiveness of demand-side management and 'smart' energy solutions.

[2] Note that this chart is indicative only and does not represent actual replacement costs.

Capital investment

Capital investment during AA3 is forecast to be $5.810 billion compared with $4.468 billion during the preceding five-year period (2007/8 to 2011/12).

The capital investment forecast considers regulatory obligations and is founded on our network investment strategy, our network development plan and network management plan, which incorporate growth and demand forecasts and asset condition. The forecast has been assessed to ensure service outcomes are delivered at the lowest sustainable cost. We have also undertaken detailed analysis to ensure that the scale and scope of works can be delivered efficiently and effectively over the AA3 period.

Figure 2 shows how the proposed capital investment for AA3 compares with previous access arrangement periods.

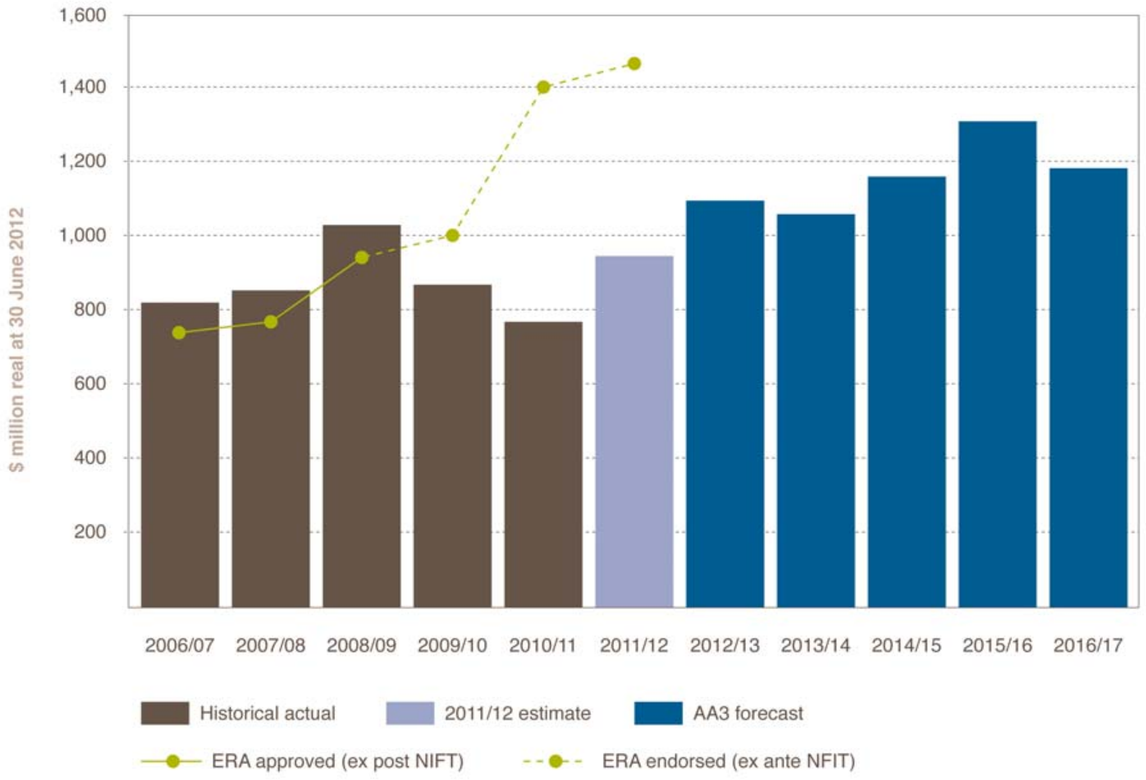

Figure 2: Forecast and historical capital expenditure

As previously mentioned, governance improvements made over the course of AA1 and AA2 will allow the business to efficiently deliver the AA3 program in full and in line with forecast.

During AA2 our governance review included reconsideration of our requirements and increased discipline on our investment decisions. As a result, several major projects scheduled for the AA2 period were reprioritised or deferred. It was this governance review, combined with a reduction in customer-driven work and a tightening of State capital investment, which contributed to the lower level of capital investment during the AA2 period than was originally forecast and endorsed by the Economic Regulation Authority (the Authority).

This renewed governance rigour and lessons learned from the AA2 period means that the forecast capital investment for AA3 is robust and deliverable.

We are confident that the investment during AA2 was appropriate and that the AA3 capital investment also represents an economically efficient program of works that will provide sustainable services to new and existing customers.

Figure 3 provides a breakdown of forecast capital investment by category.

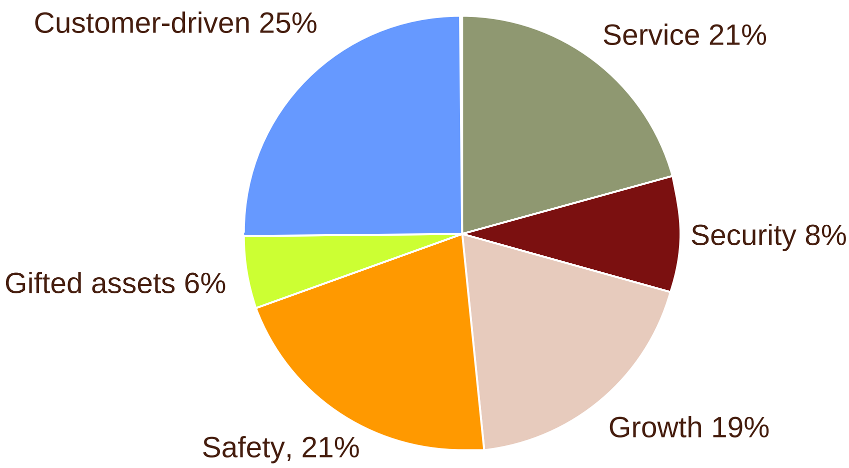

Figure 3: Forecast capital investment for the AA3 period

Investing in public safety

We own and operate a vast electrical network that impacts the general community. Our infrastructure crosses both public and private property, above and below ground. While an inherent risk exists in any electrical network, we have a responsibility to properly manage public safety risks associated with our assets.

During AA3 we will invest **$1.222 billion** of capital in four key public safety programs to decrease the potential for public safety incidents in the network. This is 21% of the total capital investment for AA3.

The greatest risk to public safety posed by the network is the potential for assets to initiate fires and cause electric shock.

Four key programs of work that will focus on these issues during AA3 are:

- bushfire mitigation
- pole management
- replacing obsolete overhead customer service connections
- conductor management

While safety performance will always be hugely contingent on external factors such as adverse weather, our aim is to achieve as much as we can to eliminate the factors that are within our control such as ensuring our assets are in good condition.

These four key programs will have the greatest effect on reducing the likelihood of major public safety incidents and can feasibly be delivered during the period.

Delivery of the safety investment program in full will improve the condition of our pole population and satisfy safety regulatory obligations. Most importantly, this investment will minimise further physical degradation of the network and reduce the likelihood of major public safety incidents.

The estimated impact of these investment programs is to:

- reduce the likelihood of electric shocks caused by assets
- reduce the likelihood of asset-initiated fires[3]

Pole management and bushfire mitigation

The inherent risk of electricity providing a source of ignition, coupled with Western Australia's hot, dry summer climate means that there is the potential for bushfires, some of which may be attributed to network assets.

There are 176,000 wood poles located in 'extreme' or 'high' bushfire risk areas. A failed wood pole presents multiple hazards. The pole itself can harm people or damage property and energised power lines contacting the ground could cause electric shock or, in very specific conditions, start fires.

Our objective is to replace or reinforce any unsafe pole before it falls. However, this will take time.

Wood poles are usually serviceable for 40 to 50 years. More than 200,000 of Western Power's 630,000 wood poles are over 40 years old. The overall condition of the pole population is such that Western Power's pole failure rate is the highest in Australia by a significant margin.

We therefore propose to increase pole replacement and reinforcement rates during the AA3 period. The plan is to replace or reinforce an average of 33,000 poles per year at a total cost of $748 million. This is a 70% increase on the AA2 program which in turn was double the AA1 program. The program will be prioritised to address the poles in the poorest condition and in the highest risk locations first.

Based on the current assessment of the condition of the wood pole population, it will take 20 years of elevated investment before we are able to replace or reinforce poles at the same rate that they are identified to need replacing or reinforcing[4]. As shown in Figure 4, we have considered more aggressive investment profiles. However, we believe the 20-year wood pole management plan is the most achievable approach to improving the overall condition of the wood pole population in line with our regulatory obligations.

[3] As the occurrence of a fire is heavily dependent on weather conditions, it is not possible to accurately predict the number of fires that will occur during AA3. However the proposed investment will reduce the likelihood that these fires will be caused by asset failure.

[4] This is referred to as the 'sustainable rate' of replacement.

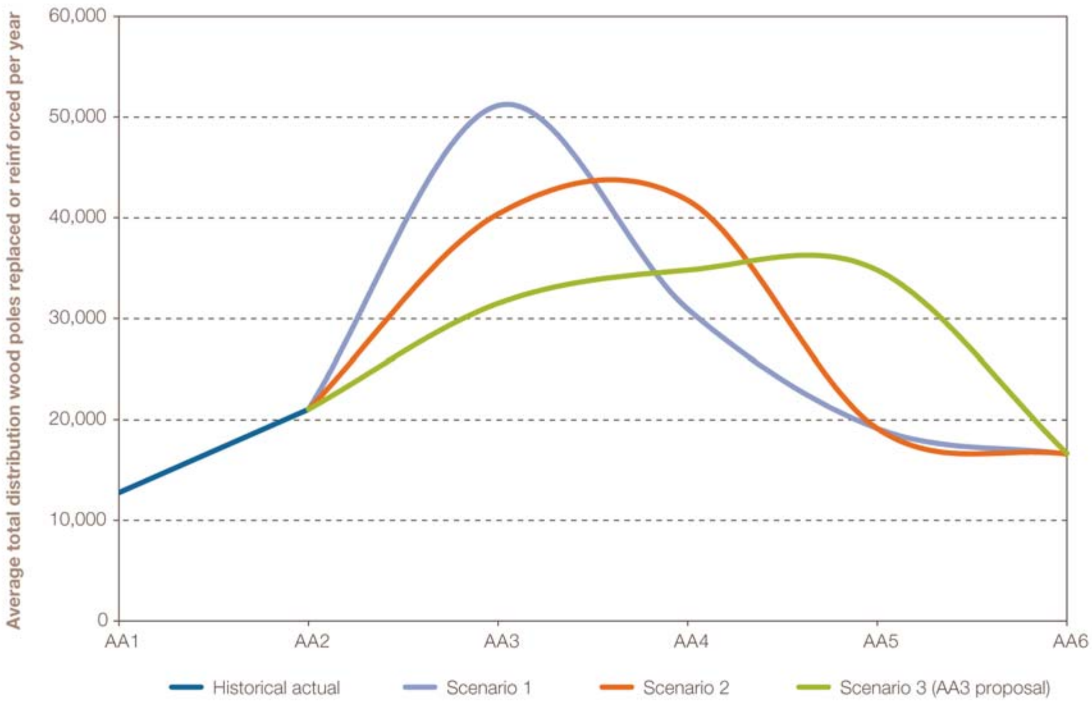

Figure 4: Comparison of paths to achieving a sustainable rate of wood pole replacement over 5, 10 or 20 years

We also propose an increase in specific bushfire mitigation activities such as vegetation management and pole top replacement. Investment in bushfire mitigation activities in AA2 was $34 million in capital expenditure and $34 million in operating expenditure per year and was targeted in extreme and high bushfire risk areas. This program is maturing during AA3 with a forecast investment of $45 million annual capital expenditure and $42 million annual operating expenditure.

Overhead customer service connections and conductor management

At the end of AA1 there were 272,000 obsolete overhead customer service connections in the Western Power Network. Historically these connections, which link customers' homes to the distribution network, are responsible for an average of 80% of the total electric shocks attributed to our assets each year.

By the end of AA2 we will have replaced more than 100,000 of these potentially dangerous connections and will ramp-up the program in AA3 to replace the balance by the end of 2015/16. This average annual expenditure will be $17 million in the five years of AA3 compared to $25 million during the three years of AA2.

The network also contains 53,650 km of overhead power lines. All overhead electricity networks carry an inherent public safety risk due to the potential for power lines to fall or clash due to equipment failure, extreme weather or other external factors. During AA3 we will replace 1,073 km of power lines in the poorest condition to reduce this risk.

Growth and security of supply

Western Australia continues to grow. Despite deferral of a number of large load and generation projects as a result of the global financial crisis, our economy is expanding at a stable rate.[5] Accordingly, electricity demand has risen, with peak demand increasing on average by 147 MW per year over the last decade. We forecast a similar rate of increase will continue throughout AA3, leading to peak demand greater than 5000 MW by the end of the AA3 period, as shown in Forecast and historical increase in system peak demand.

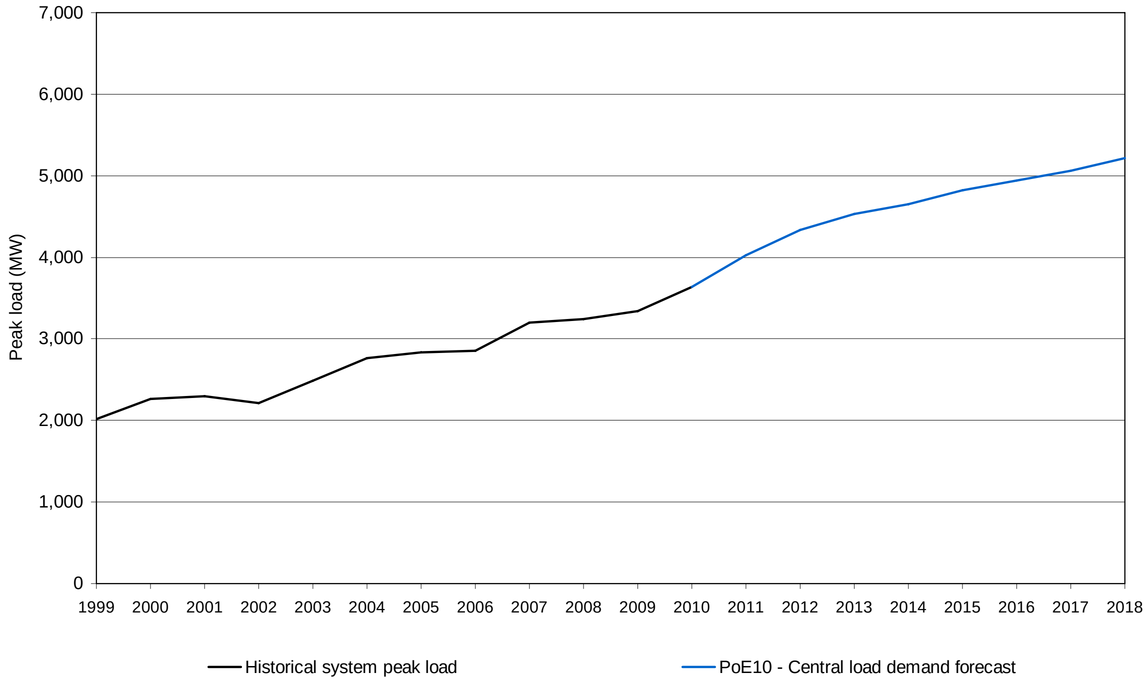

Figure 5: Forecast and historical increase in system peak demand

Accommodating this annual growth in peak demand while maintaining current network adequacy and security levels will require investment to expand the capacity of the network. The average cost of this is approximately $675 million per year.

During AA1, Western Power was able to keep pace with growth through a program of efficient capacity expansion. AA2, however, presented a dramatically different challenge for the business.

The economic down-turn, combined with an internal governance review, prompted the business to revisit its plans and reprioritise the works program to ensure we could meet long-term growth. This led to the postponement of specific capacity expansion projects and the use of reserve network capacity to keep pace with the steady increase in electricity demand.

While this strategy enabled customers to continue to connect to the network during AA2, it means that by the end of the period there will be very little reserve capacity left that would allow the network to continue functioning effectively in the wake of an outage event. As a result this approach is not sustainable for AA3.

Our program for AA3 is based on the least-cost approach to meeting long term growth in the state, balanced against what can physically be delivered during the period given process approval constraints (for example environmental and regulatory approvals).

[5] p23, 'Economic Outlook', *Budget 2011-2012 Budget Overview*, Government of Western Australia, May 2011.

Forecast capital investment in growth and security is **$3.374 billion**, compared to $2.759 billion invested in the preceding five-year period. This increase investment comprises $2.885 of growth related capital expenditure, of which $1.782[6] billion is customer-driven and is therefore non-discretionary. The investment also incorporates $0.489 billion required to address security risks in the network.

While the increase in growth and security-related investment is substantial, the implications of not delivering this work during AA3 are significant. A lower level of investment may lead to restrictions on the number of customers that can connect to the network, potentially inhibiting economic growth. The worst-case scenario would be system collapse with a similar outcome to the five-hour blackout that occurred in 1994. An equivalent collapse is estimated to have a $350 million impact on the Western Australian community if it occurred today.

The combined effect of security and growth projects is to:

- meet a system peak demand of 5061 MW by the end of AA3
- enable secure connection of an estimated 130,000 new customers
- reduce the number of metropolitan customers at risk of long duration outages (longer than 5 hours) due to insufficient distribution transfer capacity by 420,000 by the end of AA3
- return the number of customers at risk of supply interruptions due to single outages of transmission infrastructure to 100,000 by the end of AA3
- reduce the number of metropolitan distribution feeders that are loaded above 80%[7] from 236 to 0 by the end of AA3, thereby significantly reducing the number of customers at risk from prolonged outages
- reduce the number of country customers at risk of potential equipment damage due to being supplied from voltage constrained feeders by 70% by the end of AA3
- enable secure connection of proposed new large generators in the mid-west, which is not currently possible

Facilitating growth

We will invest $2.885 billion in growth-related capital during the AA3 period. Capacity expansion is a key driver of this investment, for example the Mid West Energy Project, which involves constructing a new 330 kV transmission line from Perth to Eneabba, contributes $244 million to this total alone.

This is a significant increase in capacity expansion investment compared to that incurred during AA2. However, this increase in investment is necessary to restore reserve capacity depleted during the period. Continuing capacity expansion at AA2 levels of investment is not sustainable from a network risk perspective and would result in significantly degraded outcomes for customers.[8]

The majority of growth-related investment in AA3 is driven by customer connections. Work required to respond to the needs of residential, commercial, industrial and generating customers is forecast to increase, resulting in 130,000 new loads by the end of the AA3 period.

[6] Including $321 million of gifted assets.
[7] The level of interconnection of distribution feeders in the Perth Metropolitan area allows a target utilisation of 80% which is higher than the national benchmark level of 66%.
[8] The Technical Rules also requires Western Power to maintain a level of reserve capacity. Technical Rule no. 2.5.4.3 requires Western Power to design distribution feeders so that capacity can be transferred as a result of an unplanned outage.

As previously mentioned, customer-driven investment accounts for $1.782 billion (53%) of growth-related capital expenditure during the period. Of this investment, we anticipate $0.914 billion will be covered by direct contributions from customers.

Customer-driven transmission works are subject to fluctuations in customer needs and timeframes. During the AA2 period, the global financial crisis caused the number of new transmission connection applications to drop below AA1 levels in 2009/10, before picking up in 2010/11. We now have a record number of major load and generator connection applications. In the case of significant differences in actual growth-related investment compared to forecast, the arrangements we had in place during AA2 to ensure customers only pay for growth investment that actually occurs will continue into AA3. This will be managed through the investment adjustment mechanism.

It is important to recognise that due to the requirements of the *Electricity Industry (Obligation to Connect) Regulations 2005*[9] and the requirement for electricity generators to have unconstrained generation dispatch, customer-driven work is non-discretionary.

Improving network security and reducing system overloads

System security is achieved by building a level of reserve capacity into the system to allow it to continually supply customers in the event of an unplanned outage.

As previously described, deferral of investment in capacity expansion during the AA2 period led to much of the reserve capacity in the network being used to connect new customers and facilitate new growth. In AA3 we will ensure network security by building sufficient reserve capacity back into the network.

The Australian benchmark for maximum individual distribution feeder utilisation is 66%. This was re-confirmed[10] following a catastrophic event in Queensland in 2004 which resulted in widespread outages and significant economic loss. A root cause was identified as overly aggressive utilisation of distribution feeders (76%).

There are currently 420,000 customers supplied by distribution feeders at greater than 80% utilisation and therefore at risk of long-duration[11] outages caused by feeder failure. The proposed investment will significantly reduce this risk by the end of AA3 and remove the large gap between Western Power and the good electricity industry practice of most other network businesses in the eastern states.

Maintaining service levels

In AA3, the focus is to *maintain* average historical service levels throughout the period, improving service only where it is required and efficient to do so.

Maintaining service levels also includes continuing compliance with a number of statutes that cover all aspects of planning, developing and managing the electricity network. As new and improved standards are implemented, failure to upgrade the network will result in non-compliance with regulations to ensure public safety or maintain service quality.

Failure to invest in these programs will:

- increase our legal and operational liability for non-compliance with various legislative requirements

[9] See Section 4 ‘Obligation to attach or connect premises’, *Electricity Industry (Obligation to Connect) Regulations 2005*.
[10] *Report on Electricity Distribution and Service Delivery for the 21st Century* (Somerville Report), 2004.
[11] Longer than 5 hours.

- lead to an increase in public and operator safety risks
- lead to an increasing gap between our practices and recognised prudent asset management practices
- progressively reduce reliability
- progressively increase operating (maintenance) expenditure, which is an inefficient use of resources

The proposed capital investment on maintaining service levels and compliance is **$1.214 billion**[12], which equates to 21% of the AA3 capital investment proposal.

The proposed investment related to maintaining current average service performance and compliance is focused on replacing unserviceable transmission and distribution assets (in addition to the pole replacement program). This includes replacing 280,000 non-compliant three-phase electricity meters to ensure we comply with legal obligations such as the *Metering Code*[13].

In some cases, there is a risk that additional investment will be required. For example, ongoing discussions with the Environmental Protection Agency may result in an additional $270 million of expenditure if Western Power is required to comply with new noise regulations relating to distribution assets.

It is important to note that while we are proposing to maintain service and compliance levels for AA3, the cost of achieving this will be greater than in AA2. This is due to asset age, declining asset condition and loading.

The decision to maintain current service levels rather than further invest in improving service is based on two key factors. First, a series of customer engagements and survey of customer preferences[14] conducted in October 2010 provided evidence that the majority of Western Power customers are satisfied with current average service levels.[15]

Secondly, the proposed service performance incentive scheme for AA3 will adequately drive investment in service performance. This means there is no requirement to include the specific costs of improving average performance in the tariff to all customers.

Service experience is not uniform across the network. Electricity supply is more reliable in metropolitan areas than in rural and edge-of-grid areas. Delivering improvements in rural and edge-of-grid areas costs significantly more per capita than in metropolitan areas and is often financially prohibitive. However, our proposed changes to the incentive regime will provide an increased incentive to deliver improvements in rural and edge-of-grid areas where it is efficient to do so.

Essentially, the rewards for improving (and penalties for decreasing) service will be adjusted so that they reflect the value that customers place upon them. Typically, the financial incentive rate for improving service in rural and edge-of-grid areas will be greater than in metropolitan areas.[16]

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[12] Including $301 million corporate costs.
[13] *Electricity Industry Metering Code 2005.*
[14] The KPMG survey engaged more than 600 residents and small businesses to determine their preferred level of reliability.
[15] Customers in rural areas, where reliability performance is often poorer than metropolitan areas, were an exception to this rule and indicated they would prefer service improvements. However the cost of delivering improvements in rural areas is difficult to justify under the current regulatory arrangement.
[16] Comparison based on comparing a rural area with predominantly agricultural load to a metropolitan residential load.

Despite the increased financial incentive, the high cost of delivering improvements in some edge-of-grid areas may still not be economically justifiable under Western Power's economic regulatory regime. In such cases, additional support from Government may be required.

We believe our approach to maintaining average service levels and only investing in improvement where it is valued is more efficient and fairer for all customers.

Operating expenditure

Operating expenditure during AA3 is forecast at $2.714 billion, compared with $2.077 billion over the preceding five-year period (2007/8 to 2011/12).

Despite the required increase in capital investment for AA3, our governance and process improvements achieved during the AA2 period has improved our ability to operate the at more economically efficient levels.

The governance review conducted during AA2 enabled the business to achieve significant efficiencies, particularly relating to delivery of the works program. More robust planning and business case development, improved procurement practices and revised contractual arrangements with delivery partners contributed to lower-than- forecast operating expenditure. This in turn has created a strong platform for ensuring expenditure during the AA3 period continues to be economically efficient.

Figure 6 shows the proposed operating expenditure compared to previous access arrangement periods.

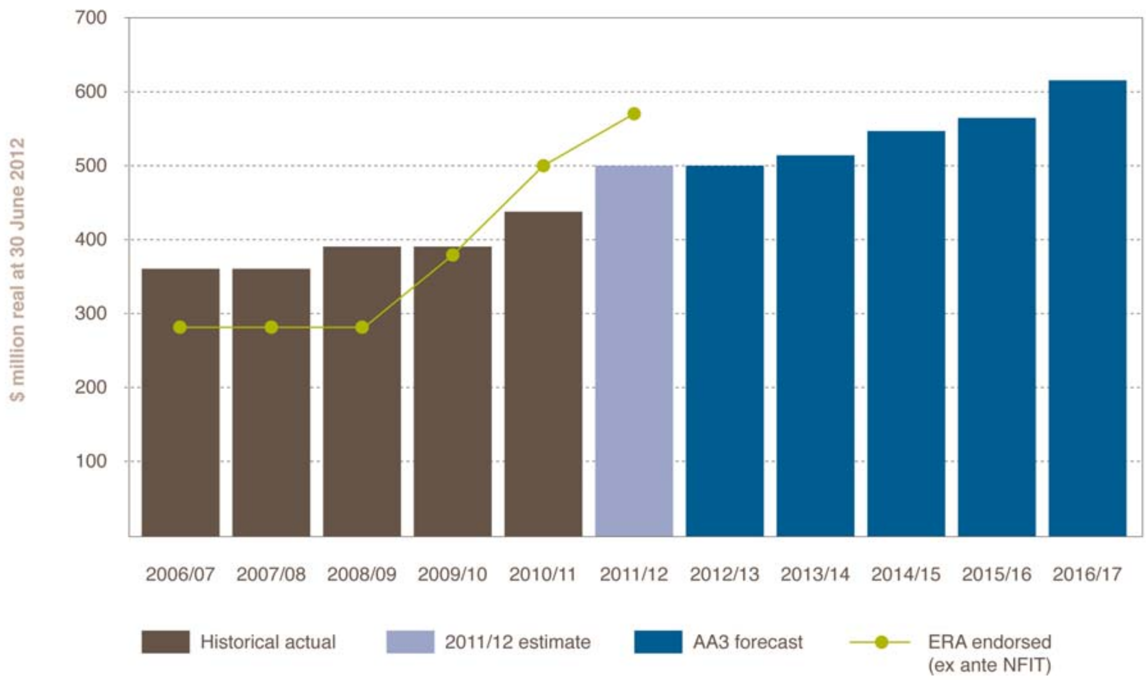

Figure 6: Forecast and historical operating expenditure

The operating expenditure forecast is based on adjusting the efficient base year for expected cost drivers. This includes applying an adjustment for forecast movements in the market costs of labour and materials, and specific adjustments of other foreseeable costs. We have also made an adjustment for costs associated with growth in the size of the network and customer base.

The forecast reflects the efficient costs of providing services because it is based on our revealed efficient costs given the operational improvements we have implemented during AA2. The forecasts also compare favourably with historical trends and those of our peers.

Why the investment proposal will be delivered

Improvements to governance activities during the AA2 period, founded on a review of historical performance, mean that we are confident the AA3 investment proposal will be delivered.

We recognise that the level of proposed investment for AA3 is greater than in the preceding five years. We have assessed our ability to leverage domestic and global resources to effectively manage the labour and material requirements and we believe we have the capability to deliver the work. We have also mapped AA3 requirements against the resourcing levels available to our delivery partners.

We are working closely with key stakeholders, particularly the Department of Treasury to ensure they have visibility of the investment program and financial impacts. This continued engagement will improve access to funding when the investment is required.

The proposed refinements to the incentive regime will also increase the incentive to deliver prescribed services to expected standards and achieve operating cost efficiencies.

In summary, the following factors ensure we can and will deliver the proposed investment:

- ***network risk dictates that this investment must be undertaken*** – our network cannot sustain the safety and security risk of not delivering this investment program. We are committed to key programs for lowering bushfire risks, addressing legal obligations and completing existing asset compliance-improvement programs
- ***Western Power has a flexible and efficient delivery strategy*** – our delivery strategy will ensure we efficiently minimise the cost of delivery through a balanced portfolio of internally and externally delivered works. The flexibility of the balanced portfolio allows resources to be ramped-up efficiently to deliver large projects and respond to customer needs
- ***higher-powered incentives will drive efficient investment*** – the amended service incentives will strengthen the penalty for not delivering service outcomes. It will also increase our incentive to efficiently minimise costs by increasing the likelihood of eligibility for additional rewards
- ***key Government stakeholders have visibility of funding requirements*** – we have worked in conjunction with our financier (the Department of Treasury), the Department of Finance, Department of the Premier and Cabinet and the Office of Energy to improve their understanding of the level of funding required for the AA3 investment proposal

What it will cost – the regulatory proposal

To deliver the service outcomes outlined in the investment proposal, we require target revenue of $10.329 billion during AA3.

The AA3 target revenue includes $0.967 billion in revenue required to cover costs in AA2 that was deferred from AA2 to minimise price impacts during that period. Further, almost $1 billion of the total AA3 target revenue is the tariff equalisation contribution (TEC) that Western Power is required by Government to pay to subsidise Horizon Power. The TEC has increased by $0.258 billion compared to the preceding five-year period.

We propose that all costs are recovered during the AA3 period.

Hon Martin Ferguson, Federal Minister for Resources and Energy in a 2011 speech to CEDA said "*there is no quick fix to artificially hold electricity prices below where they need to be to maintain reliability. Tempting as it may be, suppressing prices through regulation or market barriers creates even more pain in the longer term by delivering inefficient investment outcomes which, in turn, will either mean higher bills for consumers or reduced reliability.*"[17]

We endorse this view and are mindful of our contribution to the total price to customers. We propose that an initial larger-than-average increase followed by lesser increases in succeeding years will best manage the long term price impacts on customers. As a result, the recommended price path is a CPI+16.4% increase in the first year of AA3, followed by a CPI+11.1% to 11.5% increase in each of the four following years, as shown in Figure 7.

We believe this is preferable to a glide path of larger price increases, as it will continue the relatively high tariff increases of AA2 *for one year only* before lessening the impact thereafter.

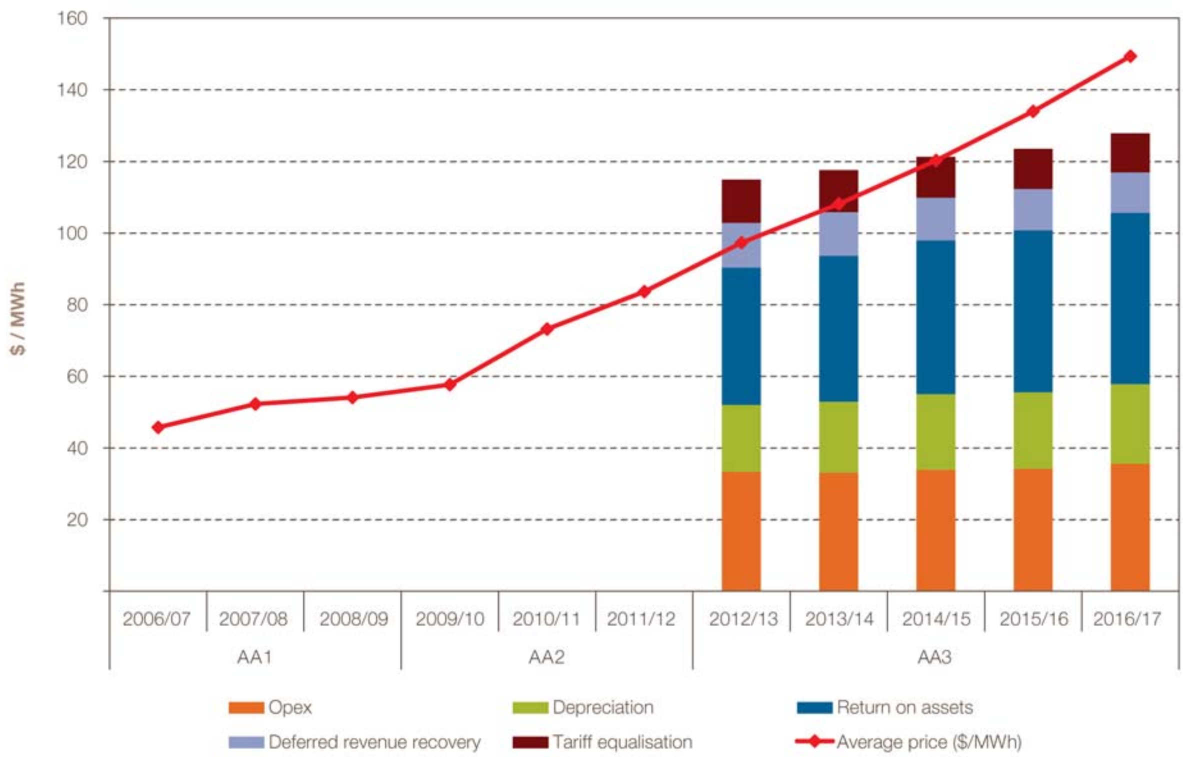

Figure 7: Forecast and historical average price path

Network tariff increases will directly affect customers that have contestable supplies. This is approximately 1.8% (18,500) of our customer base, consisting primarily of major industrial,

[17] The Hon Martin Ferguson AM MP, Minister for Resources and Energy and Minister for Tourism, speaking at Committee for the Economic Development of Australia (CEDA), Sydney, 4 May 2011.

commercial and energy industry customers. The network tariff represents between 20-40%[18] of retail prices paid by these customers.

The retail tariff that is paid by residential and small business customers (non-contestable customers) will be determined by Government energy policy settings.

Capital base

A key driver of the target revenue is the capital base and return thereon. We have calculated our opening capital base for AA3 as $7.098 billion by rolling forward the existing capital base.

Consistent with the method followed by the Authority in the AA2 review, this calculation involved adding $2.635 billion we invested in our network during AA2 and $244 million in speculative investment from AA1. We then deducted asset disposals, forecast depreciation and customer contributions. The capital base has been escalated for actual inflation.

The investment requirement for AA3 means that by the end of the period the capital base is forecast to increase to $10.415 billion.

Cost of capital

Electricity networks are capital-intensive businesses. Western Power, like any corporation, must recover a return on investment that reflects a commercial rate of compensation sufficient to attract funds to the business and enable it to compete with alternative investments with equivalent risk. A reasonable return is necessary if capital investment is to remain sustainable in future periods. Failure to provide a commercial rate of return, calculated as the weighted average cost of capital (WACC), will constrain our access to funds and therefore impact investment.

We estimate a pre-tax WACC of 8.82%. This has been derived using independent expert advice[19] on our risk position and what a commensurate return for a business with our risk profile would be. The proposal is also informed by regulatory precedent, with reference to recent decisions by the Australian Energy Regulator and Australian Competition Tribunal rulings on eastern-state networks and the latest round of WA regulatory determinations by the Authority.

The 8.82% figure is consistent with the Access Code, which allows Western Power the opportunity to earn target revenue consistent with an '*amount that meets the forward-looking and efficient cost of providing covered services, including a return on investment commensurate with the commercial risks involved*'[20].

Services, service standards and incentives

During AA3 we will provide 17 reference services. These include the same 14 reference services provided in AA2, with an adjustment to the existing bi-directional service and the addition of three new bi-directional reference services in response to growing demand for photovoltaic systems.

As Western Power is a natural monopoly, the regulatory regime provides a series of incentive mechanisms designed to replicate market pressures that would otherwise drive

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[18] The proportion of the retail price for contestable customers that constitutes the network tariff varies according to whether the customer is on an energy-based or demand-based tariff.

[19] Prof. Stephen Gray, PhD BCom (Hons) LLB (Hons), Professor of Finance at University of Queensland provided expert advice on the equity beta parameter of the WACC. Professor Gray is a renowned expert on WACC parameters, having provided advice to other Australian utilities and is a technical expert for the Australian Competition Tribunal.

[20] Section 6.4(a)(i), *Electricity Networks Access Code 2004.*

service performance and cost outcomes. Drawing on AA2 experiences and our customer-survey results, we propose enhancements to the AA2 service standards and incentive mechanisms that will ensure we have a greater incentive to increase efficiency, but will be penalised if we let service performance fall below the expected level. We believe that this will better meet the Access Code objective and improve the customer experience in terms of cost and service over time.

We publicly report on more than 200 measures to enable our customers and key stakeholders to monitor our performance and compare it against our history and our peers. A key part of the arrangement that supports service performance is the setting of service standard benchmarks and the targets that will be included in the financial incentive scheme - the service standards adjustment mechanism (SSAM).

The service standard benchmarks are to be set at a level that most of our customers will receive most of the time. This will ensure that we remain compliant with our licence and receive any additional rewards for cost efficiencies under the gain sharing mechanism. The targets under the SSAM will be set at the level of service we expect to provide at least 50% of the time. The financial rewards and penalties for improvements or degradation in service are also to increase. This will strengthen the incentive to maintain and improve service above expected levels (where efficient to do so).

We consider that this combination of strong incentives to achieve cost efficiencies and maintain service levels will ensure we achieve both.

We have reviewed the service standard benchmarks to ensure that they represent service standards relevant to our reference services. As a result we have revised the suite of service standard benchmarks, adding two new customer-service measures relating to call centre performance and account management for transmission-connected customers.

We have also removed any measures that are duplicated or relate to network performance rather than measures of service to customers. Importantly, the measures that have been removed from the suite of minimum standards will still be publicly reported, allowing our customers to continue to assess our performance in these areas.

These arrangements mean that service improvements will be delivered only where the value to customers is greater than the cost of delivering them. Also, because benefits received under the SSAM are awarded in the following regulatory period, customers will not pay for service improvements until AA4.

The enhanced service standards and incentive regime, with its balanced service and efficiency incentives, provides greater assurance that Western Power’s AA3 investment proposal will be delivered efficiently, without compromising service.

Why this package of revisions is the most suitable for the AA3 period

In developing this package of proposed revisions we have considered our customers’ expectations and the growing needs of the state. We have balanced this against risk, cost and practical deliverability.

The result is an AA3 proposal that efficiently addresses legacy issues while maintaining service and reducing risk.

Our risk management approach to asset management and works planning is cognisant of the consequences of alternative investment profiles to that proposed for AA3. These consequences show either an intolerable risk for the network or greater costs to customers.

- If Western Power was to *improve* average service performance and had the capacity to address *all* public safety risks during the period, the investment proposal would result in substantially higher network tariff increases.
- If Western Power was to invest less in public safety programs, the risks would increase unacceptably and may increase the potential for Western Power to be non-compliant.
- If Western Power was to invest less in facilitating growth and restoring security, outcomes to customers would put state development and economic growth at risk.
- If Western Power was to invest less in maintaining service, the impact on Western Power's ability to provide covered services and maintain compliance would be at risk.

Conclusion

This package of revisions to our access arrangement is the best and most balanced proposal for the AA3 period. The service outcomes that will be delivered effectively balance customer expectations and network risk with price impacts and efficient delivery.

In summary, these proposed revisions are the right ones because they:

- comply with the Access Code
- give our customers what they value within the constraints of what is deliverable
- address the highest priority public safety risks
- reduce long-term degradation of the network
- ensure we continue to operate our business efficiently
- secure the long term interests of customers by ensuring we are viable and able to meet our customers' ongoing demands

As part of a long-term strategy, AA3 will consolidate the service improvements delivered during the first two access arrangement periods. The access arrangement revisions will enable Western Power to bring the network to a sustainable level of performance and security, laying the platform for efficient improvements and added customer value in AA4 and beyond.

PART A: BACKGROUND AND CONTEXT

1 Structure of this submission

This chapter outlines the structure of the access arrangement information, its relationship to the access arrangement and how it was developed. It provides:

- an overview of the key regulations and codes that inform the access arrangement information
- a summary of the document structure and information contained in each section
- a summary of the approach Western Power adopted and its key considerations when developing the proposed revisions to the access arrangement

1.1 Key messages

- The proposed revisions apply to the period 1 July 2012 to 30 June 2017 (five year period).
- We propose the access arrangement revisions submission date for AA4 is 1 March 2016 (15 months prior to the end of the AA3 period) to allow sufficient time to complete the process prior to the commencement of the AA4 period.
- The structure and content of the document is informed by the Economic Regulation Authority's *Guidelines for Access Arrangement Information (herein referred to as the AAI Guidelines)*, which was published on 6 December 2010.
- The revisions are guided by compliance with specific criteria and the objectives of the *Electricity Networks Access Code 2004* (herein referred to as the Access Code).
- We have engaged key stakeholders including major customers, government agencies, peak representative bodies and local government to help shape the proposed revisions.
- We have conducted a thorough review of past performance and focused on identified areas of weakness to look at how we improve these and build on progress made during AA2.
- Through monitoring experiences in other jurisdictions we have identified opportunities to adopt practices that may enhance outcomes to our customers under the WA regulatory framework.
- The Authority is required to approve a proposed access arrangement if the proposed access arrangement satisfies the Access Code objective and the requirements of chapter 5 and chapter 9 of the Access Code.

1.2 Access Code provisions

In accordance with section 4.48 of the Access Code this document comprises the access arrangement information for consideration by the Authority as part of Western Power's proposed revisions to the *Access Arrangement for the Western Power Network.*

The access arrangement information and its relevant appendices have been written to meet the requirements of section 4.2 and 4.3 of the Access Code, enabling the Authority, users and applicants to:

- understand how Western Power derived the elements of the proposed access arrangement

- form an opinion as to whether the proposed access arrangement complies with the Access Code

It includes:

- information supporting the price control in the access arrangement
- information supporting the pricing methods in the access arrangement
- information supporting the measurement of the components of approved total costs in the access arrangement
- information supporting Western Power's system capacity and volume assumptions

1.2.1 Access Code specific criteria and objective

All proposed revisions to the access arrangement are guided by relevant specific criteria and the Access Code objective, as defined in section 2.1 of the Access Code:

> *The objective of this Code is to promote the economically efficient:*
>
> *a) investment in; and*
>
> *b) operation of and use of*
>
> *networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.*

To assist the reader, relevant sections of the Access Code are referenced throughout this document where applicable.

1.2.2 Criteria for approval of a proposed revisions

Section 4.28 of the Access Code has the effect that the Authority's decision in relation to proposed revisions to an access arrangement is a 'pass or fail' assessment. Section 4.28 provides:

> *… when making a draft decision, final decision or further final decision, the Authority must determine whether a proposed access arrangement [to be read as proposed revisions] meets the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) and:*
>
> *a) if the Authority considers that:*
>
> *(i) the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) are satisfied — it must approve the proposed access arrangement; and*
>
> *(ii) the Code objective or a requirement set out in Chapter 5 (or Chapter 9, if applicable) is not satisfied — it must not approve the proposed access arrangement;*
>
> *and*
>
> *b) to avoid doubt, if the Authority considers that the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) are satisfied, it must not refuse to approve the proposed access arrangement on the ground that another form of access arrangement might better or more effectively satisfy the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable).*

In proposing revisions to an access arrangement there may be a range of outcomes which conform with the Access Code requirements. There will not be a uniquely correct outcome, as reasonable minds may differ on outcomes that satisfy those requirements. Subject to satisfying the Access Code requirements, it is for Western Power to determine the manner in which it will satisfy them.

The Authority must first assess whether Western Power's proposed revisions satisfy the Code requirements; it is not permissible for the Authority to move straight to a different, preferred outcome which may also satisfy the Access Code's requirements. It is only if Western Power's proposed revisions do not satisfy the Code requirements that the Authority may substitute its own assessment of what the revisions should be.

Western Power's proposed revisions to the access arrangement satisfy the Access Code objective and the requirements set out in Chapter 5.

1.2.3 Relevant legislation

The Access Code is the overarching legislation that informs the content of the access arrangement. Table 1 includes other relevant legislation considered when developing the proposed revisions to the access arrangement.

Table 1: Sample of legislation and licences relevant to Western Power's operation, services and service levels

Legislation	Description / summary of requirement
Access Arrangement 2010 (WA)	This document establishes key Western Power operational parameters such as services, service levels, target revenue and revenue adjustment mechanisms.
Code of Conduct for the Supply of Electricity to Small Use Customers 2010 (WA)	Regulates the behaviour of retailers and distributors when dealing with customers who consume less than 160 MWh of electricity per year.
Contaminated Sites Act 2003 (WA)	Requires Western Power to identify, record, manage and remediate contaminated sites within its operation. The Act also establishes significant penalties for non-compliance.
Dangerous Goods Safety Act 2004 (WA)	Requires Western Power to appropriately and safely store, handle and transport dangerous goods.
Electricity (Licensing) Regulations 1991 (WA)	Prescribes the overarching regime for the licensing of electrical workers and provides for the regulation of electrical work in Western Australia.
Electricity (Supply Standards and System Safety) Regulations 2001 (WA)	Creates obligations on network operators to ensure compliance with network safety requirements. The regulations also impose various reporting and audit requirements and incorporate a number of standards and codes to apply to network operators.

Legislation	Description / summary of requirement
Electricity Corporations Act 2005 (WA)	Established the four electricity corporations in Western Australia, sets out and limits the functions and powers of each corporation and their personnel, imposes corporate governance and director duty requirements, requires compliance with policy instruments and ministerial directions and imposes reporting regimes.
Electricity Distribution Licence EDL 1	The licence granted by the Authority which allows Western Power to operate the distribution network.
Electricity Distribution Regulations 1997 (WA)	Prescribes terms and conditions relating to applications for access to the distribution network, metering and charging relating to the use of the distribution network and technical regulation.
Electricity Industry (Licence Conditions) Regulations 2005 (WA)	General conditions applying to the granting of a licence, including compliance with other legislation such as the Electricity Industry Customer Transfer Code 2004 (WA) and Electricity Industry Metering Code 2005 (WA).
Electricity Industry (Network Quality and Reliability of Supply) Code 2005 (WA)	Sets out quality standards for network operators in relation to voltage fluctuations, harmonics, planned or significant interruptions, and monitoring and record keeping; creates a duty to disconnect supply if damage may result from a failure to meet the standards, as well as a duty to reduce the effect of any interruptions of supply.
Electricity Industry (Obligation to Connect) Regulations 2005 (WA)	Imposes the obligation on Western Power to connect, within a prescribed timeframe, a customer who applies for connection and whose meter point is within 100 meters of the existing Western Power Network and whose forecast annual demand is less than 160 MWh.
Electricity Industry (Wholesale Electricity Market) Regulations 2004 (WA)	Established the electricity market described in the *Electricity Industry Act 2004 (WA)*. Prescribes penalties and other consequences for a breach of the *Wholesale Electricity Market Rules 2004 (WA)*.
Electricity Industry Act 2004 (WA)	Established the Wholesale Electricity Market, the *Electricity Networks Access Code 2004 (WA)*, the *Code of Conduct for the Supply of Electricity to Small Use Customers 2004 (WA)* and the Electricity Ombudsman Scheme. Imposes licensing requirements on electricity industry participants and other requirements in relation to the supply of electricity to certain customers, the extension and expansion policy for network infrastructure, last resort supply and tariff equalisation.
Electricity Industry Customer Transfer Code 2004 (WA)	Establishes Western Power's requirements when transferring contestable customers between retailers.

Legislation	Description / summary of requirement
Electricity Industry Metering Code 2005 (WA)	Establishes requirements in relation to meters and meter installations, meter accuracy, metering services and documentation.
Electricity Networks Access Code 2004 (WA)	Establishes the requirements of Western Power's access arrangement.
Electricity Regulations 1947 (WA)	Prescribes minimum energy performance standards and sets out general requirements in relation to electrical appliances and general safety requirements for electrical work.
Electricity Transmission Licence ETL 2	The licence granted by the Authority which allows Western Power to operate the transmission network.
Electricity Transmission Regulations 1996 (WA)	Prescribes terms and conditions relating to applications for access to the transmission network, metering and charging relating to the use of the transmission network and technical regulation.
Environmental Protection Act 1986 (WA)	Provides for environmental impact assessments and approval of developments likely to have a significant impact on the environment; contains provisions dealing with the prevention, control and abatement of pollution and environmental harm, such as requirements to obtain licences and works approvals.
Environmental Protection (Noise) Regulations 1997 (WA)	Requires Western Power to comply with minimum standards relating to noise emitting from its assets.
Occupational Safety and Health Act 1984 (WA)	Requires Western Power to provide a workplace and work practices which sufficiently protect the safety and health of its employees and contractors.
Technical Rules 2007 (WA)	Details the technical requirements to be met by Western Power on the transmission and distribution network and by users who connect facilities to the transmission and distribution networks.
Wholesale Electricity Market Rules 2004 (WA)	Established the electricity market as prescribed by the *Electricity Industry Act 2004 (WA)*.

1.3 Structure and content

This is Western Power's third access arrangement and associated regulatory review with the Authority. The third access arrangement period (herein referred to as **AA3**) covers the five-year period 1 July 2012 to 30 June 2017.[21] For the purposes of this document, the first two access arrangement periods – 1 July 2006 to 30 June 2009 and 1 July 2009 to 30 June 2012 – are referred to as **AA1** and **AA2** respectively.

[21] Refer to section 1.5 for a summary of why we propose a move to a five-year period.

The structure and content of this document is informed by the AAI Guidelines. A summary and cross reference of how this access arrangement information meets the requirements of the AAI Guidelines is included at the end of relevant chapters in this document.

Capital and operating expenditure forecasts were developed in accordance with requirements of section 4.4.1, 4.4.3 and 5.5 of the AAI Guidelines. Details as to how the expenditure forecasts comply with the guidelines can be found in chapters 7 and 8 of this document and Appendix A: AA3 capital and operating expenditure report.

This access arrangement information provides context, rationale and justification for proposed revisions to the access arrangement and should be read in conjunction with the access arrangement document[22].

Building on the experience gained during AA1 and AA2 this document sets out:

- the revenue we will require during AA3 to support the economically efficient investment in and operation of the network, providing efficient network services and meeting regulatory and technical obligations
- proposed incremental improvements to the access arrangement and the incentive arrangements that apply to our service levels and cost efficiencies

This document comprises four parts:

- **Part A – Background and context.** This section includes an overview of Western Power and challenges for the AA3 period. It provides details of our governance, planning and delivery processes, and performance during AA2.
- **Part B – Investment proposal.** This section details and justifies proposed capital and operating expenditure requirements during AA3. It discusses the proposed service standard framework and service outcomes, demand forecasts and the methodology used to develop the investment proposal for AA3.
- **Part C – Target revenue.** This section details the proposed target revenue for AA3. It includes calculation of the value of the capital base, rate of return on investment, depreciation, performance under the regulatory adjustment mechanisms and the proposed price path.
- **Part D – Regulatory framework.** This section defines the reference services and proposed price controls, pricing methods and policies for AA3. It includes proposed revisions to regulatory adjustment mechanisms and details of changes to policies and access contracts.

The access arrangement information also includes a range of appendices and supporting information including regulatory financial statements (attached at Appendix H: Proforma regulatory financial statements), as required by section 3.1 of the AAI Guidelines.

1.3.1 Explanatory notes

All monetary amounts presented in this document are expressed in **real 30 June 2012 dollars** and apply to 1 July to 30 June regulatory years unless otherwise stated. Some tables may not add due to rounding.

[22] *Proposed revisions to the Access Arrangement for the Western Power Network*, Western Power, October 2011

1.4 Western Power's approach to preparing the proposed revisions

Access Code compliance

The proposed revisions to the access arrangement are guided by the relevant specific criteria and objectives of the Access Code. Specifically, we have proposed revisions that ensure the access arrangement meets the requirements of Chapter 5 of the Access Code and satisfies the primary Code objective[23].

Stakeholder consultation

We have also considered our customers' requirements, conducting a series of stakeholder engagements to help us understand how we can best support their needs throughout the forthcoming access arrangement period. Almost 100 key stakeholders including major customers, government agencies, peak representative bodies and local government authorities were engaged at forums held across Perth metropolitan and country areas. Particular focus was given to working more closely with the Authority and key government agencies (Department of Treasury, Department of Finance, Department of the Premier and Cabinet, Office of Energy) to provide visibility of the proposed investment, its financial impacts and benefits for the State.

More than 600 residents and small businesses were engaged via a telephone survey to help us understand how they value our services. Feedback from these engagements was fundamental to the development of our investment proposal and service standard framework for the AA3 period. While it is not always possible to incorporate everything that customers desire, the feedback was critical to ensure we appropriately balance customer requirements with regulatory obligations and other challenges.

Stakeholder consultation will remain an important part of our business practice as we aim to continue our improvement throughout AA3.

Performance during previous access arrangements

A key exercise when developing the proposed revisions for AA3 was to look back at our performance during AA1 and AA2. We conducted a thorough review of performance and governance activities, focusing on areas of weakness identified during the last access arrangement revision process. We also looked at how we can harness efficiencies achieved during the AA2 period and leverage them in AA3.

Experience in other jurisdictions

Regulatory precedent and the experiences of other transmission and distribution network businesses in Australia have also influenced the access arrangement revisions. Throughout the AA2 period, we have monitored regulatory decisions made by the Authority and its counterparts in the eastern states. Where appropriate, we have identified opportunities where adopting practices undertaken by the Australian Energy Regulator may enhance the outcomes to customers in Western Australia.

[23] See section 1.2.1 above.

1.5 Length of the access arrangement period

We propose that the forthcoming access arrangement period (referred to as AA3) covers five years (1 July 2012 to 30 June 2017). This is in contrast to the previous two regulatory periods, which each covered three years.

We consider that a five-year period will provide the following benefits:

- it will provide greater opportunity to effectively execute plans to deliver investment and services to customers
- it increases the strength of the incentives to improve on service and cost performance
- it reduces the process costs of undertaking the comprehensive access arrangement review process more frequently

Consistent with section 5.29 of the Access Code, the length of the forthcoming access arrangement period (AA3) is established by Western Power proposing a revisions submission date and a target revisions commencement date for the following regulatory period (AA4).

We propose that the access arrangement **revisions submission date** for **AA4** is **1 March 2016** and the access arrangement **target revisions commencement date** for **AA4** is **1 July 2017**.

This results in a five-year AA3 access arrangement period. The proposed revisions submission date for AA4 allows 15 months to conduct the review process for AA4. This 15-month period will provide sufficient time for the Authority and Western Power to complete the review process and implement any changes in preparation for the start of AA4.

2 An overview of Western Power

This chapter provides contextual information to help the reader understand Western Power's business operations, changes implemented during AA2 and challenges for AA3. This information is provided as background to later sections of this document and summarises:

- Western Power's business, the scale of its network and the role it plays in the Wholesale Electricity Market
- changes implemented during the AA2 period and how these shape proposed investment and performance during AA3
- challenges for AA3 of ensuring public safety, facilitating growth and security, maintaining service levels and investing efficiently for Western Australia's energy future

2.1 Key messages

- We own, operate and maintain the principal electricity network in the south west of WA delivering power to more than a million customers every day.
- Unlike many other network owners in Australia, Western Power is an integrated transmission and distribution network, also providing system management functions to ensure system security and support market efficiency.
- We operate an unconstrained network, which can require significant network investment to ensure there is sufficient network capacity to provide unconstrained access to all generators.
- The network challenges that will shape the investment and performance during AA3 include:
  - **addressing the underlying risk in the Wester Power Network** – safety, growth and security risks by their nature are 'latent' and their reduction would not necessarily be seen as desirable outcomes until related incidents occur
  - **asset condition** – we are now in a period when many assets are reaching the end of their serviceable lives. Similar to major networks in the eastern states, the Western Power Network was largely constructed in the 1960s and 70s, followed by an extended period of investment targeted at connecting new customers and generators.
  - **emerging technology** – during the period we will continue to investigate emerging technology that can improve the effectiveness of demand-side management and 'smart' energy solutions.

2.2 Who we are

Western Power connects people with energy. We own, operate and maintain the principal electricity network in the south west of Western Australia, delivering power to more than one million customers every day.

The Western Power Network consists of 76,000 km of overhead powerlines, 19,000 km of underground powerlines, 630,000 wood poles, 225,000 streetlights, 13,500 transmission and distribution substations and is one of the largest isolated networks in the world. It covers an area of 261,000m^2 and has a load that ranges from 1200 MW overnight to more than 4000 MW on the hottest summer day.

Unlike many other electricity network businesses in Australia, Western Power is an integrated transmission and distribution network owner. This presents unique challenges and opportunities as we plan, maintain and develop a network that can support the connection of new generation and large loads while keeping pace with the growing energy demands of new and existing customers. We also provide the system management functions to ensure system security and support market efficiency.

Figure 8: Western Power's role in the energy market

The Western Power Network is an unconstrained network. This means we are obligated to allow all generators connected to the Western Power Network to be generating at the same time. Where spare capacity is not available, network augmentation is required to allow new generators to be connected. The unconstrained network planning approach can require significant network investment to ensure there is sufficient network capacity to provide unconstrained access to all generators.

Our role is to facilitate growth in our state by working with generators, retailers and end-users to best understand their needs, provide access to the network and deliver energy safely, reliably and at an efficient price.

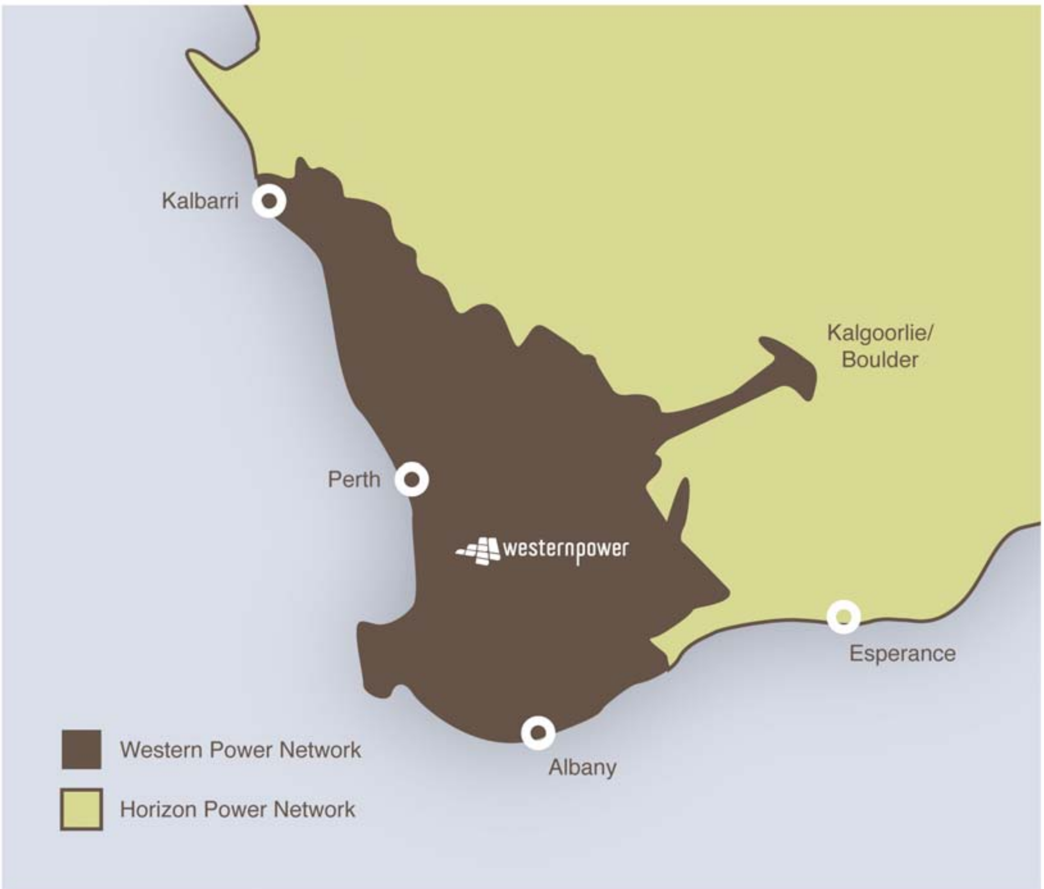

Figure 9: The Western Power Network, part of the South West Interconnected System

Since disaggregation in 2006, we have been on a journey of change as we adapt to our relatively new regulatory environment. The AA1 period, which covered the three years immediately after disaggregation, provided a steep learning curve as the former vertically-integrated Western Power became a stand-alone electricity network business subject to independent economic regulation.

Drawing on our experiences during AA1, we have made improvements throughout AA2 to many aspects of our service, process and governance. A review of performance during AA1, coupled with feedback from regulators, customers and other key stakeholders helped sharpen our focus and identify how we can operate more commercially as a regulated network business, increasing efficiency and improving our services.

While the change process at Western Power is ongoing, improvements to our processes and governance underpin our proposed investment and service for the next access arrangement period (AA3) and provide a strong platform for meeting the challenges ahead.

2.3 Challenges ahead

> *"With all energy markets around the world undergoing significant transformation, the Western Australian energy market is no exception as we respond to key challenges of climate change, energy security and energy affordability.*
>
> *"Over the next 20 years, Western Australia will have access to energy from a diverse range of traditional and new sources, with a greater range of renewable energy in the mix. This energy will be produced by competing businesses and located in areas that will require the provision of efficient transmission between the energy source and the consumers, operating in a more transparent, efficient and effective market."*
>
> **Hon Peter Collier, MLC**
> Minister for Energy
> March 2011

Western Power has an important role to play in the development of Western Australia's long-term energy future. The State Government's *Energy2031 Strategic Energy Initiative* outlines the vision and expectations of the network over the next 20 years, meeting the challenges of diverse generation sources, growth and smart technologies.

Our aim during AA3 is to create a platform for this vision by investing efficiently in the Western Power Network, ensuring it operates safely, has the capacity to support future growth and continues to provide an acceptable level of service. Delivering these three pillars is critical if we are to establish a network that can support the implementation of new technology in the future.

This must be achieved while realising opportunities to enhance the regulatory framework and working with the Authority and other key stakeholders to ensure the access arrangement best supports the Access Code objectives.

The network and regulatory challenges that will shape investment and performance during the AA3 period are summarised below.

2.3.1 Network challenges

Keeping the public safe

Western Power has a vast electrical network that impacts the general community. Our infrastructure crosses both public and private property, above and below ground. While an inherent risk exists in any electrical network, we have a responsibility to apply a prudent and diligent approach to managing the public safety risk associated with our assets.

The potential for electricity network assets to ignite bushfires is one of the most significant public safety risks for the Western Power Network. Approximately 25% of our wood poles are located in 'extreme' or 'high' bushfire risk areas. Our challenge is to ensure these distribution assets continue to operate safely and are replaced before they reach the end of their useful life.

The potential for electric shock is also inherent in distribution network assets such as overhead customer service connections. During the AA3 period, a primary focus will be on investing in activities that minimise the risk of harm to the public and reduce the potential for bushfires to be initiated by network assets. Details of our proposed investment program to reduce the public safety risk can be found in chapter 8 of this document.

Meeting growth and improving security of supply

Western Australia's population is forecast to grow from around 2.2 million people in 2009[24] to around 2.8 million in 2031[25] and will be a significant contributor to the state's energy demand. Approximately 130,000 new customers are expected to connect to the network in AA3, with maximum demand forecast to rise from 4332 MW in 2011/12 to 5061 MW by 2016/17. This continued growth highlights the ongoing challenge of ensuring the Western Power Network has capacity to be able to meet rising demand.

A further challenge is the need to improve network security. During AA2 investment to expand the capacity of the network was deferred as customer-driven work declined and projects were reprioritised in response to improvements to governance processes and the need to seek additional funding from Government. To keep pace with growth, reserve capacity in the network was absorbed as customers continued to connect.

While this policy was appropriate for the period, it is not sustainable over the long term. By the end of AA2 the level of reserve capacity remaining in the network will not be sufficient to allow the network to accommodate a significant unplanned outage event in peak demand conditions. Without investing to increase security, the risk of long duration widespread outages will increase throughout AA3.

Details of proposed investment to meet growth and security can be found in part B of this document.

Maintaining service levels

As demand on the network increases, so to does the challenge of ensuring service levels do not deteriorate. Customers expect levels of reliability and power quality to be maintained, particularly as their dependence on electrical equipment that is sensitive to frequency or voltage fluctuations increases.

Replacing poor performing or out-dated assets is critical to maintaining network performance. The Western Power Network currently contains a large proportion of assets that will require replacement during AA3 in order to maintain historical average service levels. Details of the proposed investment associated with asset replacement can be found in part B of this document.

There is also increasing pressure from customers to provide a similar level of performance on the edge-of-grid to that in urban areas. Balancing edge-of-grid customers' needs with funding challenges, efficient delivery and price outcomes is a key consideration for the AA3 period.

WA's energy future

As outlined in the State Government's *Energy2031 Strategic Energy Initiative*, technology for generating and distributing electricity will continue to evolve over the next 20 years. The existing network requires considerable modernisation to be able to support the uptake of photovoltaic systems, facilitate two-way flow of energy and support the introduction of new technology such as electric vehicles. Our challenge for AA3 is to facilitate government policy initiatives and prudently invest in network modernisation to support future generation and customer demands more efficiently.

[24] *Population Bulletin: 2009 Estimated Resident Population*, WA Planning Commission, October 2010.
[25] *Western Australia Tomorrow: Population Report No. 6*, WA Planning Commission, November 2005.

Managing pricing pressures

Over the past year there has been increased political and media focus on energy price increases. Customers in most Australian states and territories have seen real price increases and this is expected to continue into the future as we move toward 'cost reflectivity'. In Western Australia, these increases have perhaps been felt more sharply given that Government subsidies have meant that Western Australians have enjoyed real reductions in electricity prices over the last decade. This is shown in Figure 10, reproduced from an independent report on the Australian Energy Market Outlook in November 2010[26].

Rising energy costs have a range of contributing causes throughout the energy supply chain, including rising fuel prices and efforts to reduce carbon emissions. The increasing costs associated with upgrading ageing networks have been a common contributor throughout Australia and the Western Power Network is no exception.

Our challenge is to balance the public safety and security risks associated with not replacing infrastructure that is in poor condition with the inevitable price impacts increased investment will have on customers.

Figure 10: Comparison of historical state electricity prices (inflation adjusted)

[26] *Energy Market Outlook, Presentation to Multi-Party Climate Change Committee*, Rod Sims, Adviser to the Committee, 10 November 2010.

2.3.2 Regulatory challenges

The current regulatory framework in Western Australia is relatively new when compared to other Australian jurisdictions. While the Western Australian Access Code has remained relatively unchanged over the last five or so years, arrangements in other jurisdictions have evolved and been enriched by experience.

Strong consultation between the states and territories that are electrically connected has culminated in the development of a national set of arrangements based on input from governments, regulators, customers and network businesses.

Similarly, Western Power wishes to work closely with the Authority and other stakeholders and draw on experiences over the recent access arrangement periods to evolve and refine the Western Australian regulatory framework so that it can better support the Access Code objective. There is also an opportunity to learn from the experience of the national electricity market and adopt similar practices where it will deliver the best result for WA.

During the AA3 revisions process we have an opportunity to enhance elements of the regulatory framework, particularly the service standard framework that supports the delivery of valued services to customers and the calculation of the target revenue.

Details of proposed revisions to the incentive regime and target revenue are included in parts C and D of this document.

3 Performance in 2009/10 and 2010/11

This chapter sets out how Western Power has performed over the first two years of the AA2 period. It summarises the key outcomes for customers in terms of service, connections and safety and the investment undertaken to achieve these outcomes.

This chapter also highlights a number of improvements that Western Power has made to its planning and delivery arrangements, which have contributed to efficiency savings associated with proposals put forward as part of AA2.

3.1 Key messages

- Customers have received improved service throughout AA2 across a broad range of performance measures.
- We have outperformed targets for distribution reliability, the number of customer connections and street light repair times.
- While service has improved generally, during the final year of AA2 we will focus on improving service in areas that have not quite met performance expectations
- Service improvement during AA2 has allowed us to reach a standard where our AA3 investment can focus on maintaining overall service levels rather than further improving them.
- During AA3 our emergency response capability performed well, being tested by a number of emergencies and extreme weather events, including one of the most severe storms ever recorded in Perth.
- We invested $1.632 billion on capital works and $827 million to operate and maintain our distribution and transmission networks in 2009/10 and 2010/11.
- We have introduced a number of new governance improvements and new initiatives to improve our ability to efficiently invest in and operate the network.

3.2 Customer service

Service has improved throughout AA2, with customers experiencing better service today than they received during AA1. The following sections outline how we have performed across the key indicators of customer service:

- reliability of supply
- quality of supply
- security of supply
- call centre performance
- customer connections

3.2.5 Reliability of supply in the distribution network

We have improved reliability of supply each year during AA2 and performed significantly better than the targeted levels.

Reliability is usually described in terms of the duration and frequency of a supply outage. This is measured by the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). Figure 11 shows our performance in relation to the duration and frequency of outages. Note that a lower number represents an improvement in service for these measures.

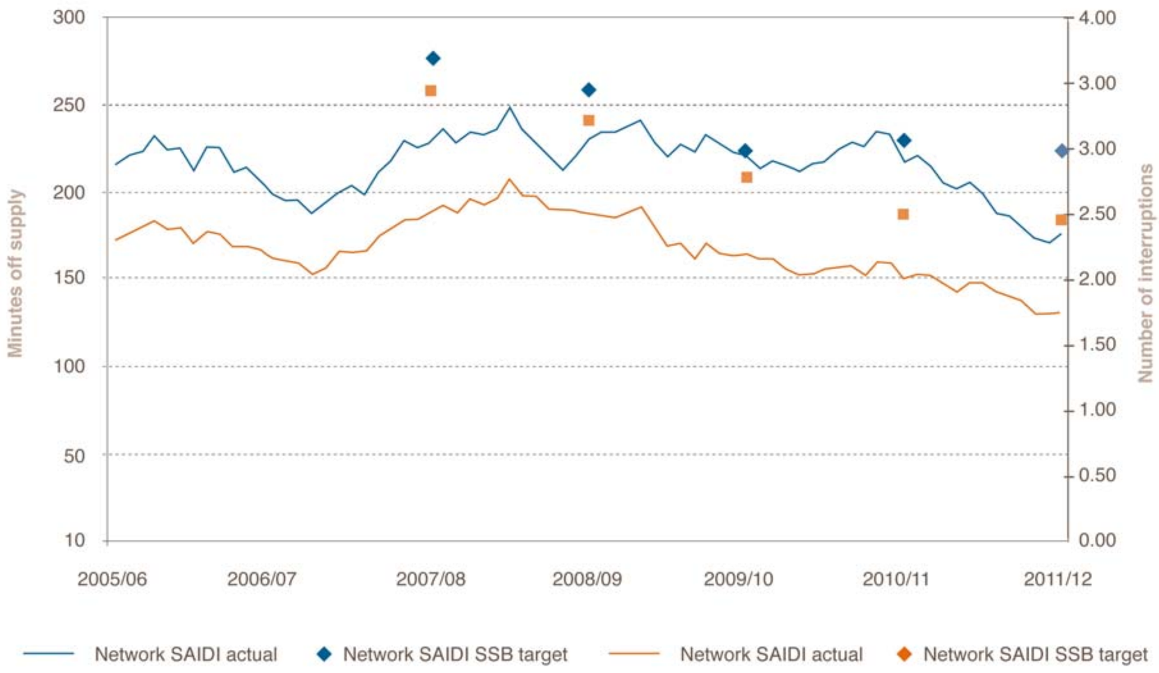

Figure 11: Historical SAIDI and SAIFI performance

We have achieved the improved AA2 service levels by delivering a number of reliability programs including the Summer Ready[27] and the Worst Performing Feeders program[28]. These were complemented with increased vegetation management and installation of automated switchgear. There was also a reduction in asset damage due to fires and vandalism. The generally mild weather during 2009/10 and 2010/11 was a significant contributor to the improved reliability performance.

We monitor the duration and frequency of interruptions by feeder type (CBD, urban, rural short and rural long). We also monitor whether the interruptions are caused by faults that occur on the transmission network or on the distribution network.

The current access arrangement (for the AA2 period) includes ten service standard benchmarks for distribution reliability.[29] We achieved nine of the ten distribution service standard benchmark targets in 2009/10 and all ten in 2010/11. This is shown in Table 2 and in Figure 12 and Figure 13. Note that a lower number means improved service.

[27] The Summer Ready program identifies and then prioritises the critical projects in Western Power's portfolio that need to be delivered prior to the summer peak demand to reduce the likelihood of customer outages.
[28] The Worst Performing Feeders program identified the top 40 feeders contributing to poor reliability, ranked by their individual SAIDI contribution, then carried out works including load transfers, feeder cable upgrades or installation of new feeders to improve average reliability to customers. The program was completed in 2009/10.
[29] We report against 74 other distribution and transmission network reliability indicators in the annual compliance report. Refer to *2009/10 Annual Performance Report, Electricity Distributors,* March 2010 on the ERA website www.erawa.com.au.

Table 2: Distribution reliability of supply – historical performance

Performance measure	2008/09	2009/10		2010/11		2011/12
	Actual	Target	Actual	Target	Actual	Target
SAIDI (minutes off supply)						
SWIN Total	225	230	217	224	176	213
CBD	29	38	1	38	30	38
Urban	161	165	156	162	120	153
Rural short	241	259	212	253	192	244
Rural long	589	612	661	588	529	556
SAIFI (number of interruptions)						
SWIN Total	2.21	2.50	2.00	2.46	1.79	2.41
CBD	0.15	0.24	0.02	0.24	0.24	0.24
Urban	1.65	1.92	1.55	1.89	1.34	1.83
Rural short	2.71	3.12	2.33	3.06	2.19	2.98
Rural long	4.32	5.00	4.17	4.85	3.76	4.80

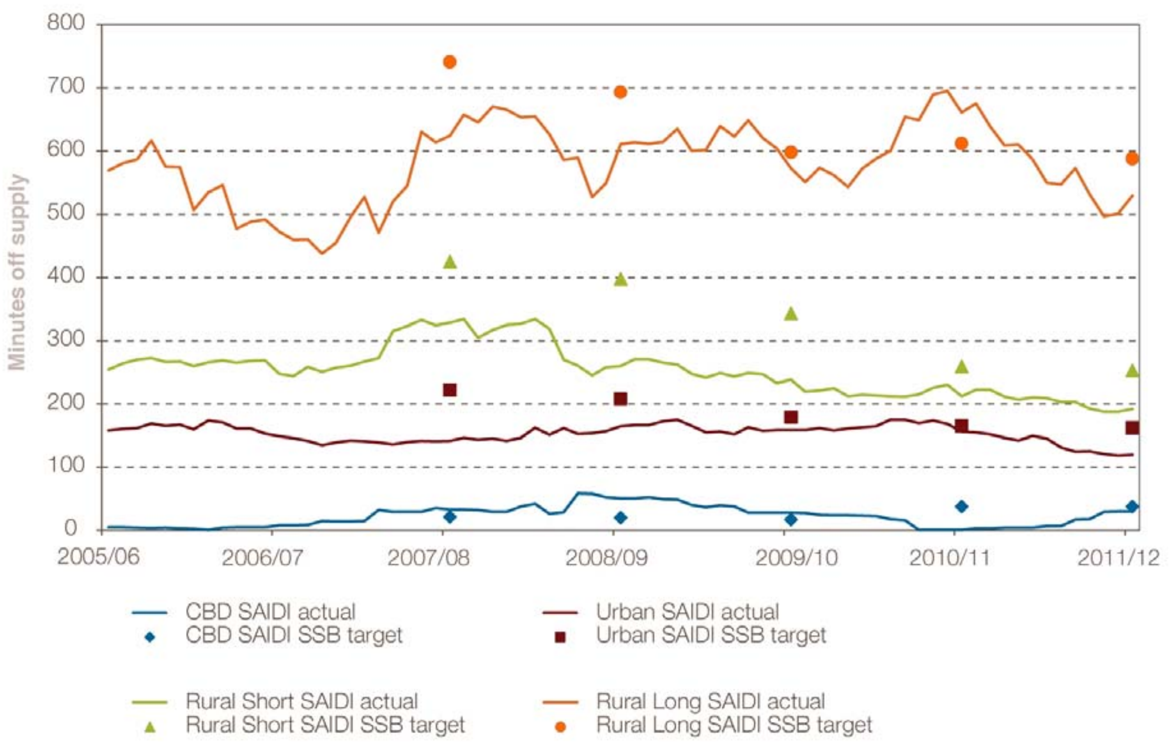

Figure 12: Historical SAIDI performance

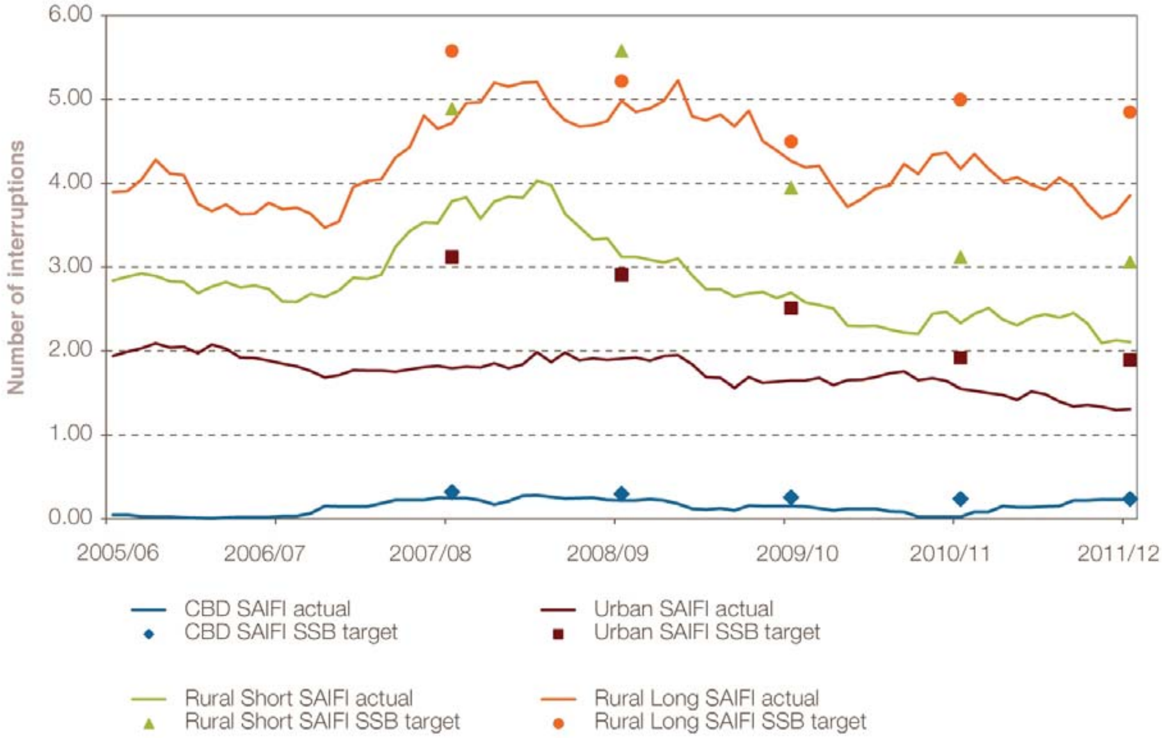

Figure 13: Historical SAIFI performance

Only customers on rural long feeders experienced a level of reliability that did not meet the targeted level in 2009/10. The minutes off supply for these customers deteriorated from 589 minutes in 2008/09 to 661 minutes in 2009/10, relative to a target of 612 minutes.

The deterioration for rural customers during 2009/10 was largely the result of damage from lightning. Figure 14 shows the historical impact of lightning on the SAIDI performance for customers on rural long feeders.

Figure 14: Impact of lightning on SAIDI performance – rural long feeders

However, benign weather and improved focus on service in rural areas led to reliability improving to a more acceptable level in 2010/11, with the minutes off supply being 529 minutes relative to a target of 588 minutes.

Figure 15 compares the performance of our distribution network during AA1 with other Australian distribution networks.

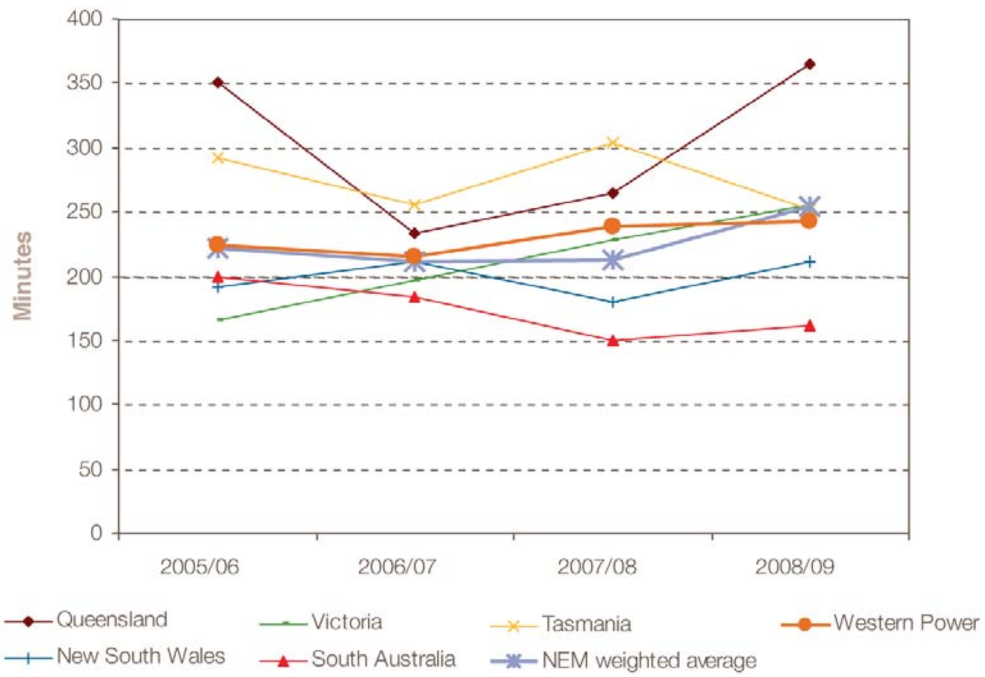

Figure 15: Comparison of SAIDI across the National Electricity Market (NEM) 2005/06 to 2008/09

Figure 15 shows that during the AA1 period[30], the Western Power Network compared favourably with many other networks. As discussed, our performance has improved significantly since this time and the level of reliability customers now experience is of a much higher standard.

As a result, we are not proposing any specific investment during the AA3 period to *improve* reliability, rather we will invest appropriately to maintain service at a level comparable with that which customers currently experience.

Details of the investment proposed in AA3 to maintain service levels can be found in chapters 7 and 8 of this document. The proposed service levels are discussed in chapter 5.

3.2.6 Reliability of supply in the transmission network

Reliability performance in the transmission network has been generally good. We have achieved four out of five transmission network reliability targets in each of the first two years of AA2.

The reliability of the transmission network is monitored in terms of duration and frequency, however, the measures are slightly different from distribution. The duration of outages is measured as system minutes interrupted on meshed and on radial networks. There is also an average outage duration measure. Frequency is covered by two measures: one that records the *number of loss of supply events of duration longer than 0.1 system minutes* (but less than 1 minute) and one that records *loss of supply events longer than 1 system minute*.

In 2009/10 the only target we did not meet was *loss of supply event frequency greater than 0.1 system minutes*. In 2010/11 we reached this target, but missed the target for *system minutes interrupted on the radial network*.

Table 3 and Figure 16, Figure 17 and Figure 18 summarise our performance over the first two years of AA2 compared to benchmarks. Note that a lower number represents better performance.

Table 3: Transmission reliability of supply – historical performance

Performance measure	2008/09	2009/10		2010/11		2011/12
	Actual	Target	Actual	Target	Actual	Target
System minutes interrupted (meshed network)	7.6	9.3	8.9	9.3	6.7	9.3
System minutes interrupted (radial network)	2.0	1.4	0.8	1.4	4.8	1.4
Loss of supply events (> 0.1 system minutes)	18	25	27	25	18	25
Loss of supply events (> 1 system minutes)	3	2	2	2	1	2
Average outage duration (minutes)	501	764	679	764	675	764

[30] Comparative data for 2009/10 and 2010/11 was not available at time of print.

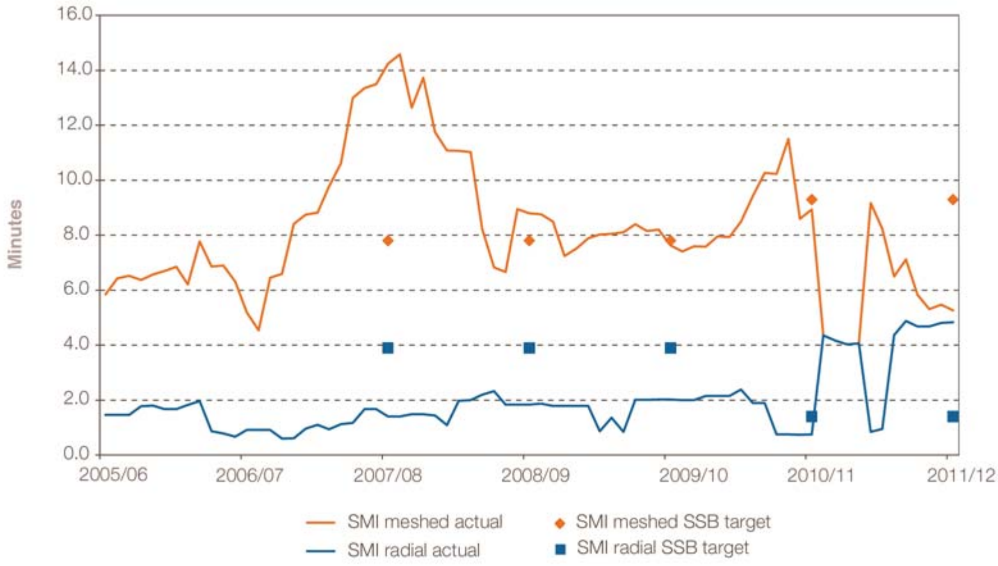

Figure 16: Historical system minutes interrupted

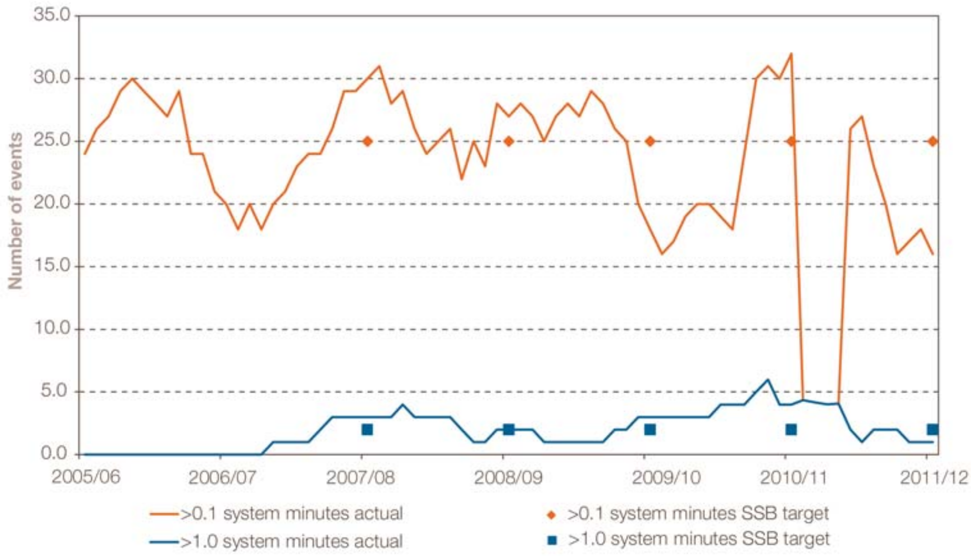

Figure 17: Historical loss of supply event frequency

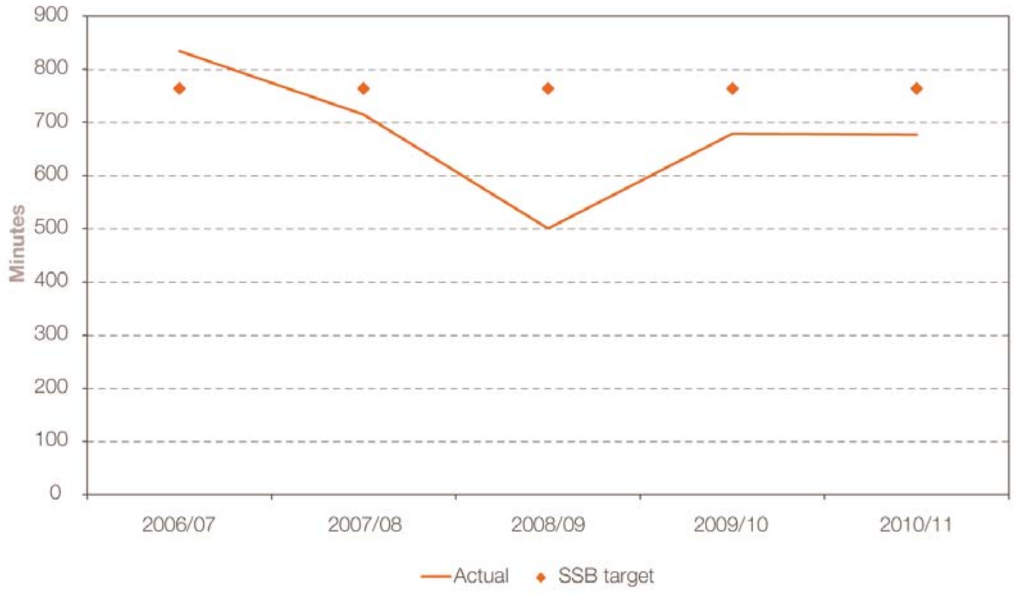

Figure 18: Historical average outage duration

After not quite achieving target in 2009/10, we were able to improve performance against loss of supply events longer than 0.1 system minutes from 27 in 2009/10 to 18 in 2010/11 through increased maintenance activities and revised work practices.

The below target performance in 2009/10 was due to frame leakage protection schemes that did not operate as expected, resulting in partial blackout of CBD and Goldfields substations. To help ensure this does not reoccur and to maintain current service levels, we will replace frame leakage protection schemes in AA3 so that the supply to customers is not inadvertently interrupted.

As previously mentioned, the only transmission network reliability target we did not meet in 2010/11 was system minutes interrupted in the radial network. After improving from 2008/9 to 2009/10, performance against this measure dropped to a level that was 3.4 system minutes worse than target.

The main contributor to this deterioration was a single event on 5 January 2011 when a pole-top fire affecting the Merredin – Carrabin – Yerbillon – Southern Cross 66kV line resulted in the loss of 3.45 radial system minutes. While no specific investment to improve performance against this measure is proposed, increased safety investment during AA3 (which includes pole-top fire mitigation) will reduce the likelihood of a similar event happening. This will help maintain performance at a level more consistent with the AA2 targeted levels.

Other than these two below-target instances, overall reliability performance in the transmission network during the first two years of AA2 has been good. As a result, during AA3 our objective will be to maintain overall service at a level comparable with current performance, targeting investment only where improvement is valued by customers and it is economically efficient to do so.

To ensure transmission-connected customers continue to receive good service, we are introducing a new customer-focused service measure for AA3 to better reflect their needs.

Details of the investment proposed in AA3 to maintain service levels can be found in chapters 7 and 8 of this document. The proposed service levels, including the customer-focused service measure for transmission-connected customers are discussed in chapter 5.

3.2.7 Security of supply

Circuit availability was substantially better than target in 2009/10 before declining in 2010/11. Circuit availability is a measure of the security of the transmission network. The likelihood of an interruption on the transmission network increases when circuits are not available.

Table 4 and Figure 19 provide information on our performance compared to target and over time. Note that a higher number represents better performance.

Table 4: Circuit availability – historical performance

	2008/09	2009/10		2010/11		2011/12
	Actual	Target	Actual	Target	Actual	Target
Circuit availability (% of total time)	98.3	98.0	98.4	98.0	97.9	98.0

Figure 19: Historical circuit availability

Circuit availability is directly related to the capital works program. The larger the capital works program, the more planned outages of transmission circuits are required to deliver the work and the lower the circuit availability.[31] As a result, the improvement in 2009/10 and subsequent deterioration in 2010/11 was largely due to a deferral of capital works from 2009/10 to 2010/11 leading to more planned outages in 2010/11 to undertake the additional work.

[31] Deterioration in circuit availability does not necessarily impact customers but it does increase the risk of an interruption to supply if an outage occurs.

The ‘smart planning’ program[32], which coordinates capital works to help reduce the number of planned outages required, prevented the increased 2010/11 works program having a greater impact on circuit availability.

Given the proposed increase in capital investment during AA3, we expect that the number of planned outages will increase. We propose that the performance target in the financial service incentive regime for AA3 is lowered slightly to reflect the inevitable effect on circuit availability. This is discussed in chapter 5 of this document.

To ensure customers are not adversely affected by the increase in planned outages, the smart planning initiative will continue throughout AA3.

3.2.8 Quality of supply

Our requirements in relation to the quality of supply exist in the Electricity Industry (Network Quality and Reliability of Supply) Code 2005. There are no targets explicitly stated in the access arrangement for power quality.

Power quality is the degree of consistency and quality of the electricity supply to the customer. A more consistent power supply with little fluctuation and fewer momentary interruptions allows a customer’s equipment to function correctly without damage or the need for machinery to be reset. Power quality issues include:

- low and high voltage
- fluctuating voltage
- television and radio interference

It is difficult to accurately measure our performance in relation to the quality of supply as it requires the installation of power quality meters. The majority of power quality issues are detected by our customers and reported to us. We then investigate and identify and undertake any remedial work required. As this measure is heavily reliant on customer reporting (which is outside our control), quality of supply has historically not been included in the financial service incentive scheme.

The number of power quality complaints per 100,000 customers has been trending downwards over the last 5 years, as shown in Figure 20.

[32] The ‘smart planning’ initiative implemented in 2009/10 aims to reduce the number, frequency and cost associated with network outages by coordinating all work that requires isolation of a particular part of the network. During the AA2 period, Western Power applied smart planning to 12 substations coordinating replacement capital investment, planned maintenance work and protection testing activities.

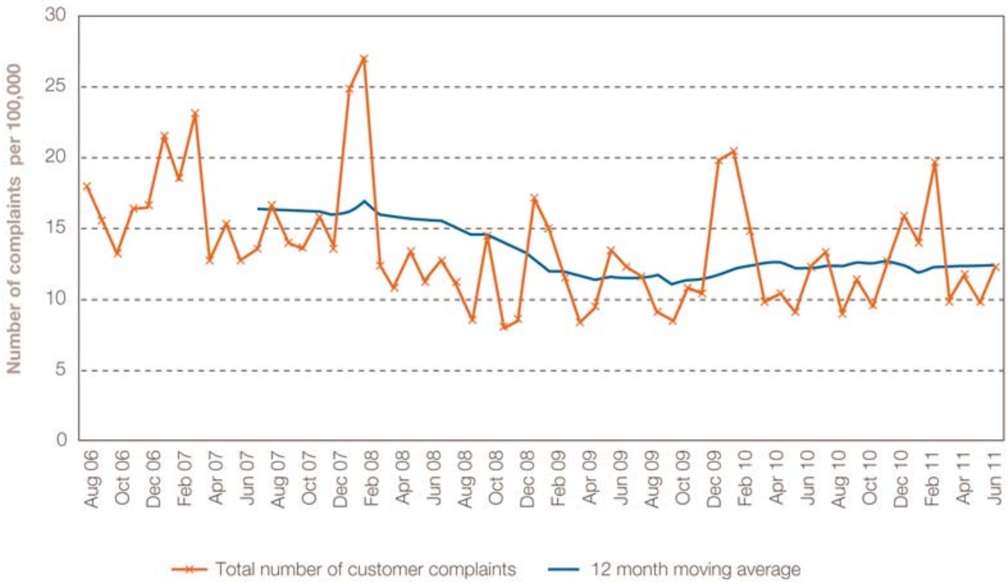

Figure 20: Customer complaints per 100,000 customers since August 2006

During AA3 we expect that the downward trend in complaints will continue.

We have a sample of power quality meters installed on our network, which provides some data on power quality. This limited monitoring suggests good power quality performance. All sites comply with harmonics requirements. Just over 99% of sites comply with the required voltage levels and just over 97% comply with voltage unbalance requirements.

We propose to install additional power quality meters during AA3. This will allow us to detect power quality issues effectively and respond to them more quickly.

3.2.9 Responding to emergencies and extreme weather events

We have faced many challenges over the first two years of AA2 resulting from emergencies or extreme weather events. To date our emergency response capability has performed well and we propose that it is maintained at existing levels for AA3.

Below is a sample of major events that Western Power successfully responded to.

- **Toodyay bushfire** – on 29 December 2009, a bushfire started 5 km south west of Toodyay on a day with maximum temperatures of 45.4 degrees Celsius with wind speeds of 44 kph. The bushfire caused extensive damage, affecting 138 residents and destroying 40 houses. In addition to the private losses, the blaze destroyed 161 power poles.

  Power was restored to the vast majority of customers within seven days, with Western Power crews working long hours and battling 40 degree temperatures to repair and replace damaged assets.

- **Pole-top fire activity** – on 7 February 2010, light rain followed the second longest dry spell on record. The light rain caused numerous pole-top fires affecting customers in Perth's northern suburbs, Rockingham and the Harvey area. In addition, the Manning substation blacked out due to a pollution flashover. Approximately 54,000 customers were without power.

Almost all customers were restored on the day, with the average outage lasting only two hours.

- **March 2010 storm** – on 22 March 2010, a severe storm hit the Perth metropolitan and surrounding regional areas, bringing heavy rainfall, hail and strong winds up to 120 kph. Power supplies were disrupted to around 250,000 customers. We recorded 7,795 individual network faults in two hours including 54 faults on the transmission network and four major substations blacked out. We managed around 46,000 service calls in two hours (more than six calls per second) and over 200,000 calls over the next four days.

  Power to more than 100,000 properties was restored within 24 hours, with power restored to all customers in the metropolitan area by 26 March 2010.

- **North Fremantle substation fire** – on 7 April 2010 there was a fire at the North Fremantle substation switch room. The fire started following an external fault on one of the distribution feeders. The power transformers with a combined load of 4.4 MW tripped, affecting 2,791 customers.

  Power was restored to all customers the same day through contingency works (use of rapid response spare transformer and ring main units) as an interim solution.

- **Strong winds**– on 29 January 2011, gusts of wind up to 126 kph were recorded at Cunderdin airport[33]. The storm resulted in damage to both transmission and distribution equipment, with faults at six zone substations and on 115 feeders. More than 350 power poles were damaged. Approximately 71,000 customers in the Wheatbelt and Mid West regions were affected.

  Despite the widespread destruction, the average restoration time was around 13 hours.

During 2009/10 and 2010/11 our emergency response capability minimised the extent and duration of outages experienced by customers. The cost of responding to these events is considered in developing and establishing our crisis management plan. Costs incurred in response to an event are recorded in our corrective emergency and corrective deferred operating expenditure categories.

The impact of these events is not included in performance reporting where the impact meets the ‘major event day’ threshold[34] or is classified as a force majeure event. These thresholds and classifications ensure that we are not inappropriately penalised for events that are beyond our control.

3.3 Call centre performance

Our call centre performance has remained strong throughout the AA2 period. We receive approximately 1 million calls from customers per year with around 80% or more of these calls responded to within 30 seconds.[35] Figure 21 shows our call centre performance over time.

[33] Source: *WA Climate Services Centre, Bureau of Meteorology*
[34] The major event day threshold changes each year and 6.54 minutes in 2009/10 and 6.06 minutes for 2010/11.
[35] Call centre performance is measured based on calls to the fault line answered within 30 seconds, as per the service standard benchmark definition in chapter 4 of the third access arrangement contract.

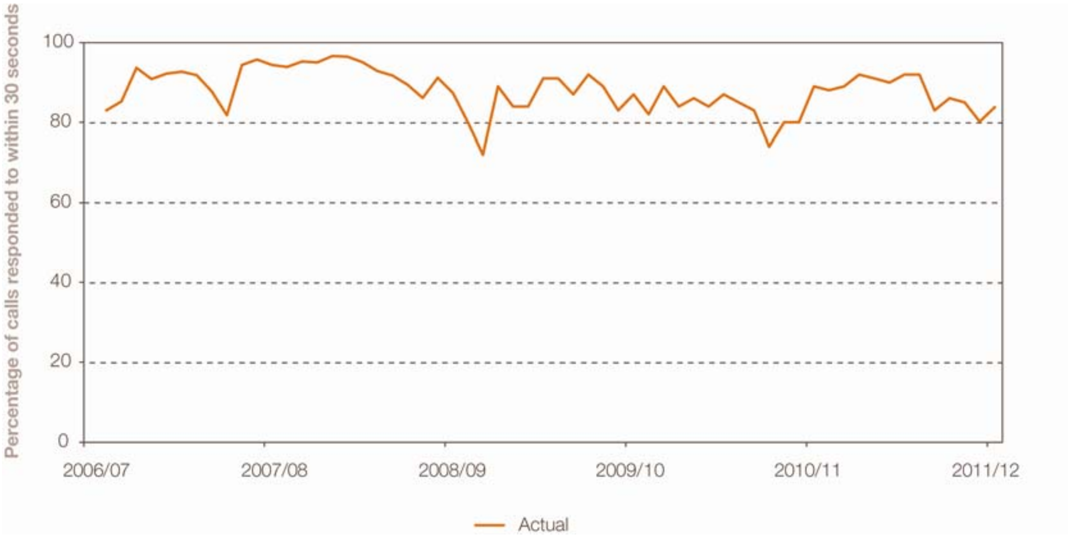

Figure 21: Call centre performance

In 2009/10 Western Power introduced new 24-hour call centre operations using a mix of automated technology and call centre operators. The new automated power restoration function has significantly improved efficiency, with half of all customers that have heard the automated power restoration choosing not to speak to an operator.

Given the value that customers receive from call centre performance, we propose that call centre performance is included as a service standard benchmark for the AA3 period. This is discussed further in chapter 5 of this document.

3.4 Customer connections

We connected an additional 47,763 customers to the network during the first two years of AA2. This is a 5% increase from 958,667 customers in 2008/09 to an estimated 1,006,430[36] in 2010/11, as illustrated in Figure 22.

The energy we deliver to customers has increased by 4.1% from 13,359 GWh in 2008/09 to an estimated[37] 13,907 GWh in 2010/11, as also illustrated in Figure 22. The actual/estimated energy consumption was 0.8% and 2.3% higher than the forecast energy consumption in 2009/10 and 2010/11 respectively.

Figure 22 also shows that the peak demand increased by 7.2% from 3,341 MW in 2008/09 to 3,581 MW in 2010/11.

[36] *Energy and customer number forecasts for the AA3 period (2012/13 to 2016/17),* Deloitte, February 2011.

[37] Due to the meter reading cycle, the actual energy consumption for 2010/11 was not available at the time of this submission.

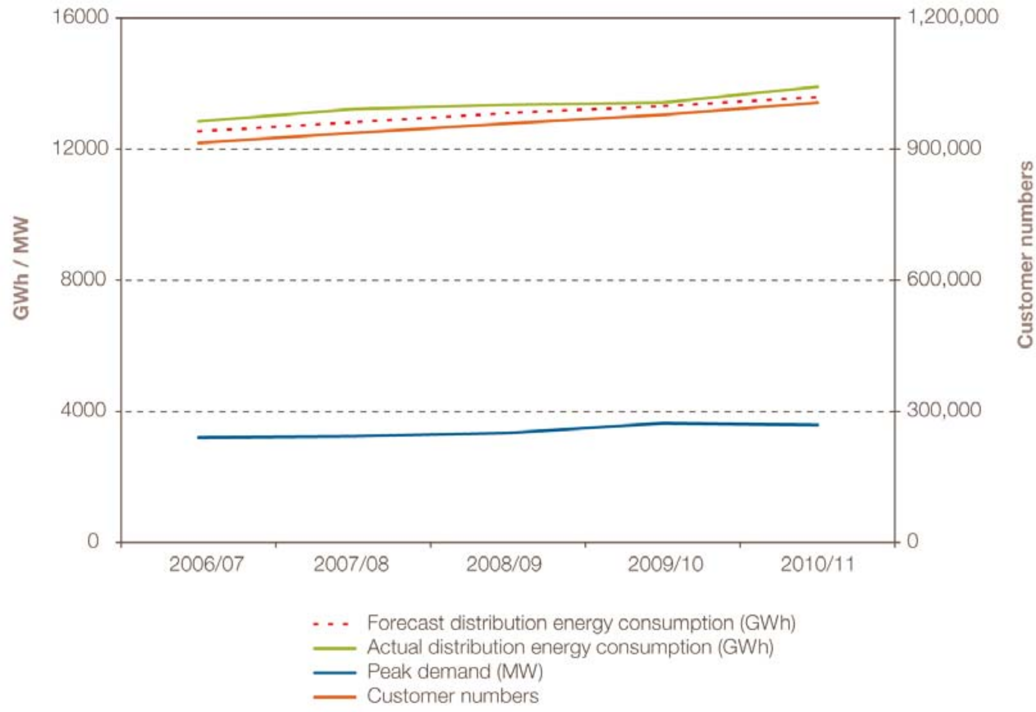

Figure 22: Forecast and historical energy consumption and historical customer numbers[38] and peak demand[39]

In addition, we have connected over 450 MW of generation and 56 MVA of large block loads, including:

- connection of the Binningup Desalination Plant
- connection of the Mumbida and Collgar Wind Farms
- expansion of the Jandakot Airport (Lukin substation)
- connection of the Geraldton Port Authority (Rangeway substation)

3.5 Streetlights

We have outperformed our targets in relation to streetlight repair times. We operated and maintained 223,172 streetlights in 2009/10 and 230,275 streetlights in 2010/11, a 3.2% increase from 2009/10 to 2010/11. Of these, 84% are located in the Perth metropolitan area and major regional towns.

We are required to repair any faulty streetlight within five days in the Perth metropolitan area and within nine days in remote and rural towns. Table 5 and Figure 23 show our performance in relation to streetlight repair times.

[38] Customer numbers were not forecast for the AA2 period.
[39] The peak demand forecast that formed the basis of the AA2 submission was at the zone substation level rather than the system level, as discussed further in section 6.2 of this document.

Table 5: Time to repair streetlights – historical performance

Time to repair streetlights (days)	2008/09		2009/10		2010/11	
	Target	Actual	Target	Actual	Target	Actual
Perth metropolitan area	5.0	3.7	5.0	2.0	5.0	1.4
Major regional towns	5.0	3.7	5.0	2.0	5.0	1.5
Remote and rural towns	9.0	4.1	9.0	1.7	9.0	1.7

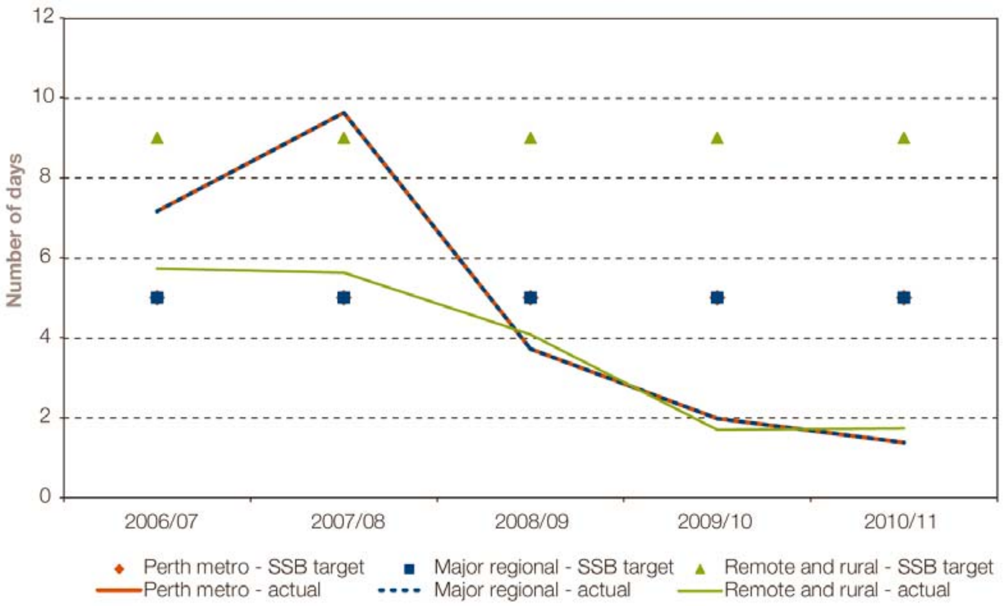

Figure 23: Historical street lighting repair times

The significant improvement in streetlight repair times during AA2 is a result of a number of improvement initiatives including moving from a four-year bulk globe replacement program to a three-year program, which reduced the number of failures.

3.6 Safety

Our safety performance has improved throughout the AA2 period. Public safety incidents[40] reduced from an average of 12 per month in 2009/10 to 11 per month in 2010/11 and our LTIFR[41] reduced from 2.6 in 2009/10 to 1.9 in 2010/11, (see Figure 24 and Figure 25).

[40] Performance is measured by average number of incidents over a rolling 12 month period.
[41] Lost time injury frequency rate.

Figure 24: Public safety incidents, average per month

Figure 25: LTIFR monthly rolling average v target

Our infrastructure crosses both public and private property, above and below ground. While an inherent risk exists in any electrical network, we have a responsibility to properly manage public safety risks associated with our assets.

We have invested $524 million in targeted safety programs in the first two years of AA2 including a bushfire mitigation program and targeted asset management programs for conductors, poles and connections. While safety performance will always be hugely contingent on external factors such as adverse weather, our aim is to achieve as much as we can to eliminate the factors that are within our control, such as ensuring our assets are in good condition.

There are 176,000 wood poles located in 'extreme' or 'high' bushfire risk areas. A failed wood pole presents multiple hazards. The pole itself can harm people or damage property and energised power lines contacting the ground can cause electric shock or, in very specific conditions, cause fires.

By the end of AA2 we plan to have doubled the number of poles reinforced and replaced compared to AA1. This increase is required to ramp-up for our AA3 pole reinforcement and replacement program, discussed in chapter 8 of this document.

At the end of AA1 there were 272,000 obsolete overhead customer service connections in the Western Power Network. Historically these connections, which link customers' homes to the distribution network, are responsible for an average of 80% of the total electric shocks attributed to our assets each year.

By the end of AA2 we will have replaced more than 100,000 of these potentially dangerous connections and will increase the program in AA3 to replace the balance by the end of 2015/16.

The network also contains 53,650 km of overhead power lines, known as 'conductors'. All overhead electricity networks carry an inherent public safety risk due to the potential for conductors to fall or clash due to equipment failure, extreme weather or other external factors. During AA2 we will replace 718 km of conductors that are in the poorest condition to reduce this risk.

Our targeted safety related programs will achieve the following outcomes by the end of the AA2 period:

- **reduction in the likelihood of bushfires caused by Western Power assets –** this will be achieved by continuing the bushfire mitigation program. The program includes implementing silicone solutions to prevent pole top fires, and replacing wooden poles and expulsion drop out fuses in targets extreme and high risk fire areas. It also includes partnering with the Fire & Emergency Services of Australia (FESA) to implement a fuel reduction program in the Perth Hills and conducting a summer safety campaign focused on fire prevention. The number of asset initiated fire events for 2010/11 has already reduced by 13% compared to 2009/10 as a result of this program. There has also been a reducing trend in the number of wires down incidents as a result of targeted (poor condition) conductor replacement
- **reduction in the number of unassisted[42] pole failures –** this will be achieved as a result of improvements we have made to the condition monitoring of our wood pole population and by increasing volumes of pole replacements and reinforcements
- **replacement of a further 90,000 overhead customer service connections** – we will continue our program to replace obsolete and potentially dangerous overhead customer service connections. There were 272,000 identified at the end of the AA1 period. The work delivered during AA2 will enable the balance to be replaced during AA3

Despite this improved safety performance, the risk of public safety incidents remains significant, largely as a result of the condition and age of network assets.[43] The progress made during AA2 is a platform for increased investment in mitigating public safety risks that is essential for AA3, particularly regarding distribution wood pole replacement. The required safety investment for AA3 is described in chapter 8 of this document.

[42] Unassisted means not attributable to an external factor such as storms, third party collisions or bushfire.

[43] Around 75% of total distribution conductor population is above 40 years old (approximately 51,500km).

3.7 Expenditure

During the first two years of AA2 have invested $1.632 billion on capital works and $827 million to operate and maintain the distribution and transmission networks. This is 32% less investment than was approved by the Authority for capital works and 7% less than the approved expenditure for operating and maintaining the network.

Table 6: Actual expenditure for 2009/10 and 2010/11 compared to regulatory approved expenditure

Expenditure type ($ million real at 30 June 2012)	2009/10	2010/11	Total
Capital investment (actual)	872.1	759.8	1631.9
Capital investment (forecast)	1004.7	1,403.5	2,408.2
Capital investment variance	**-132.6**	**-643.7**	**-776.3**
Operating and Maintenance costs (actual)	391.2	436.0	827.2
Operating and Maintenance costs (forecast)	389.9	496.2	886.1
Operating and Maintenance costs variance	**+1.3**	**-60.2**	**-58.9**
Total actual	1,263.3	1,195.8	2,459.1
Total forecast	1,394.6	1,899.7	3,294.3
Total variance	**-131.3**	**-703.9**	**-835.2**

Our operating and capital investment compares favourably with other electricity utilities on the basis of key investment drivers, maximum demand and line length (for both distribution and transmission) and number of customers (for distribution). The transmission operating investment is low relative to other transmission utilities as Western Power has a relatively high capital to operating investment ratio. Refer to section 7.9 and section 8.9 for a detailed comparison of our expenditure compared to our peers.

3.7.1 Capital investment

Governance improvements made over the course of AA1 and AA2 led to reconsideration of our capital works requirements and increased discipline on our investment decisions. Although this delayed some of the proposed AA2 work, the improvements will allow the business to continue to deliver economically efficient investment and valued services to customers during AA3.

The AA2 period has also seen a reduction in customer-driven work resulting from the global financial crisis and a tightening of State capital investment. These factors, combined with the deferral of several major projects led to a lower level of capital investment in 2009/10 and 2010/11 than was originally approved by the Authority.

In summary, for 2009/10 to 20010/11:

- transmission capital investment was 58% less than forecast
- distribution capital investment was 18% less than forecast
- business support capital investment was 11% less than forecast
- IT capital investment was 17% higher than forecast

Figure 26 illustrates the actual total capital investment compared to forecast.

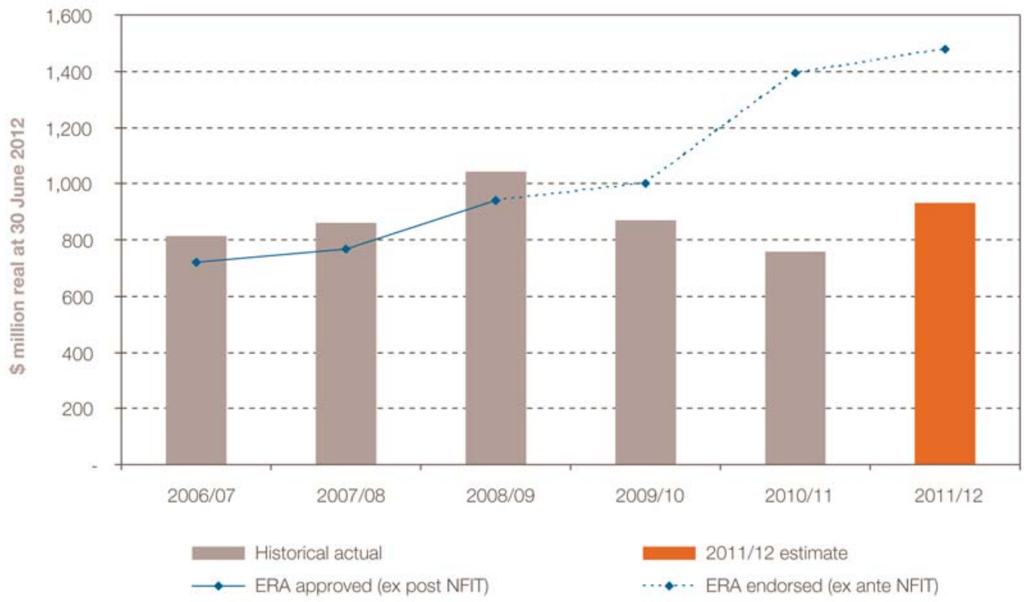

Figure 26: Forecast and historical capital expenditure

The less than forecast capital investment also resulted from a range of efficiency initiatives that have resulted in better value from contractual arrangements, improved delivery mechanisms and market testing of input costs. Favourable weather conditions, which resulted in fewer failures, overloads and outages and subsequently less remedial activity, also contributed to the lower than predicted spend.

We faced significant uncertainty in relation to available funding for the forecast work program in 2010/11. The funding provided for in the State budget was less than that approved by the Authority for the AA2 period. We engaged with the Department of Treasury and Finance[44] to secure the additional funding which, in the most part, was provided. However, the uncertainty regarding the access to additional funds resulted in considerable re-work to prioritise the work program and timetable.

The major variances to forecast were in growth-related investment, particularly transmission growth in 2010/11. The significant differences between actual growth-related investment and forecast will be addressed through the investment adjustment mechanism, which requires us to return revenue to customers where investment in growth has been less than forecast.

This mechanism, which we intend to continue in AA3, ensures that neither customers nor Western Power will be penalised or rewarded inappropriately for variations from forecast in growth-related capital expenditure.

Details of the capital investment program during 2009/10 and 2010/11 and variances from forecast are included in Appendix B.1: AA2 capital expenditure report.

[44] Now separated into the Department of Treasury and the Department of Finance.

3.7.2 Operating expenditure

The lower level of operating expenditure relative to forecast in 2009/10 and 2010/11 can be attributed to a range of efficiency initiatives implemented by the business, combined with favourable winter weather conditions.[45] Efficiency initiatives implemented during the first two years of AA2 include:

- **improved delivery mechanisms** – improvements were made across the entire supply chain, including more competitive procurement practices[46] and the reverse auction process[47]
- **market testing of input costs** – costs have been benchmarked against other businesses in the electricity supply sector resulting in competitive pricing and a reduction in the costs of some materials[48]
- **works packaging** – distribution work is issued through large scale, incentive-based contracts to large external contractors that have the capacity to deliver end-to-end construction and operational work at more economically efficient rates
- **project optimisation** – processes and systems that encourage optimisation across projects and programs was introduced. This targets distribution and transmission capital and operating expenditure, as well as encouraging all internal stakeholders to identify opportunities for cost reductions and efficiencies, particularly in the maintenance and asset replacement programs[49]

[45] For example, favourable weather conditions contributed to $15 million in savings from not having to deploy emergency response generators during the winter months over 2009/10 and 2010/11.
[46] For example, Western Power's improved inventory practices have reduced inventory expenses leading to a reduction in working capital investment of approximately $17 million. At the same time, service levels to internal and external customers increased by over 50%. In addition, a review of transmission primary plant vendors resulted in a new preferred vendor arrangement for power transformers that will deliver better value for money for the business expected to result in $1 million in savings over the AA3 period.
[47] An online reverse auction sees the roles of buyers and sellers reversed. In an ordinary online auction (also known as a forward auction) such as eBay, buyers compete to obtain a good or service, and the price typically increases during the auction time. In an online reverse auction, sellers compete to obtain business and prices typically decrease during the auction time.
[48] Examples of reduced material costs include a 25% reduction in the average cost for the replacement of a transmission pole since the start of the AA2 period and a unit cost reduction of 36% per bay achieved in the vegetation management program.
[49] Equivalent to $1.7 million in savings per year from improved works packaging and scheduling (savings on mobilisation and administration costs), combined with more competitive market rates as a result of work packaging changes (cheaper unit rates) delivered through the smart planning and distribution packaging initiatives.

Figure 27: Forecast and historical operating expenditure

The focus for the 2009/10 and 2010/11 expenditure program has been on customer connections, asset replacement, maintenance and the development of smarter technologies to address peak demand.

We have identified some additional costs that will be incurred in 2011/12 that will lift our operating and maintenance expenditure above the levels achieved in 2010/11. These are discussed further in chapter 7 of this document.

3.8 Governance and efficiency initiatives

In making its determination on AA2, the Authority was critical of Western Power's governance practices. In particular, fundamental flaws in the documentation and reporting of historical investment were highlighted. Consequently, the Authority wrote-down the value of the assets constructed during the previous access arrangement period (AA1). The Authority also intimated a degree of inefficiency in Western Power's delivery of works and deficiencies in the management of operations.

Our governance arrangements have been continually improving since our formation in 2006. In response to the Authority's criticisms and the funding uncertainty, we sharpened our focus on initiatives to improve strategic, planning, delivery and compliance processes. This is part of our objective to accelerate the transition of the organisation's culture from one that is highly technical and engineering-based to one that is commercially astute with more focus on efficiency and customer service.

We continue to implement governance improvements to be able to ensure and provide assurance that we make good commercial decisions and invest efficiently. Examples of governance improvements delivered during the first two years of AA2 include:

- establishing the planning, asset management and delivery system, including documents that guide and support efficient planning and delivery of investment.

These include the Network Investment Strategy, the Transmission Network Development Plan, the Network Management Plan, the Works Delivery Strategy and the Approved Works Program

- developing a more customer-friendly annual planning report and robust analysis of transmission capacity expansion and generation driven projects (which comprise around 70% of the transmission capital investment)
- ongoing review of engineering standards including economic assessment to ensure both the technical and economic value of our standards
- building a requirement to demonstrate compliance with the new facilities investment test into our business case process
- embedding the options analysis framework that formalises the methodology for developing, analysing and selecting the most efficient and appropriate options to address network challenges. This includes the revised investment evaluation tool[50]
- introducing holistic works programming that includes processes and systems that encourage optimisation across projects and programs
- embedding the formal process to govern business plans and execute capital projects, capital programs and maintenance programs through the works program governance model. This process ensures a rigorous and documented process for initiating, developing and executing works
- re-evaluating and improving the efficiency of delivery mechanisms, including termination of an existing alliance agreement, entering into a new alliance agreement and appointment of three distribution partners. The majority of distribution work is issued through large scale, incentive-based contracts to large external contractors that have the capacity to deliver end-to-end construction and operational work efficiently

These changes were complemented by:

- improved understanding of the regulatory regime, process and requirements across the business
- establishment of an annually reviewed cost and revenue allocation method to guide the translation of our financial accounts into the regulatory reporting requirements
- improved compliance through the development of a compliance model
- improved IT tools, including enhanced works reporting and improved project management tools
- improved management of inventory and purchasing

Each of these initiatives has contributed significantly to improving our overall approach to ensuring that:

- capital investment is subject to rigorous and robust governance and control processes and is compliant with NFIT
- forecast capital investment for the AA3 period has been subject to effective governance processes
- the business has implemented a number of controls on investment to efficiently minimise costs

[50] The 'Investment Evaluation Tool' replaces the 'Financial Evaluation Model' as a mandatory accompaniment to all capital project and program business cases. The improved tool allows for modelling and financial analysis of multiple options at a time.

3.8.1 Performance under the regulatory incentive mechanisms

There will be a negative $32.7 million adjustment to our target revenue for AA3 resulting from performance against the regulatory incentive mechanisms during the first two years of the AA2 period[51]. These mechanisms are designed to simulate the effect of competitive markets where firms are rewarded or penalised based on their ability to provide continuous improvements in costs and services compared to their peers.

Below is a summary of performance against the regulatory incentive mechanism:

- **service standards adjustment mechanism** – this mechanism provides financial incentives for us to maintain and improve service levels. This mechanism is based on the net position at the end of the AA2 period. To date these rewards total $19.7 million
- **gain sharing mechanism** – there will be no increment to revenue for this mechanism with respect to 2009/10 and 2010/11 despite achieving reductions in relevant operating and maintenance costs. This is because we were not able to meet all of the 19 service standard benchmarks (SSBs) simultaneously during any one year. This is a foregone benefit of $226.3 million
- **investment adjustment mechanism** – this mechanism ensures that customers only pay for investment related to growth that actually occurs. During the first two years of AA2, we spent less on investment related to growth than forecast and therefore we will be required to return $41.7 million to customers in AA3

We must understand the balance between these mechanisms to maximise the rewards. For example, if we reduce our costs and our service levels deteriorate, the cost efficiency rewards may be offset by penalties under the service incentive scheme. These rewards and penalties are not realised until the subsequent access arrangement period and then only when the results are able to be measured.

We will also be seeking $6.9 million (in present value terms) additional revenue in AA3 to cover the costs associated with the March 2010 storm. Where events are unforeseen and result in costs that we cannot avoid, cannot insure and do our best to minimise, we are able to recover those costs in the next access arrangement period.

[51] Based on performance in 2009/10 and 2010/11. We have not attempted to forecast performance in the final year of AA2.

4 Planning, management and delivery

This chapter provides an overview of Western Power's long-term planning, asset management and works delivery system.

It summarises the processes we employ to ensure capital investment and operating expenditure is efficient. It provides an overview of our network objectives and outlines our broader processes for ensuring efficient execution of the end-to-end works program.

4.1 Key messages

- Our planning, asset management and works delivery system governs capital investment and operating expenditure on the network.
- The system is designed to ensure actual investment achieves the identified objectives, is economically efficient and in line with good electricity industry practice. It includes the following key documents:
    - **Network Investment Strategy**
    - **Transmission Network Development Plan**
    - **Network Management Plan**
    - **Approved Works Program**
    - **Works Delivery Strategy**

'Good electricity industry practice' is defined in the Access Code as:

> *... the exercise of that degree of skill, diligence, prudence and foresight that a skilled and experienced person would reasonably and ordinarily exercise under comparable conditions and circumstances consistent with applicable written laws and statutory instruments and applicable recognised codes, standards and guidelines.*

- These key documents are interconnected, regularly refreshed and define the processes for the entire planning and delivery of network investment.
- Our planning and delivery processes are designed on the principle of efficiently minimising costs and are consistent with the requirements of the regulatory test[52], new facilities investment test and section 6.40[53] of the Access Code.
- Our network management and investment planning tools ensure that decisions about what to invest, when to invest and how to invest all emphasise the lowest sustainable cost of delivering services over a reasonable planning horizon.
- All our processes are regularly monitored and audited to ensure they remain consistent with the Access Code and that the right level of expenditure occurs on the right things at the right time.

4.2 Network Investment Strategy

The Network Investment Strategy articulates the reasons why we invest in the network. It includes network objectives and guiding principles to consider when making investment decisions. The strategy also identifies the drivers for investment.

[52] For major augmentations as required under Chapter 9 of the Access Code.
[53] Section 6.40 states 'Subject to section 6.41, the non-capital costs component of approved total costs for a covered network must include only those non-capital costs which would be incurred by a service provider efficiently minimising costs.'

Network objectives

Each network objective is described in terms of the outcome we seek to deliver and the goals we have established to determine if the objective is being achieved. There are four network objectives, which are summarised in Figure 28.

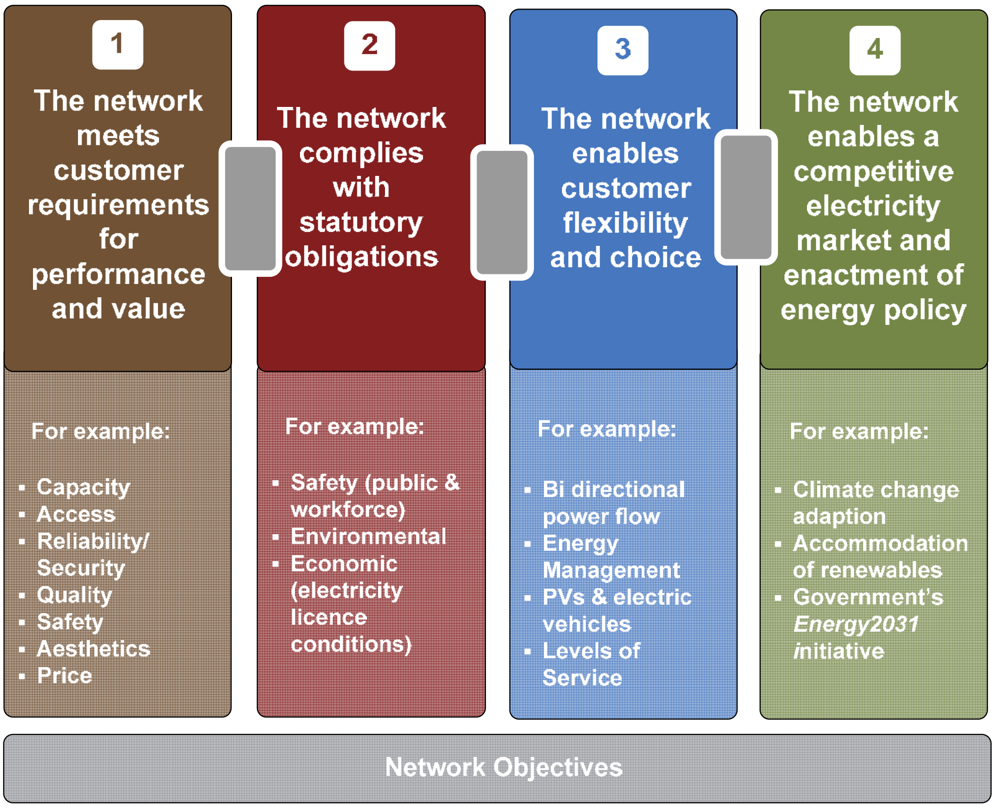

Figure 28: Network objectives

Network investment guiding principles

The network investment guiding principles provide a framework for making investment decisions where trade-offs between risk and performance are required.

Applying these principles supports transparent, commercially sound, economically efficient and sustainable investment in network and non-network solutions. It also provides increased assurance of regulatory compliance in the safety, environmental management and economic regulatory requirements (for example, where investments are required to satisfy efficiency tests in the Access Code). Figure 29 shows the network investment guiding principles.

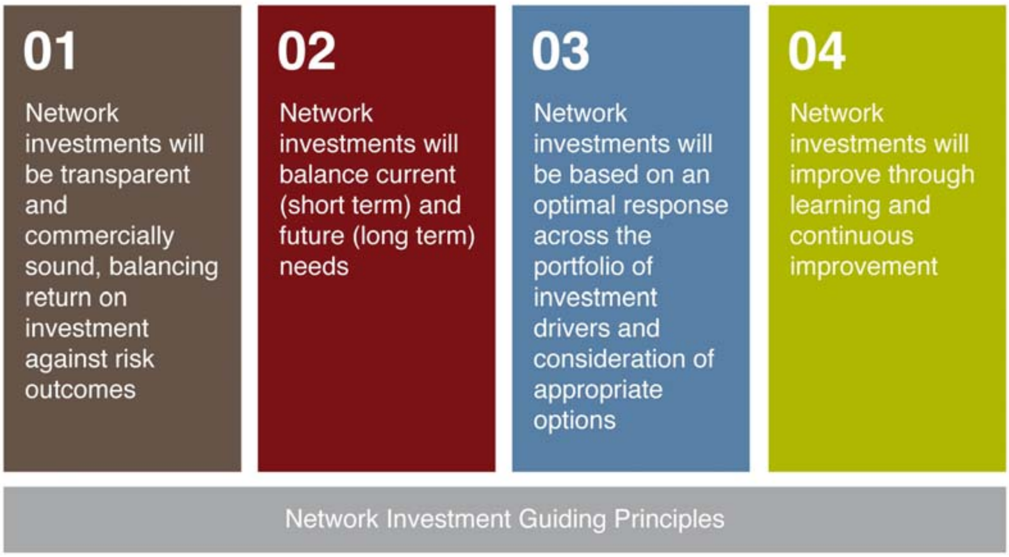

Figure 29: Network investment guiding principles

Network investment drivers

Network investment drivers are events, challenges or factors that influence the need for specific investment. These drivers are often variable and may impact the size or focus of the network investment required to meet the network objectives.

For example, a high volume of new connections would directly impact investment, as it would typically result in investment to ensure the network has sufficient capacity to allow them to connect without compromising the safety or security of the network.

Figure 30 shows the network investment drivers.

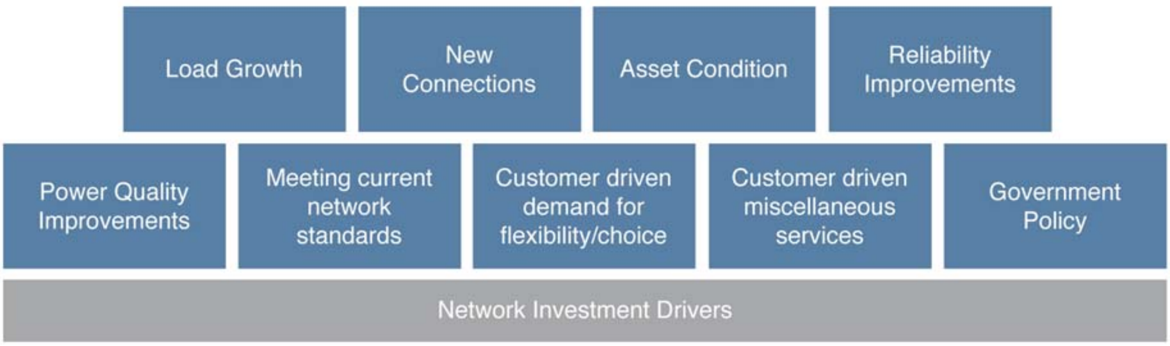

Figure 30: Network investment drivers

The strategy informs the Transmission Network Development Plan and Network Management Plan, ensuring all proposed investment is considered against a consistent suite of drivers, principles and objectives.

A copy of the Network Investment Strategy is attached at Appendix K.

4.3 Transmission Network Development Plan

The Transmission Network Development Plan is a ten-year outlook that provides guidance for decisions on major augmentations and new assets in the network. The plan contains a sequence of projects that represent least cost network investment to deliver on mandated service and supply standards over time. It is underpinned by the planning criteria specified in the Technical Rules administered by the Authority.

The Transmission Network Development Plan is drawn from the Network Investment Strategy and sits alongside the Network Management Plan (discussed in section 4.4) in the works planning and delivery system. It applies to all transmission growth capital and operating expenditure on the Western Power Network.

The plan considers a number of factors including generation forecasts, asset management plans, commercial objectives and load growth. It is refreshed annually to reflect changes to these factors and the development of more refined project definitions as part of the project development phase.

The plan includes initiatives to address current and forecast limitations on the transmission network, while also delivering (incremental) improvements to global network issues. These issues include better utilisation of the 330 kV network, improved load sharing among assets, minimisation of network losses, operational flexibility and enhanced system security.

When planning for the future, we undertake detailed system studies for a variety of load and generation scenarios based on the latest demand and customer number forecasts. We then select the option which represents the most economically efficient investment in the network.

In addition to the ten-year Transmission Network Development Plan, we also compile long-term (10-25 years) plans for each of the load areas[54] in the transmission network. The 10–25 year plans direct the work required to address the long-term issues of each load area in relation to the strategic network objectives for transmission system development.

The Transmission Network Development Plan also directly impacts distribution network planning. Due to the shorter-term nature of distribution planning, a period of up to five years is generally considered for the distribution network. This is because the distribution network can be quite dynamic and consists of a high number of relatively small projects that are often customer-driven. This can lead to multiple changes in plans, making it difficult to predict beyond a five-year timeframe.

A copy of the Transmission Network Development Plan is provided at Appendix O.

4.4 Network Management Plan

The Network Management Plan provides guidance on how and when to invest in assets to maximise performance and minimise asset life-cycle costs. The plan predominantly deals with in-service assets and considers asset condition, utilisation, technical compliance and replacement cycles. Importantly, it also demonstrates where reducing investment is likely to lead to higher costs over the life of the asset.

The plan informs the non-growth capital investment and operating expenditure that the business undertakes as a part of the approved works program. This includes asset replacement, regulatory compliance capital projects and routine and corrective maintenance programs. It also addresses the overlaps and dependencies with growth investment.

[54] The Western Power Network is separated into five geographic regions, which for the purposes of transmission planning, are further divided into 15 load areas. The load areas are defined, in general, by boundaries between major terminals and demand centres.

The Network Management Plan is guided by the Network Investment Strategy. The plan is informed by:

- the current state of the network as articulated via failure rates, age profiles and other indicators of asset condition
- asset strategies which describe the rationale behind how network assets are monitored, maintained and operated[55]
- good electricity industry practice and manufacturer specifications as captured in Western Power's network standards and work practice manual
- regulatory and legislative compliance obligations

It is reviewed and refreshed on an annual basis to allow for changes arising from industry practice, asset performance, engineering standards, asset strategies, network requirements and strategic developments within the business.

A copy of the Network Management Plan is provided at Appendix L.

4.5 Approved Works Program

The Approved Works Program (AWP) provides a five-year view of the projects, programs and activities for the network. It is refreshed annually and details the forecast capital and operating expenditure over the five financial years following the current year.

The AWP provides the most contemporary view of forecast expenditure as it is adjusted each year to reflect changing priorities and key parameters affecting programs. The AWP annual refresh is coordinated to align with the State Budget timeline and the creation of associated documents – the Strategic Development Plan and Statement of Corporate Intent, which are submitted to the Government.

It is essential that the business objectives, financial objectives and operational targets in the Strategic Development Plan and Statement of Corporate Intent reflect the approved State budget level of expenditure and funding. This ensures that there is no uncertainty with regards to the practical delivery of the AWP which is the key component of expenditure. The coordination of AWP with the Strategic Development Plan and the State budget ensures maximum certainty for effective internal planning and efficient delivery considerations.

This alignment of AWP and State budget ensures that the prioritisation of available funds is managed proactively, setting the business up for successful delivery of its highest priority network investment need.

4.5.1 Works program governance

At a tactical level, we use a works program model to guide capital and operating decisions for capital projects and maintenance programs. It provides a method of ensuring that projects identified through the planning process are managed effectively and efficiently.

The works program model is a gated framework based on the works program life cycle, which is a collection of sequential project phases common to all projects and programs. The model sets out the steps required to develop, design and deliver projects or programs and is characterised by a six-gate process as shown in Figure 31.

[55] For example, asset strategies articulate whether the asset is treated as 'run-to-failure' or 'replace on condition' and the number of years in an inspection cycle.

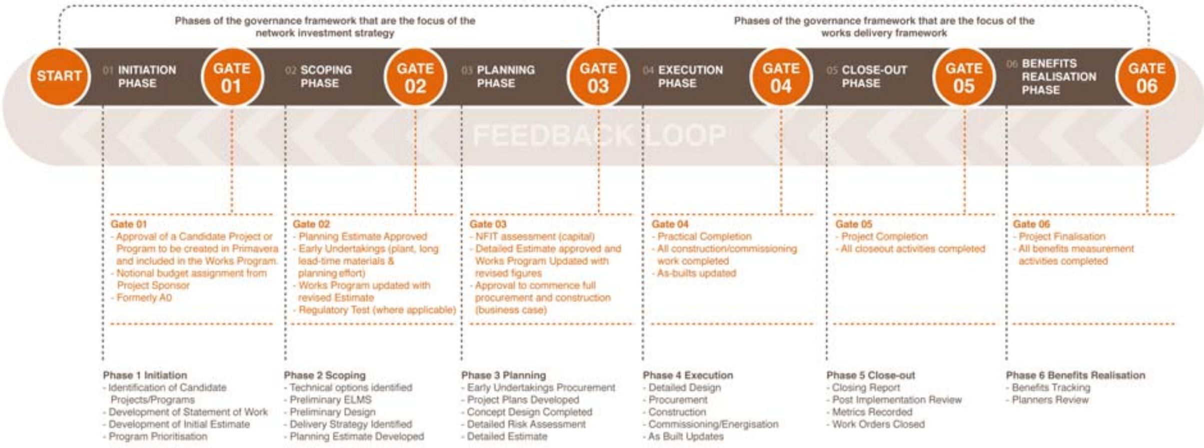

Figure 31: Works program model

The control gates ensure investment options and assessments are undertaken at the appropriate time and that they support the requirements of the Access Code in relation to new facilities investment. It includes requirements to comply with the NFIT at various stages of the works planning process, not just at the early planning stage.

Importantly, the model also requires review and assessment at project completion to capture lessons, confirm objectives have been met and ensure the contemporary information is fed back into the planning cycle.

Table 7 shows how Western Power's various processes and documents link to the works program model phases.

Table 7: Documents and process that relate to the works program model

Works program model phase	Relevant Western Power processes and documentation
Stage 1: Initiation Creates long term and short term views of all future projects within Western Power on an unconstrained basis to facilitate detailed and accurate planning and resource management.	• Network Investment Strategy • Transmission Network Development Plan • Network Management Plan • Load, generation, peak demand, customer numbers and energy forecasting • Planning criteria • Needs statements • Planning report • Risk management framework
Stage 2: Scoping Identifies and assesses the different solutions to address the need in an optimal timeframe (considering trade-offs and prioritisation) while achieving the lowest sustainable cost option.	• Options analysis • Capital investment/operating expenditure trade-off process • Early design and feasibility studies • Estimating processes • Regulatory test where applicable

<table>
<tr><th>Works program model phase</th><th>Relevant Western Power processes and documentation</th></tr>
<tr><td>Stage 3: Planning
Ensures an appropriate plan for the execution of the chosen solution by identifying, designing and scheduling the different project activities. This will include elements such as a strategy for least-cost labour and materials procurement, scheduling and sequencing.</td><td>• Project management plan
• Business case process (see section 4.5.2)
• Optimisation processes including smart planning and maintenance bundling
• Design and technical standards
• Design report
• New facilities investment test (where applicable)
• Works delivery strategy
• Estimating process
• Materials procurement
• Labour contracting
• Delegated financial authority
• Change control process</td></tr>
<tr><td>Stage 4: Execution
Ensures the project is delivered on time, within budget and to specification of the plan using rigorous cost, scope and timing controls and project management techniques.</td><td>• Project management plan
• Design and technical standards
• Works Practice Manual
• Materials procurement
• Labour contracting (including EBA)
• Change control process
• Quality assurance process</td></tr>
<tr><td>Stage 5 Close-out
Finalises all project activities and requires formal approval to ensure that the project costs are accurately documented and considers the long-term forecasts, change in load and sales, as well as economies of scale and scope that are available.</td><td>• Close-out report
• Review of implementation of previous processes and their effectiveness</td></tr>
<tr><td>Stage 6: Benefits realisation and feedback loop
Identifies and communicates the benefits realised and lessons learned to help facilitate the execution of future projects to ensure that these are documented and fed back into the business.</td><td>• Benefits report
• Quality assurance process
• Processes and inputs into process are updated as required</td></tr>
</table>

4.5.2 Business case process

The business case process is an integral part of investment governance. It provides a consistent and robust approach to ensure investment is required and efficient.

Business cases are developed for the individual projects or programs of work that form the AWP. The majority of business cases are for capital investment projects. Due to their recurrent nature, operating and maintenance programs are identified under the Network Management Plan and approved as part of the AWP.

The business case process is undertaken between gates 2 and 3 in the works program model. This ensures that prior to commencement of the execution phase:

- the investment need and objectives are defined
- all options are identified and addressed
- the appropriate option is selected considering:
    - risks
    - economic assessment
    - impact on customers
    - financial impact on Western Power
    - relationships between investment trade-offs
    - clear objectives are identified
- the selected option efficiently minimises costs

The process follows strict internal approval procedures under our delegated financial authority policy, with Board approval required for projects valued greater than $15 million.

For individual projects, the business case process considers the full life-cycle cost of the project. This is converted into an in-year budget through the annual AWP refresh process. Where any of the key assumptions included in the business case change during the life of the project, whether it is due to internal or external factors, a change control process (as mentioned in section 4.7 below) is followed. Change controls are done on an as needed basis, with the quarterly forecast process providing an opportunity to present them in a revised AWP forecast view for the period.

4.6 Works Delivery Strategy

The Works Delivery Strategy sets out how we deliver network investment efficiently and in line with what is proposed at the planning stage. It describes the activities we undertake to ensure:

- safe project execution and operation
- compliance with network reliability and quality standards
- compliance with environmental standards
- compliance to Western Power standards and work practices that align to good electricity industry practice

The Works Delivery Strategy is a key component of the planning, asset management and delivery system. It informs the Network Investment Strategy and the plans that are drawn out of it, by providing visibility of Western Power's delivery capability in the medium-to-long term. It ensures there is an appropriate balance between the network investment that is required and the time frame over which it can be delivered. Similarly, the strategy is informed by the long-term asset management and development plans to ensure an efficient level of resourcing is maintained.

The Works Delivery Strategy objectives are:

- **efficient delivery** – maximising competition between external suppliers and fine-tuning internal processes to ensure the delivery method is efficient
- **deliverability** – ensuring that the optimal mix of labour, materials and fleet is available so that the program will be delivered

- **maintaining an in-house emergency response capability** – we will retain a level of internal resource that can be mobilised quickly to respond to emergencies and ensure rapid fault restoration
- **building and retaining in house expertise –** we will develop and retain visibility and control of the works delivery program in-house to enable us to scope projects and manage contracts effectively

The cornerstone of the Works Delivery Strategy is the balanced portfolio. The balanced portfolio is the suite of internal and external resources available to deliver the works program. The portfolio includes a diverse mix of external contractors and preferred vendors, which we manage using a range of contracting arrangements including performance-based contracts, standard contracts and an alliance arrangement. These are complemented by our operational staff. Table 8 summarises the external delivery channels.

Table 8: Summary of external delivery channels

Delivery channels	Description
Alliance	Alliance contracting is where two or more parties focus on working together to achieve common outcomes as a single entity (in virtual or legal terms). We use alliance contracting for high risk programs or projects where we wish to maintain a high level of control. It also allows us to leverage off the skills and expertise of other organisations while sharing the benefits of improved efficiencies with customers. The customer funded distribution program is an example of work delivered through alliance contracting. This work stream provides consistency of work flow ensuring alliance labour resources are optimally utilised. Alliance delivery provides customer focus and priority while asset driven programs are delivered by other delivery channels.
Performance based contracts	Performance based contracting is a relationship-based model which facilitates the joint achievement of outcomes and the sharing of efficiencies. The parties operate as separate entities, bound by traditional contractual arrangements. Key performance indicators drive quality and efficiency. We have three major national service providers engaged under this form of contract. These major contractors deliver distribution preventative maintenance, asset replacement and growth-driven programs. They were appointed following an extensive tender process and benchmarking of east-coast distribution network operators.
Standard contract	We use standard contracts such as AS4000 design and construct for projects where outcomes are specified, for example the construction of a new substation. In such cases the asset will have been designed to a certain specification and the work is put out to tender. Using the standard contract as a base, we then work with the contractors to negotiate where delivery risk should be allocated and secure the most efficient price.
Preferred vendor	We use preferred vendors for non-strategic work or for specialist tasks that may not warrant the establishment of a deeper relationship. To ensure the most efficient engagement of this market, we have established a panel of preferred suppliers or vendors with pre-negotiated schedule of rates based on a broad scope of requirements.

The balanced portfolio provides the following benefits:

- **increased efficiency through competition** – the balanced portfolio facilitates benchmarking across the delivery channels and competitive prices for materials and labour. It enables efficiencies to be pursued in terms of price and quality

- **ability to efficiently scale resources up or down** – we are able to provide visibility of likely work volumes to external contractors, encouraging efficient investment in capacity and capability (people and fleet)

Figure 32 demonstrates the inherent flexibility in the balanced portfolio.

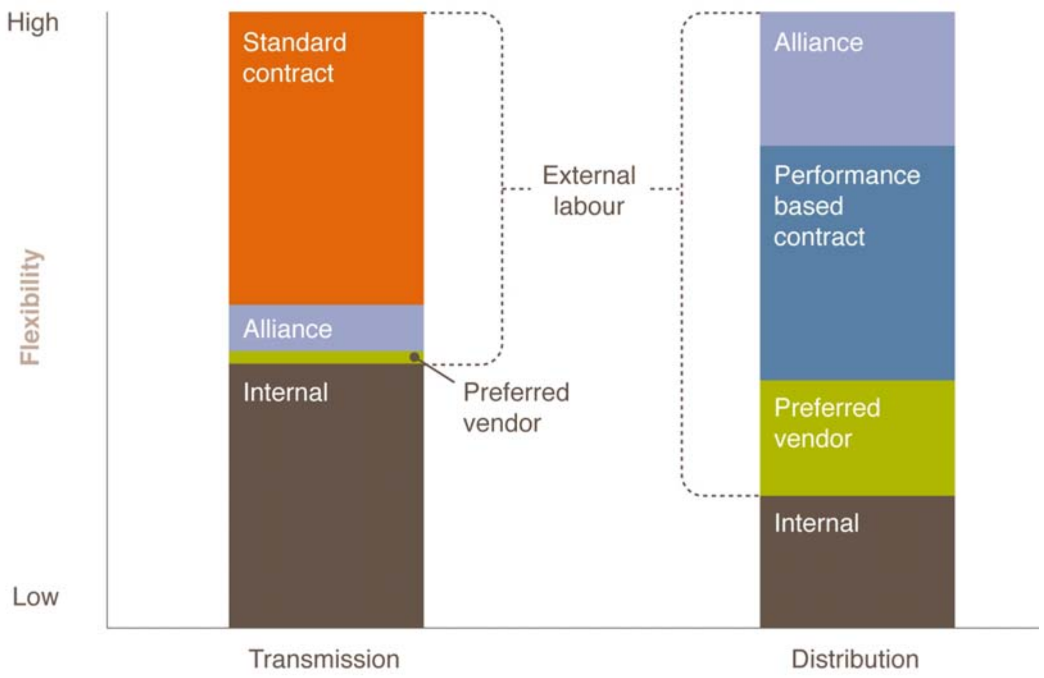

Figure 32: Delivery channel flexibility

The Works Delivery Strategy sets out in detail how we use the balanced portfolio and procurement processes to ensure efficient delivery of the planned work program. To ensure we retain sufficient control over delivery the following activities are performed by internal resources where appropriate:

- program, project and contract management
- work planning and scheduling
- procuring materials competitively
- design and commission
- selected maintenance work
- ensuring essential services such as safe and timely emergency response and supply restoration

Retaining control and visibility of these functions allows the business to constantly evaluate delivery capability and performance, ensuring planned work can be delivered in full and at an efficient cost.

A copy of our Works Delivery Strategy is provided at Appendix M.

4.7 Monitoring and review

The long-term planning, asset management and works delivery processes and functions are closely monitored on a periodic basis. We analyse and report on the detailed project and program view of the investment portfolio so that the most proactive, efficient and timely business decisions can be made in response to any changes, challenges or opportunities presented.

Periodic review

The Network Investment Strategy, Transmission Network Development Plan, Network Management Plan, Approved Works Program and Works Delivery Strategy are all subjected to rigorous internal review, culminating in Board approval and sign-off when any material changes are made. Each of these documents is refreshed annually to test consistency with each other and assess any variance from the works program.

This is all managed in line with annual planning cycle calendar, which ensures that there is alignment between branches and divisions and improved consistency in how we plan and schedules programs of work.

Our progress against forecast is monitored regularly and supported by ongoing change control process for individual projects and programs. Any identified change in expenditure profile, scope, schedule or cost is documented, explained and justified and approval for the change is sought. The change control process is managed in line with our delegated financial authority policy.

Project and program sponsors are responsible for ensuring that all proposed transmission and distribution network projects are justified in terms of the criteria and principles set out in the Network Investment Strategy, which includes the requirements of the new facilities investment test.

There is also a comprehensive monthly business report which considers the progress towards achievement of the AWP. This provides an early signal to the business for any potential opportunities, challenges or amendments to the planned work for the given period.

Utilising project management software

Planning and works program management and reporting are further enhanced by the use of advanced project management software. The Enhanced Planning and Works Management project was launched in 2009. This project involves the implementation of the Primavera suite of software, which is being used for project, program and portfolio management within the works program. The business has implemented Primavera as its modelling tool for transmission capital projects, with full implementation expected before the end of 2011/12.

The software facilitates enterprise wide project planning, management and control. It enables budget and deadline commitments to be met by managing schedules, resources and costs. The AWP is stored and managed in a structure that allows flexible reporting of financials, progress and resourcing.

Audit and quality assurance

Audit and quality assurance is also a feature of our planning, asset management and works delivery system. As part of our assurance framework the Board approves an annual audit plan, which details the specific business areas subject to internal audit during that financial year. Areas of focus are selected based on business impact, timeliness and materiality and vary from year to year.

Below is a sample of the audits conducted during 2010/11:

- data integrity
- corporate strategy
- management of operational safety risks
- vegetation management
- internal assessment of working practices in the field
- review of project management for transmission and distribution projects

In addition, the following external audits were conducted:

- review of asset data management
- review of safety practices
- surveillance audit of the Network Operations Branch's compliance to AS/NZS ISO 9001:2000
- organisational culture inventory survey
- financial audits of alliance arrangement contract

These corporate level reviews are complemented by regular audits at a divisional level. For example, internal review of the asset management system is conducted every 24 months, as well as an audit by an independent auditor. This is designed to support the Authority's audit of Western Power's asset management process, ensuring all recommendations are captured, implemented and assessed prior to the next audit cycle.

PART B: INVESTMENT PROPOSAL

5 Service and standards

This chapter discusses Western Power's services and service standards proposed for AA3. It outlines a number of changes proposed to the services, service standard benchmarks and service standards adjustment mechanism, which are designed to better meet customers' needs and the Access Code objectives and requirements.

This chapter:

- outlines the services to be delivered in AA3
- provides an overview of the service standard framework
- identifies the service performance measures that characterise the services we deliver to our customers
- outlines the level of service to be provided over the AA3 period
- provides an overview of the reporting, legal obligations and financial incentives that will support the delivery of services

An overview of how this chapter meets the requirements of the AAI Guidelines is included in section 5.8.

5.1 Key messages

- We will provide 17 reference services in AA3.
- We will retain the reference services A1 to A11 (exit services) and B1 to B2 (entry services) as they continue to be sought by a significant number of network users and applicants.
- We will alter the definition of the existing bi-directional reference service (C1) and add three new bi-directional reference services (C2 to C4) in response to the growth in photovoltaic (PV) systems.
- We will clarify the circumstances under which a customer receives a non-reference service.
- We propose enhancements to the service standard framework, which will improve the effectiveness of the incentives, increase value to customers and address inconsistencies in the current model. In summary:
    - we will invest to maintain a level of service performance during AA3 that is consistent with the average service level experienced by customers over the last five years
    - we have aligned the incentives for service improvements with a proxy for the value that our customers place on those improvements
    - we will only invest to improve service where the cost of the improvements are less than the value to customers and we will not recover revenue for that investment until AA4
    - there will be stronger, balanced incentives to drive cost efficiencies without compromising the standard of service to customers
    - service standard benchmarks will reflect the service standard for the reference services rather than for network performance

- we will continue to report on our service performance measures to ensure we effectively monitor and manage performance over the period

The detail of the changes to services and the service standard framework and the rationale for these changes is discussed in the following sections.

5.2 Services

We will continue to provide reference services and non-reference services during AA3. We will continue to not provide any excluded services, unless a determination is made by the Authority to declare a service as an excluded service under sections 6.33 to 6.37 of the Access Code.

Access Code provisions

Western Power provides covered services that are regulated through an access arrangement. The Access Code defines a **covered service** as:

> *a service provided by means of a covered network, including:*
> *a) a connection service; or*
> *b) an entry service or exit service; or*
> *c) a network use of system service; or*
> *d) a common service; or*
> *e) a service ancillary to a service listed in paragraphs (a) to (d) above,*
> *but does not include an excluded service.*

A covered service can be either a reference service or a non-reference service.

A **reference service** is defined as**:**

> *a covered service designated as a reference service in an access arrangement under section 5.1(a) for which there is a reference tariff, a standard access contract and service standard benchmarks.*

A **non-reference service** is defined as:

> *a covered service that is not a reference service.*

An **excluded service** is one which is declared as an excluded service under sections 6.33 or 6.35 of the Access Code. To meet the Access Code requirements of an excluded service, the service must face sufficient competition and the cost of the service is able to be excluded for price control purposes.

5.2.1 Reference services

We will provide 17 reference services in AA3. The 14 reference services provided in AA2 will be retained, with a modification to the existing bi-directional reference service. Three new bi-directional services will be added.

We will provide three broad categories of reference services during AA3:

1. **Distribution reference services** – most of our customers are connected to the distribution network and receive a distribution reference service. Their reference service is influenced by the performance of the distribution network and the transmission network. The costs are included in the distribution and transmission revenue caps.
2. **Transmission reference services** – a small number of large customers and generators are connected to the transmission network and receive a transmission reference service. Their reference service is influenced by the performance of the transmission network only and the costs are included in the transmission revenue cap only.
3. **Street lighting reference services** – we operate and maintain streetlights, as well as provide network access for the streetlights. The costs are included in the distribution **and** transmission revenue caps.

The bi-directional reference services are a type of distribution reference service. We are making changes to the bi-directional reference services in response to the rising demand from customers for these services, driven primarily by the increasing number of roof-top photovoltaic (PV) systems.

In 2010, we received more than 20,000 applications for the installation of PV systems at residential properties, taking the total number of properties with PV to more than of 37,000. We currently receive between 2,000 and 3,000 applications per month.

Despite the recent suspension of the feed-in tariff scheme for residential customers[56], the high consumer demand for PV systems is expected to continue as the cost of PV systems declines.

The feed-in tariff scheme did not apply to non-residential customers. Therefore the suspension of the scheme does not affect the growing demand for PV systems from businesses and industry.

The new bi-directional reference services for AA3 are the outcome of a recent review of our bi-directional services and tariffs. The objectives of the review were to:

- address the emerging need for a bi-directional reference service for commercial premises with on-site generation
- address implementation issues faced by Synergy that led to the bi-directional reference service introduced in AA2 (to cater for residential premises with small generators) not being taken up

The review incorporated consultation with major stakeholders including the Office of Energy, Synergy and other retailers. Further information regarding the process, analysis and outcomes of the review can be found in Appendix Z: Ernst & Young report - bi-directional tariff reference services and associated tariffs.

Table 9 provides a full list of the reference services we will provide in AA3.

Table 9: List of reference services for AA3

Reference service	Reference service description	Category of reference service	Revenue cap recovery (Tx – transmission Dx – distribution)	Retained from AA2 or new or changed in AA3
A1	Anytime energy (residential) exit service	Distribution	Tx and Dx	Retained from AA2
A2	Anytime energy (business) exit service	Distribution	Tx and Dx	Retained from AA2
A3	Time of use energy (residential) exit service	Distribution	Tx and Dx	Retained from AA2
A4	Time of use energy (business) exit service	Distribution	Tx and Dx	Retained from AA2
A5	High voltage metered demand exit service	Distribution	Tx and Dx	Retained from AA2
A6	Low voltage metered demand exit service	Distribution	Tx and Dx	Retained from AA2
A7	High voltage contract maximum demand exit service	Distribution	Tx and Dx	Retained from AA2

[56] The feed-in tariff scheme reached its quota and was suspended on 1 August 2011.

Reference service	Reference service description	Category of reference service	Revenue cap recovery (Tx – transmission Dx – distribution)	Retained from AA2 or new or changed in AA3
A8	Low voltage contract maximum demand exit service	Distribution	Tx and Dx	Retained from AA2
A9	Street lighting exit service	Street lighting	Tx and Dx (includes streetlight operating and maintenance costs)	Retained from AA2
A10	Unmetered supplies exit service	Distribution	Tx and Dx	Retained from AA2
A11	Transmission exit service	Transmission	Tx	Retained from AA2
B1	Distribution entry service	Distribution	Tx and Dx	Retained from AA2
B2	Transmission entry service	Transmission	Tx	Retained from AA2
C1	Anytime energy (residential) bi-directional service	Distribution	Tx and Dx	Changed for AA3
C2	Anytime energy (business) bi-directional service	Distribution	Tx and Dx	New for AA3
C3	Time of use (residential) bi-directional service	Distribution	Tx and Dx	New for AA3
C4	Time of use (business) bi-directional service	Distribution	Tx and Dx	New for AA3

Further detail on our reference services for AA3 is provided in Appendix E: Reference services of the access arrangement.

5.2.2 Non-reference services

We will continue to provide a range of non-reference services during AA3 in response to customer requirements for:

- network access services that are not reference services (for example Ninga Mia[57])
- miscellaneous services that are ancillary to the conveyance of electricity by means of the Western Power Network (for example the lifting of electrical wires to allow high loads to pass down highways)[58]

Consistent with section 2.8(b) of the Access Code, we negotiate in good faith the commercial terms and conditions, including price, around the provision of non-reference services with the user or applicant.

[57] Ninga Mia is an Aboriginal community near Kalgoorlie-Boulder with a direct retail arrangement with each premise through the installation of pre-payment meters that allow households to manage their electricity consumption individually.

[58] Miscellaneous non-reference services are restricted to operating expenditure services (such as extended metering services) and exclude work that is capitalised.

From time to time, Western Power connects large generation or load where an exemption from the Technical Rules[59] has been agreed by the customer, or where a different service level, contract and tariff from the service standard benchmark, electricity transfer access contract and reference tariff respectively has been agreed.

For ease of administration and with the customer's agreement, we have to date treated the related service as a reference service. However, we will revise this approach for AA3.

We propose that where the customer has been granted an exemption from the Technical Rules under section 12.34 of the Access Code the service will be a non-reference service. We will revise Appendix E: Reference services of the access arrangement to make this clear for our benefit and the benefit of our customers.

Customers will see little practical difference. In fact the circumstances described are currently the subject of negotiation between the parties as if the services were non-reference services. These revisions simply make the terminology and concepts used consistent with the requirements of the Code. There is no change to a customer's access rights; under either a reference or non-reference service, where we do not provide the service sought, the customer has equivalent rights to seek resolution by way of arbitration.

5.2.3 Excluded services

As in AA2, we will not provide any excluded services in AA3.

The Authority has not, to date, made a determination to declare a service as an excluded service under sections 6.33 to 6.37 of the Access Code.

We do not intend to seek a determination of excluded services pursuant to section 6.35 of the Code. However, we may at any time request that one or more services provided through the Western Power Network be declared excluded services by the Authority under section 6.33 of the Access Code.

5.3 Service standard framework

The service standard framework is designed to establish the levels of service that customers should receive and ensure that the incentives to achieve cost efficiencies under incentive-based regulation do not lead to any deterioration in service levels.

The service standard framework:

- clearly articulates the characteristics and level of service that customers should receive
- requires Western Power to report on a range of performance measures – this includes public reporting of performance against service measures and allows customers to compare Western Power's level of service over time and with its peers
- requires Western Power to deliver at least a minimum level of service to all customers – this is the minimum level of service that customers can expect to receive for a reference service at the reference tariff. Each reference service must have a prescribed minimum standard (the service standard benchmark)
- provides Western Power with financial penalties or rewards for deterioration or improvement (respectively) in service. These financial incentives include a guaranteed service level payments scheme and the service standards adjustment

[59] 'Technical Rules' are the Technical Rules for the network proposed by the network service provider (Western Power) and approved by the Economic Regulation Authority under chapter 12 of the Access Code.

mechanism (SSAM). The guaranteed service level payments scheme requires Western Power to make payments to customers for failure to meet certain service standards such as notification of planned outages or for long duration outages. The SSAM provides a financial incentive to improve or maintain performance against those measures valued by customers. The business is financially rewarded for delivering performance better than target and penalised for delivering performance worse than target

The performance measures included in the service standard framework typically include:

- **reliability of supply**, which is concerned with the duration and frequency of interruptions experienced by customers
- **security of supply**, which is concerned with the ability of the network to withstand events without interrupting supply to customers
- **quality of supply**, which is concerned with the characteristics of the electricity supply, such as short term or transient voltage increases (voltage surges) or reductions (voltage sags), voltage flicker or harmonic distortions
- **customer service**, which relates to meeting customer requirements including call centre performance, timely customer connections, timely response to enquiries and complaints, timely repair of faulty streetlights and notification of planned interruptions

We have a comprehensive range of performance measures to be able to manage our business on a daily basis.

Almost 200 of these performance measures are incorporated in the service standard framework. The framework is prescribed by a range of legal instruments, including the access arrangement. Table 10 summarises our service-related legal obligations.

Table 10: Western Power's service-related legal obligations

Performance measure		Legal obligations
Reporting on service measures		The Authority's performance reporting requirements, which reference: *Code of Conduct for the Supply of Electricity for Small Use Customers 2008* (customer connections, complaints, compensation payments, timely repair of streetlights and call centre performance) *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (network reliability and power quality, complaints and compensation payments) *Standing Committee on National Regulatory Reporting Requirements* (SCNRRR) (network reliability, complaints and network and asset information)
Minimum service standards		Access Arrangement – **Service Standard Benchmarks** *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* *Code of Conduct for the Supply of Electricity for Small Use Customers 2008*
Financial incentives	Service incentive scheme	Access Arrangement – **Service standards adjustment mechanism (SSAM)**

Performance measure		Legal obligations
	Guaranteed service level payments	*Electricity Industry (Network Quality and Reliability of Supply) Code 2005* *Code of Conduct for the Supply of Electricity for Small Use Customers 2008*

The service standard benchmarks and service standards adjustment mechanism are the elements of the service standard framework that are included in the access arrangement. In this access arrangement revisions submission, we have an opportunity to enhance these elements in order to enhance the overall service standard framework for AA3. Revisions to the service standard benchmarks are discussed in section 5.5 and the revisions to the service standards adjustment mechanism are discussed in section 5.6 of this document.

Access Code provisions

Section 5.1

An access arrangement must:

…

c) include service standard benchmarks under section 5.6 for each reference service

Section 5.6

A service standard benchmark for a reference service must be:

a) reasonable; and

b) sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff.

Section 11.1

A service provider must provide reference services at a service standard at least equivalent to the service standard benchmarks set out in the access arrangement and must provide non-reference services to a service standard at least equivalent to the service standard in the access contract.

Section 6.26

An above-benchmark surplus does not exist to the extent that a service provider achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks during the previous access arrangement period by failing to comply with section 11.1.

Section 6.30

An access arrangement must contain a service standards adjustment mechanism.

Section 6.29

A "service standards adjustment mechanism" is a mechanism in an access arrangement detailing how the service provider's performance during the access arrangement period against the service standard benchmarks is to be treated by the Authority at the next access arrangement review.

Section 6.31

A service standards adjustment mechanism must be:

a) sufficiently detailed and complete to enable the Authority to apply the service standards adjustment mechanism at the next access arrangement review; and

b) consistent with the Code objective.

Section 11.2

The Authority must monitor and, at least once each year, publish a service provider's actual service standard performance against the service standard benchmarks.

5.4 Reporting on service measures

Public reporting is one of the most critical aspects of the service standard framework. Throughout AA3 we will continue to report publicly on performance measures in our quarterly and annual reports and on the performance measures that are specified in the Authority's Electricity Compliance Reporting Manual. We will also continue to report on the performance measures that were service standard benchmarks in AA2 but will not be service standard benchmarks in AA3.

Our internal reporting framework consists of thousands of measures that monitor all aspects of our business. We monitor our performance against these measures on a daily basis at the operational level and on a monthly basis at the Executive and Board level.

We track how our performance is changing over time. We identify systemic issues and take action where required to ensure that our service levels continue to be on target.

We publish the following reports on our website:

- **quarterly reports** – which provide an overview of our performance during the quarter against the key performance indicators that are in our Statement of Corporate Intent[60]
- **annual reports** – which provide an overview of our financial and operational performance for the year, including performance against the indicators in our Statement of Corporate Intent
- **service standard performance reports** – which provide an overview of our performance against key performance indicators detailed in our access arrangement to the Authority. The Authority also publishes this report on its website to fulfil its obligations under section 11.2 of the Access Code

We are also required to publicly report on some of our performance measures through:

- **an annual reliability and power quality report** – which provides information required as part of Schedule 1 of the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* and is published on our website
- **the Authority's annual performance report** – which reports on the performance information we provide to the Authority, in accordance with the Authority's *Electricity Compliance Reporting Manual* and is published on the Authority's website

The Electricity Compliance Reporting Manual combines the reporting requirements that are set out in the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* and the *Code of Conduct for the Supply of Electricity to Small Use Customers 2008*. The *Electricity Compliance Reporting Manual* sets out measures for:

- customer connections (3 measures)
- network reliability (74 measures)
- complaints (28 measures)
- compensation payments (3 measures)
- timely repair of faulty streetlights (8 measures)
- call centre performance (5 measures)

[60] The Statement of Corporate Intent is a one-year plan for the business agreed with State Government, which incorporates the business objectives and performance targets for the year. It is tabled in Parliament and made public.

- network and asset information (84 measures)

Some of the network reliability measures we report on are aligned with the Standing Committee on National Regulatory Reporting Requirements (SCNRRR) definitions which are commonly used by Australian electricity utilities. This enables comparison of our performance with utilities in other jurisdictions.

5.5 Minimum service standards for AA3

We will have service standard benchmarks for each reference service in AA3. We will reduce the number of service standard benchmarks and revise the level at which the service standard benchmark is set, to represent a minimum level of service that we expect to be able to provide to our customers.[61]

Section 5.1 of the Access Code requires that an access arrangement must contain service standard benchmarks for each reference service. Section 11.1 of the Access Code has the effect that the service standard benchmarks are minimum service standards:

> *A service provider must provide reference services at a service standard at least equivalent to the service provider's service standard benchmarks set out in the access arrangement and must provide non-reference services to a service standard at least equivalent to the service standard in the access contract.*

Through our licences, we have a legal obligation to meet these service standard benchmarks.

Clause 6.26 of the Access Code also provides a link between the service standard benchmarks and the gain sharing mechanism. Our access arrangement states that we forego any rewards under the gain sharing mechanism for efficiency improvements if all the service standard benchmarks are not met.

As explained below, during AA2 the service standard benchmarks measured the performance of our transmission and distribution networks instead of relating directly to reference services. During AA3 the service standard benchmarks will be directly related to the reference services, therefore better satisfying the Access Code requirements.

Licence obligations

Section 5.1 of the Transmission Licence and of the Distribution Licence states that:

> *Subject to any modifications or exemptions granted pursuant to the Act, the licensee must comply with any applicable legislation.*

Applicable legislation is defined as:

> *(a) the Act; and*
>
> *(b) the Regulations and Codes that apply to the licensee.*

The definition of Codes includes the *Electricity Networks Access Code 2004*.

In addition, by setting the service standard benchmarks at a level that we expect to achieve most of the time, we increase the likelihood of complying with our licence. We also increase the likelihood of accessing additional rewards for cost efficiencies under the gain sharing mechanism. Stronger cost efficiency incentives will benefit customers in subsequent regulatory periods as the cost of providing services is reduced.

The changes to the service standard benchmarks for AA3 are explained in sections 5.5.1 and 5.5.2.

[61] Note that the setting of the service standard benchmark at a level consistent with minimum service **will not** mean service levels will deteriorate. This is explained in section 5.5.2 of this chapter.

5.5.1 Establishing customer-focused performance measures

We established criteria for assessing which performance measures should be adopted as service standard benchmarks for each reference service for AA3. We assessed whether they were necessary to reflect value to the customers for each reference service. Our objective was to ensure that we had no more service standard benchmarks than necessary, given the legal and financial implications associated with service standard benchmarks.

The criteria established to assess the merits of particular performance measures were:

a) performance measures must reflect the nature of the reference service

b) performance measures should reflect aspects of service most valued by customers

c) each performance measure can be set as a minimum service standard

d) good quality data must be available (it must be measurable, reliable, verifiable and there needs to be reasonable historical data)

e) a performance measure must be included if there is an obligation in a legislative or regulatory instrument that requires it

f) the measure reflects the outcome of investment that will occur during AA3

g) the outcome cannot be distorted

h) the measure is independent of other measures

The service standard benchmarks for AA2 cover reliability of supply (based on network performance rather than reference service), security of supply and timely repair of street lighting. We assessed these existing measures against the criteria as well as other measures.

For AA3, we will:

- include performance measures that are directly related to reference services
- remove performance measures that are not directly related to reference services
- remove performance measures that unnecessarily duplicate other measures, or relate to services or outcomes that customers do not value
- introduce customer service performance measures for distribution and transmission reference services, as these are valued by customers

Table 11 identifies the service standard benchmarks that will be retained from AA2 to AA3, those that will be amended from AA2 to AA3, the new service standard benchmarks and the AA2 service standard benchmarks that will not be retained.

We are in the unique position of being an integrated transmission and distribution network services provider. Other transmission utilities mainly provide service to distribution utilities. In turn, the service provided by stand-alone distribution utilities is affected by the performance of the transmission utility, which they cannot control.

We control both the distribution and the transmission networks. We therefore can and should operate both networks to improve the customers' service experience. As a result it is also appropriate that we have different transmission performance measures to stand-alone transmission utilities in Australia. This difference is reflected in the service standard benchmarks for AA3.

Table 11: Service standard benchmarks in AA2 and AA3

AA2 service standard benchmarks	AA3 service standard benchmarks
Distribution network 1. Unplanned SAIDI[62] CBD 2. Unplanned SAIDI urban 3. Unplanned SAIDI rural short 4. Unplanned SAIDI rural long 5. Unplanned SAIDI SWIN total* 6. Unplanned SAIFI[63] CBD 7. Unplanned SAIFI urban 8. Unplanned SAIFI rural short 9. Unplanned SAIFI rural long 10. Unplanned SAIFI SWIN total* **Transmission network** 11. Circuit availability 12. System minutes interrupted - meshed network* 13. System minutes interrupted - radial network* 14. Loss of supply event frequency >0.1 system minutes* 15. Loss of supply event frequency >1 system minutes* 16. Average outage duration* **Street lighting** 17. Repair times Perth Metropolitan area# 18. Repair times major regional towns# 19. Repair times remote and rural towns * removed for AA3 # revised for AA3	**Distribution reference services** 1. Unplanned SAIDI CBD† 2. Unplanned SAIDI urban† 3. Unplanned SAIDI rural short† 4. Unplanned SAIDI rural long† 5. Unplanned SAIFI CBD† 6. Unplanned SAIFI urban† 7. Unplanned SAIFI rural short † 8. Unplanned SAIFI rural long † 9. Call centre response** **Transmission reference services** 10. Individual customer service measure **Distribution and transmission reference services** 11. Circuit availability **Street lighting reference services** 12. Repair times metropolitan areas** 13. Repair times regional areas † revised for AA3 to include transmission outages **new/revised measures for AA3

We will continue to report publicly during AA3 on the AA2 service standard benchmarks that are not being retained. This will provide an incentive to perform at a level consistent with our peers.

The following sections discuss the rationale for the revisions to the performance measures. The full definition of the proposed performance measures, as required by the AAI Guidelines, is included in the access arrangement.

5.5.1.1 Performance measures for distribution reference services

We have retained all but two of the service standard benchmarks for distribution reference services for AA3. In addition, we have modified the definition of SAIDI and SAIFI and added a new customer service measure.

[62] System average interruption duration index – the average minutes off supply.
[63] System average interruption frequency index – the average number of interruptions

The 'SWIN total' SAIDI and SAIFI measures have been removed from the AA3 suite of service standard benchmarks because they measure reliability across the whole of the network. We already have benchmarks that measure performance by feeder category (CBD, urban, rural short, rural long)[64] so there is no need for an additional 'whole of network' measure. We also believe that performance by feeder type is valued more highly than a total measure, as it better reflects customers' service experience. However, while 'SWIN total' is not included in the service standard benchmarks, we will continue to report publicly on reliability across the whole of the network, as required by the Authority's *Electricity Compliance Reporting Manual*.

The SAIDI and SAIFI measures used in AA2 will be modified for AA3 to include distribution **and transmission** interruptions experienced by distribution-connected customers. During AA2, SAIDI and SAIFI only measured the interruptions on the distribution network. Interruptions on the transmission network were excluded even when these events were within our control.

Including transmission outages in these reliability measures will provide a better representation of the customer's actual experience of the service we provide. Distribution-connected customers pay for a reference service to transport electricity on the transmission network and the distribution network. A customer cannot distinguish whether interruptions are on the transmission or distribution network, therefore it is appropriate to include interruptions on both networks in the measure.

We are including a specific customer service measure in the AA3 suite of service standard benchmarks. A customer preferences survey conducted in October 2010[65] indicated that our distribution customers are generally more accepting of supply interruptions if they are able to get timely information from the call centre. Customers pay for us to maintain and operate our call centre through reference tariffs and we are committed to improving our customer service, including call centre performance over time. Including this type of measure as a service standard benchmark is consistent with the approach adopted by the AER (and previously by state-based regulators).

The measure will be the proportion of telephone calls answered within 30 seconds and will include those calls answered by an operator or by an interactive voice response system, where substantive information is provided to the customer.

We will not include a quality of supply measure as a service standard benchmark. Quality of supply is currently measured on the basis of a small sample of localised, dedicated power quality meters only. Unlike reliability of supply, there are no broad indicators of power quality across the network. Additionally there are already minimum standards for quality of supply in the Technical Rules[66].

During the stakeholder engagements that informed this revisions submission, customers indicated that they would value Western Power reducing the number of momentary interruptions[67], as even an instantaneous break in electricity supply can lead to machinery having to be reset, significantly disrupting productivity.

We have listened to this feedback and are taking action to reduce the number of momentary interruptions, however, we do not currently have sufficient data to include a measure of momentary interruptions as a service standard benchmark. We will seek to improve monitoring of momentary interruptions during AA3, so that we will be in a stronger position to consider their inclusion as a service standard benchmark for AA4.

[64] The feeder category definitions are consistent with the SCNRRR definitions.
[65] KPMG customer preferences for supply reliability report March 2011 based on survey conducted in October 2010.
[66] Clause 2.3 of the Technical Rules approved by the Authority under chapter 12 of the Access Code.
[67] A momentary interruption is an interruption of less than 1 minute.

5.5.1.2 Performance measures for transmission reference services

We have included a new customer-focused service standard benchmark for transmission reference services. We have then removed the AA2 service standard benchmarks that related to transmission network performance and did not reflect the service that individual transmission-connected customers actually experience.

We have a relatively small number of transmission-connected customers.[68] We recognise that they expect a more customised and responsive level of service than most distribution-connected customers.

The new customer-focused performance measure for AA3 provides a strong incentive for Western Power to provide high-quality customer service to these customers. The new measure requires that each transmission-connected customer has:

- **an account manager** – providing a direct point of contact in Western Power
- **an annually reviewed customer service management plan** – which reflects the individual needs of the customer
- **the opportunity to participate in an annual customer satisfaction survey** – providing an opportunity for customers to provide their feedback to us and enable measurement of each customer's service experience

Initially, the measure will simply be that each transmission-connected customer has each of these elements. If they do not, then in addition to us being potentially non-compliant with our licence, we will forego any rewards under the gain sharing mechanism for efficiency improvements.

We tested the new customer service measure with our transmission-connected customers and they are supportive. Feedback shows they would support a more customised measure and reporting for individual customers. They would be particularly interested in being able to set a scaled benchmark level for the customer satisfaction survey.

There is the potential in future access arrangement periods for a qualitative customer service measure to be included as a service standard benchmark, however this is not feasible for AA3 as we have insufficient historical data to allow an appropriate target to be set. We will collect data during AA3 that may allow the performance measure to be enhanced for AA4.

We considered a number of different reliability measures that could be included as service standard benchmarks during AA3 to provide an indication of the minimum level of service that should be expected by this small group of transmission-connected customers. We concluded that it is not possible to set a minimum reliability standard for transmission-connected customers that is meaningful for the individual customers. This is because the transmission network is planned with a level of redundancy[69] that is commensurate with the criticality of the transmission network – an interruption on the transmission network has the potential to impact a large number of customers. As a result there are very few interruptions on the transmission network compared to the distribution network and therefore very few interruptions experienced by transmission-connected customers.

As there are few interruptions experienced on the transmission network, the average number of interruptions experienced by transmission-connected customers will be very low but the actual number of interruptions experienced by any individual transmission-connected customers will vary significantly. While most transmission-connected customers will have no interruptions in most years, there remains the small possibility that an individual

[68] At time of writing there are 52 procuring transmission entry and transmission exit services.
[69] As required by clause 2.3.7 of the Technical Rules approved by the Authority under chapter 12 of the Access Code.

transmission-connected customer will experience an interruption. The impact of this interruption will vary depending on whether the customer has their own generation source.

This means that a minimum service standard on a reliability measure for transmission-connected customers would need to reflect a much lower level of performance than most customers would experience in any one year to accommodate the volatility over a small number of customers. The minimum service standard therefore provides little information to the majority of transmission-connected customers on the performance that they are likely to receive in any one year, as the performance they receive typically will be significantly better than the minimum service standard.

The new individual customer service measure is designed to recognise that each of the transmission customers may have very different actual experiences and that some may consider qualities other than reliability as important. Regardless of the criteria, the most important thing many of these customers require is responsiveness and accurate information. It was therefore considered that having an individual communication and service management plan will be more valuable than trying to identify a service indicator that may have very little direct relevance and meaning to any particular customer.

We will not retain the following service standard benchmarks for AA3:

- loss of supply event frequency (greater than 0.1 system minutes and greater than 1 system minute)
- system minutes interrupted (radial and meshed network)
- average outage duration

These are measures of the performance of the transmission network rather than the reference service received by transmission-connected customers. The definition of service standard benchmarks relating to network performance (rather than reference services) is not consistent with the requirement of section 5.1 of the Access Code to specify a service standard benchmark for each reference service.

We will continue to report publicly on these transmission network performance measures during AA3. This will enable interested stakeholders to compare the performance of our transmission network with other transmission utilities. Additionally, as already noted, the impact of the performance of the transmission network on the reliability of supply to distribution-connected customers will be included in the SAIDI and SAIFI measures.

When discussing the new customer service measure with transmission-connected customers, they noted that our requirement to comply with the Technical Rules will ensure that network performance levels will continue to be met.

5.5.1.3 Performance measure for transmission and distribution reference services

We will retain the circuit availability performance measure from AA2 for AA3.

This ensures we will continue to recognise the importance of the security of the transmission network for customers that receive transmission and distribution reference services.

5.5.1.4 Performance measures for street lighting reference services

We will retain two of the three AA2 performance measures for street lighting reference services for the AA3 period:

- street lighting repair times[70] – metropolitan areas

[70] The average time to repair street lights in the specified area

- street lighting repair times – regional areas

The 'street lighting repair times – major regional towns' performance measure, which was a separate service standard benchmark in AA2, will be incorporated in the 'street lighting repair times – metropolitan areas' performance measure. This more closely reflects the *Code of Conduct for the Supply of Electricity to Small Use Customers 2008*[71], which only requires reporting in two categories – metropolitan and regional areas.

5.5.2 Setting targets for the service standard benchmarks

We have set the targets for the AA3 service standard benchmarks as minimum service standards.

During the AA2 period, the performance targets for the service standard benchmarks were not set based on a minimum service standard. They were set at more ambitious levels designed to encourage service improvement. While this meant there was a strong incentive to raise performance, the service standard benchmarks were set at a level higher than can be reasonably expected to represent the minimum standard of service we are required to deliver under our licence obligations.

During AA2 we have not met all the service standard benchmarks and have therefore been at risk of non-compliance with our licence.[72] In addition, as we only get rewards under the gain sharing mechanism for cost efficiency improvements if *all* service standard benchmarks are met in a year, we have not received rewards under the gain sharing mechanism.

Setting the service standard benchmark at a level consistent with a minimum level of service will improve the probability that the benchmark will be met. Doing this will increase our certainty of achieving our obligations to provide *all* services at the service standard benchmark, which will increase the incentive to achieve cost efficiencies as the additional benefits available under the gain sharing mechanism will be less likely to be foregone.

Importantly, lowering the service standard benchmark **does not** mean that service levels will deteriorate. A further revision to the service standard framework is that there will be a strong financial incentive to deliver an **expected level** of service. This *expected level* of service is higher than the minimum standard and is comparable with the level that customers have experienced over the last five years. The financial incentive to achieve this *expected level* of performance will be provided via the service standards adjustment mechanism (SSAM).

Consistent with section 6.29 of the Access Code, the SSAM details how performance against the service standard benchmarks is to be treated at the next access arrangement review. Under the SSAM the *expected level* of performance against the service standard benchmark will be set at a level that we would *expect* to achieve 50% of the time. [73] This makes the *expected level* much more challenging to achieve than the minimum service standard, which will be set at a level we will achieve 97.5% of the time.

The result is that we would be penalised if service levels fall below what we would normally expect to achieve 50% of the time, therefore service levels should not decline despite the lower minimum standard.

This revision, in addition to the legal obligations to meet the minimum service standards, will ensure we are provided with a strong incentive to maintain and improve service compared to

[71] Clause 13.9
[72] 17 out of 19 service standard benchmarks were achieved during each of 2009/10 and 2010/11
[73] The expected performance is determined by the 50 percentile of the historical data for the last 5 years. All use being equal, actual performance is expected to be greater than the expected performance level 50% of the time and below this level 50% of the time.

current expected performance levels. The financial incentive scheme (SSAM) is discussed in further detail in section 5.6 of this document.

Figure 33 illustrates the distinction between actual service, minimum service and expected service. Actual service varies over time, while the minimum service level and expected service level will remain constant to provide certainty of the service to be received from the reference tariffs paid. It is appropriate that minimum service levels and expected service levels differ as the likelihood of achieving the service level differs.

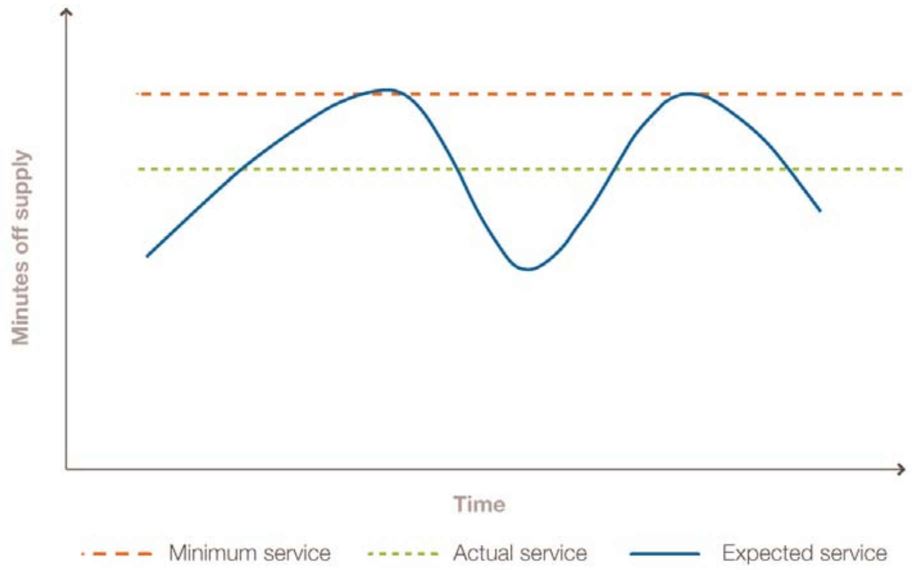

Figure 33: Example of the distinction between minimum service and expected service

If the service standard benchmarks are not set at a minimum service level, additional expenditure would be required to improve the certainty that the service standard benchmarks can be met.

We have set the service standard benchmarks for AA3 in accordance with:

- meeting that level of service 97.5% of the time based on the historical data for the past five years[74] – this is appropriate as the basis for a minimum service standard
- whether any adjustment should be made based on a greater likelihood of achieving better service due to the forecast expenditure
- comparison with the current (AA2) service standard benchmarks

The SSBs will be the same in each year of the period. This is because no investment in performance improvements has been included in the AA3 expenditure forecasts and so the likelihood of achieving the service levels will remain the same throughout the period. This is discussed further in section 5.6 of this document.

Table 12 shows the service standard benchmarks for AA3 for each performance measure and how it compares to the service standard benchmark for 2011/12.

[74] A period of five years ensures that the effects of year-on-year volatility in performance is minimised and is consistent with the period used by the AER in determining targets for the Service Target Performance Incentive Scheme.

Table 12: AA3 service standard benchmarks

Performance measure		Units	Service standard benchmark (minimum standard) for AA3	Service standard benchmark for 2011/12
Distribution reference service measures				
SAIDI	CBD	Minutes	56	38
	Urban	Minutes	200	153
	Rural short	Minutes	360	244
	Rural long	Minutes	720	556
SAIFI	CBD	Number	0.40	0.24
	Urban	Number	2.30	1.83
	Rural short	Number	4.20	2.98
	Rural long	Number	5.70	4.80
Call centre performance		Per cent	75.0	n/a
Distribution and transmission reference service measure				
Circuit availability		Per cent	97.3	98.0
Transmission reference service measure				
Individual customer service measure		Per cent	100	n/a
Street lighting reference service measures				
Street lighting repair time	Metropolitan areas	Days	5	5
	Regional areas	Days	9	9

We have set the service standard benchmarks for SAIDI, SAIFI and call centre performance based on the 97.5 percentile of the historical data for the past five years.

Charts showing the historical performance over the past five years for SAIDI, SAIFI and Call centre performance are included in section 5.7 of this document.

The service standard benchmarks for SAIDI and SAIFI will need to be updated if the operation of auto reclose devices on the distribution network is changed in response to a review currently being undertaken in Victoria. A change to the operation of auto-reclose devices on high fire risk days will reduce the risk of powerlines starting bushfires but will have a significant adverse impact on customers' reliability of supply, particularly for those customers supplied by long rural feeders.

We have set the minimum service standard benchmark for circuit availability based on the 97.5 percentile of the historical data for the past five years, adjusted to take into account the impact of an increased capital investment program for AA3 compared to the previous five years. The increased capital investment will require a greater number of planned outages, which will take circuits out of service. The service standard benchmark will be reduced by 0.5 minutes compared to the historical data to account for the additional circuits that will not be available due to the increased work program. This adjustment has been calculated by comparing the likely impact of each capital works program on circuit availability in the AA3 period to the impact of each capital works program on historical circuit availability performance data.

Charts showing the historical performance over the last five years, the adjustment for the increase in the capital works program and the service standard benchmark derived from this data for circuit availability, are included in section 5.7 of this document.

The individual customer service performance measure for transmission-connected customers is essentially a 'binary' measure – each customer *must have* an account manager, customer service management plan and the opportunity to participate in a satisfaction survey. If any of these elements are not achieved then the service standard benchmark is not met. This provides a very strong incentive to ensure that a high quality level of customer service is provided to each transmission-connected customer.

We have set the service standard benchmarks for the streetlight repair time at the same level as the service standard benchmarks for AA2, which are consistent with the repair times set out in the *Code of Conduct for the Supply of Electricity to Small-use Customers 2008.*

5.6 Financial service incentive scheme for AA3

As discussed in the previous section, we have included a service standards adjustment mechanism (SSAM) that delivers a financial reward or penalty based on our performance against the service standard benchmarks.

We have considered each of the service standard benchmarks and developed a mechanism for determining a financial reward or penalty. All but three of the service standard benchmarks will be included in the financial incentive scheme. The three service standard benchmarks that are excluded are:

1. street lighting repair time (metropolitan areas)
2. street lighting repair time (regional areas)
3. transmission individual customer service measure

For each of these benchmarks we do not consider that there is sufficient information to support a financial penalty or reward.

The following service standard benchmarks will attract a reward or penalty under the financial incentive scheme:

1. SAIDI – CBD
2. SAIDI – Urban
3. SAIDI - Rural short
4. SAIDI - Rural long
5. SAIFI – CBD
6. SAIFI – Urban
7. SAIFI - Rural short
8. SAIFI - Rural long
9. Call centre performance
10. Circuit availability

The financial reward (and penalty) has been set to reflect the likely value to customers of achieving the expected level of performance compared to the minimum level of performance. Where we achieve the *expected level* of performance, the value of the scheme is expected to be zero. We have also adjusted the formula that calculates the financial impact of the SSAM for the AA4 period to ensure that the incentive to achieve performance is consistent throughout the period.

These elements of the SSAM are discussed in the following sections.

5.6.1 Financial penalties and rewards under the SSAM

As already explained, the service standard benchmarks for AA3 have been set to reflect a high probability that the minimum service standard will be delivered. However, customers are currently receiving a higher level of service than the proposed minimum standard and we expect to be able to continue to provide a similar level of service during the AA3 period.

Therefore, in applying financial rewards and penalties to performance against the service standard benchmarks, it would be inappropriate for Western Power to receive a financial reward for delivering service that is better than the minimum standard but less than the expected performance based on the average level of service delivered over the previous five years.

Therefore, for AA3 the SSAM details a financial penalty if we deliver service that is better than the service standard benchmark but worse than the *expected level* of performance (which we expect to provide at least 50% of the time). A reward is only provided where performance against the service standard benchmark is better than the expected level of performance.

If the performance is worse than the service standard benchmark, no additional financial penalty will apply under SSAM than applies when the performance is at a minimum standard. This is because a significant disincentive already exists in the form of the potential to be non-compliant with our licence and the fact that we forego any additional rewards under the gain sharing mechanism for achieving cost efficiencies.

Any financial rewards or penalties for performance that is better or worse than the *expected level* would then be calculated in our target revenue in AA4 consistent with section 6.29 of the Access Code.

During AA2 the service standard benchmark was used as the target in the SSAM. Financial rewards (or penalties) were awarded in the first financial year under SSAM if we met (or did not meet) the service standard benchmarks. Financial rewards or penalties in subsequent years were based on the incremental change in performance relative to the improving service standard benchmarks.

The service standard benchmark was set somewhere between the minimum service standard and the *expected level* of service. Where we met the *expected level* of service, and thus exceeded the service standard benchmarks, we received financial rewards under the SSAM. Where we exceeded the minimum level of service, but did not meet the service standard benchmark, we were penalised under the SSAM, potentially at risk of non-compliance with our licence and any additional rewards for cost efficiencies under the gain sharing mechanism were foregone. This outcome is not consistent with the business being able to meets its obligations and reduces the effectiveness of the cost efficiency incentives under the gain sharing mechanism.

If we were to continue these arrangements into AA3 where the service standard benchmark triggers both the gain sharing mechanism and a financial reward, the following scenarios would arise:

1. if the service standard benchmark was set at the *expected level* (and not a minimum service standard), we would require significant additional revenue to ensure that we could undertake the investment required to deliver that benchmark each year and not put compliance with our licence at risk. To not do so would also result in the gain sharing mechanism being ineffective during the period
2. if the service standard benchmark was set at a minimum level of service, we would be more likely to remain compliant with our licence and customers and we would

benefit from the stronger cost efficiency incentives under the GSM. However, the expected value of the scheme would not be zero and would in fact result in significant rewards to Western Power for doing no more than planned

Neither of these outcomes is consistent with the Access Code objective.

The SSAM for AA3 details a financial reward or penalty based on our achieved service performance against the service standard benchmarks, as required by section 6.29 of Access Code. It also promotes the economically efficient investment in and operation of the network by ensuring investment only occurs where it is likely to deliver further improvements and then only where it costs less than the likely value to customers of that improvement.

As discussed in section 5.5.2, the *expected level* of performance will be the performance we will expect to achieve 50% of the time when compared to the average actual performance over the last five years if we undertake the actions and investment planned. The average over a five-year period has been used rather than using a single year's performance (2011/12 for example) to take into account the year-on-year volatility in performance that occurs. If a shorter period of time was used, additional expenditure would be required to ensure that the performance level is expected to be met 50% of the time.

The expected performance in relation to circuit availability will be affected by the planned investment program as the increased capital investment for the AA3 period compared to the AA2 period will require additional planned outages during the construction period which will take circuits out of service. The expected performance will be reduced by 0.3 minutes to account for the additional circuits that will not be available due to the increased works program.

The expected level of performance for each service standard benchmark detailed under the SSAM will remain the same throughout the AA3 period. This is because no investment in performance improvements has been included in the AA3 expenditure forecasts.

If the level at which the financial reward is provided was to increase over the period, then higher levels of expenditure would be required to avoid penalties. This would increase the revenue requirement and network tariffs, regardless of whether the investment was undertaken or the expected performance was actually achieved. Under this scheme no additional investment for service improvement is included in the target revenue.

The financial rewards and penalties under the SSAM will provide an incentive to maintain or improve performance where the cost of doing so is less than the rewards available under the SSAM. The incentive rate has been based on a proxy for the value to customers for service improvements (or deterioration), using an approach adopted in many other jurisdictions for this purpose.[75]

Therefore, improvements will only occur where they provide more value to customers than they cost. The financial rewards or penalties will be paid in AA4 when the outcome is delivered.

Table 13 shows the SSAM targets for AA3 based in the *expected level* of performance. It also provides a comparison with the relevant service standard benchmark for AA3 and the SSAM target in AA2.

[75] Refer to section 5.6.2 of this document for a description of the proxy used for the value of service to customers.

Table 13: SSAM targets for AA3

Performance measure		Units	Service standard benchmark (minimum standard) for AA3	SSAM target for AA3	SSAM target in AA2 (2011/12)[76]
Distribution reference service measures					
SAIDI	CBD	Minutes	56	**28**	38
	Urban	Minutes	200	**163**	153
	Rural short	Minutes	360	**254**	244
	Rural long	Minutes	720	**616**	556
SAIFI	CBD	Number	0.40	**0.22**	0.24
	Urban	Number	2.30	**1.90**	1.83
	Rural short	Number	4.20	**2.91**	2.98
	Rural long	Number	5.70	**4.77**	4.80
Call centre performance		Per cent	75.0	**88.0**	n/a
Distribution and transmission and reference service measure					
Circuit availability		Per cent	97.3	**97.7**	98.0
Transmission reference service measure					
Individual customer service measure		Per cent	100	n/a	n/a
Street lighting reference service measures					
Street lighting repair time	Metropolitan areas	Days	5	n/a	5
	Regional areas	Days	9	n/a	9

Table 13 illustrates that the financial incentive targets, which are based on expected performance, are set at a better level of performance than the service standard benchmarks, which are minimum service standards.

Table 14 shows that a similar approach applies to the distribution network businesses in an Australian jurisdiction (Queensland) that is regulated by the AER under the National Electricity Rules.

Table 14: Queensland electricity distributors – minimum service standards and service incentive targets for 2010/11

Performance measure		Units	Energex (Queensland)		Ergon (Queensland)	
			Minimum service standard	Service incentive target	Minimum service standard	Service incentive target
SAIDI	CBD	Minutes	15	3.3	N/A	N/A
	Urban	Minutes	106	69.4	149	129

[76] Note that during AA2 the SSAM targets increased in each year. This column shows the SSAM target in the final year of the period 2011/12.

Performance measure		Units	Energex (Queensland)		Ergon (Queensland)	
			Minimum service standard	Service incentive target	Minimum service standard	Service incentive target
	Rural short	Minutes	218	173.2	424	296
	Rural long	Minutes	N/A	N/A	964	699
SAIFI	CBD	Number	0.15	0.032	N/A	N/A
	Urban	Number	1.26	1.044	1.98	1.69
	Rural short	Number	2.46	2.285	3.95	3.06
	Rural long	Number	N/A	N/A	7.04	5.59

Source: Electricity Industry Code, Schedule 1; AER, Queensland distribution determination 2010/11 to 2014/15, May 2010, Tables 12.3 and 12.4

5.6.2 SSAM financial incentive rates

We have adjusted the SSAM financial incentive rates to be used to set the financial reward or penalty to better reflect the value to customers of performance improvements.

The SSAM financial incentive rate is used to determine the adjustment to target revenue that will be applied in AA4 resulting from the performance in AA3 under the SSAM. The incentive rate specifies the revenue increment or decrement on a per unit basis.

For AA3 the SSAM financial incentive rates for the distribution reference services performance measures are based on a proxy for the value that customers place on performance improvements. By doing so, we will have an incentive to improve performance only where it is economically efficient to do so – where the cost is less than or equal to the value that customers place on those performance improvements.

This is consistent with the Access Code objective and with the Authority's view expressed in its Final Decision on the Access Arrangement revisions for AA2 that the financial incentive rate for the SSAM should reflect the *value to energy customers of service disruptions*[77].

The financial incentive rate for circuit availability is set based on putting a proportion of transmission revenue at risk, consistent with the approach adopted in AA2.

As discussed previously, there are no financial incentive rates for the street lighting repair time and transmission individual customer service measures as these measures are not included in the SSAM.

[77] p297, section 1115, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, ERA, December 2009.

Table 15 sets out the SSAM incentive rates for AA3.

Table 15: SSAM financial incentive rates for AA3

Performance measure		Units	Incentive rate for AA3 ($ per unit real at 30 June 2012)	Incentive rate for AA2 ($ per unit real at 30 June 2012)
Distribution reference service measures				
SAIDI	CBD	Minutes	68,346	240,758
	Urban	Minutes	488,756	240,758
	Rural short	Minutes	199,256	8,974
	Rural long	Minutes	62,535	8,974
SAIFI	CBD	Number	7,691,084	11,271,870
	Urban	Number	43,177,909	11,271,870
	Rural short	Number	18,879,174	492,460
	Rural long	Number	8,779,766	492,460
Call centre performance		0.1 per cent	-60,190[78]	n/a
Distribution and transmission and distribution reference service measure				
Circuit availability		0.1 per cent	-712,798	-410,384
Transmission reference service measure				
Individual customer service measure		Per cent	n/a	n/a
Street lighting reference service measures				
Street lighting repair time	Metropolitan areas	Days	n/a	n/a
	Regional areas	Days	n/a	n/a

SAIDI and SAIFI

We have calculated the financial incentive rates for the SAIDI and SAIFI performance measures using the best information available on the value that customers place on improvements in reliability. We have used the value of customer reliability (VCR) as determined by Charles River Associates (CRA) for VENCorp[79] in 2007[80], and on a willingness to pay study undertaken by KPMG for the Essential Services Commission of South Australia in 2002[81]. The AER adopts a similar approach.[82]

CRA determined the VCR for four customer segments – residential, commercial, industrial and agricultural. The aggregate Victorian VCR is calculated by weighting these customer segment VCRs by the energy consumed by each customer segment in Victoria. We have used the VCR by customer segment and reweighted these using the energy consumed by

[78] Note that the incentive rate is positive where improving performance is reflected by reducing the number of units (eg fewer minutes off supply or fewer interruptions = better performance), and negative where improving performance is reflected by an increasing number (eg higher % of calls answered within 30 seconds = better performance).
[79] Now the Australian Energy Market Operator
[80] Available at http://www.aemo.com.au/planning/0409-0002.pdf
[81] Available at http://www.escosa.sa.gov.au/library/030916-PublicConsumerSurvey-KPMG.pdf
[82] Section 3.2.2(f)(2), *Electricity distribution network service providers, Service target performance incentive scheme*, AER, November 2009.

each customer segment for each feeder type in the Western Power Network. The VCR has then been escalated to June 2012 dollars.

By using this approach, the aggregate VCR for the Western Power Network is $62,256 per MWh compared to the Victorian aggregate VCR of $55,420 per MWh (in June 2012 dollars). The aggregate VCR for the Western Power Network is higher than the aggregate Victorian VCR because the proportion of energy consumed by commercial and agricultural customers connected to the Western Power Network is higher than in Victoria. The VCRs for these types of customers have been determined by CRA to be higher than the VCRs for residential and industrial customers.

Each interruption has an impact on SAIDI and SAIFI. We have allocated the VCR between SAIDI and SAIFI based on the same weightings used by the AER[83], which were derived from the 2002 South Australian willingness to pay study. Table 16 shows the weightings by feeder type.

Table 16: Weightings for SAIDI and SAIFI

Feeder type	Ratio of SAIDI to SAIFI
CBD	1.13
Urban	0.97
Rural short	0.92
Rural long	0.92

The AA3 incentive rates are greater than the AA2 incentive rates for SAIDI and SAIFI on urban, rural short and rural long feeders and are similar or less than for SAIDI and SAIFI on CBD feeders.

We have conducted customer research to determine customers' preferences for different levels of reliability performance compared against other services.[84] The customer research was not designed to determine the value that customers place on reliability. This is why we have relied on the VENCorp study.

Our customer research indicates that, on average, customers were satisfied with the current level of reliability. However, there are areas of the network where an improvement in reliability is preferred when the cost to improve reliability was not taken into consideration, particularly by customers on long rural feeders. The increase in the incentive rates for rural feeders will provide a greater incentive to improve reliability performance on rural feeders where it is economically efficient to do so.

Call centre performance

We have calculated the incentive rate for call centre performance using the best information available on the value that customers place on improvements in call centre performance. We have used the same incentive rate that is used by the AER in its Service Target Performance Incentive Scheme, which is based on a 2002 South Australian willingness to pay study.[85]

The incentive rate for the call centre performance measure is 0.04% of distribution revenue for each percentage point change in the call centre performance measure.

[83] Section 3.2.2(f)(2), *Electricity distribution network service providers, Service target performance incentive scheme*, AER, November 2009.
[84] KPMG customer preferences for supply reliability report March 2011 based on survey conducted in October 2010.
[85] Section 5.3.2(a)(1), *Electricity distribution network service providers, Service target performance incentive scheme*, AER, November 2009.

Circuit availability

We have calculated the incentive rate for the circuit availability performance measure by placing 0.5% of transmission revenue at risk through this measure. This is the same approach that was used in AA2 and the percentage is similar to the percentages used for circuit availability by other Australian electricity transmission companies.

The AA3 incentive rate for circuit availability is higher than the AA2 incentive rate. This is because the AA3 transmission revenue is higher than the AA2 transmission revenue and the proportion of transmission revenue at risk for this performance measure is higher in AA3 than in AA2.

Street lights and transmission individual customer service measure

The two streetlight repair time performance measures will attract neither penalty nor reward as there is not sufficient information available to determine a value to customers of increasing or decreasing the time in which street lights are repaired.

The financial penalty or reward for the individual customer service measure for transmission-connected customers will also attract neither penalty nor reward as we have no historical information to support a different value. The experience during the AA3 period will contribute to the treatment and value these indicators may attract in future periods.

5.6.3 SSAM revenue impact formula

We have changed the formula that calculates the impact of SSAM on AA4 target revenue to ensure there is a consistent incentive for performance improvements in each year during AA3.

In accordance with section 6.29 of the Access Code, the SSAM that applies during AA3 will impact the revenue in AA4.

The SSAM revenue impact formula that is used to calculate the adjustment to target revenue for AA3, based on performance during AA2, calculates the reward or penalty based on the incremental improvement in performance relative to the targets. It applies the reward or penalty in one year only.

This distorts the incentives across the access arrangement period. It provides an incentive for performance improvements to be undertaken towards the end of the access arrangement period. The reward or penalty is the same regardless of which year the performance improvement is undertaken, but the costs incurred during the access arrangement period will be higher the earlier the improvement is undertaken. This distortion would be amplified if the same SSAM revenue impact formula was applied to a five year access arrangement period compared to a three year period.

The AA3 SSAM revenue impact formula will determine the difference between the actual performance and the performance target. This formula rewards improvements relative to the target rather than the current AA2 approach which rewards incremental improvements only during the period. The incentive to improve performance will be the same in each year during AA3 – the earlier the performance improvement is undertaken, the higher the costs incurred during the access arrangement period and the higher the rewards under the SSAM.

If the SSAM targets are set for subsequent access arrangements in the same way that they have been set for AA3 (that is, based on the average of the last five years’ performance), the rewards and penalties for any improvement or deterioration in performance will always effectively apply for a five-year period – regardless of the year in which the improvement or deterioration occurs. This ensures that there is no distortion in the incentives within an access arrangement period and between access arrangement periods.

The SSAM revenue impact formula is the same formula as that used by the AER in the Service Target Performance Incentive Scheme.[86] The formula is:

$$\mathbf{SSD_t = (SST - SSA_t)}$$

where:

SSD_t is the service standard difference in year t

SST is the SSAM target, as set out in Table 13

SSA_t is the actual service performance in year t

The revenue adjustment in AA4 is the sum of SSD_t with the incentive rate, as set out in Table 15, applied to the SSDt for each performance measure.

When adjusting the AA4 target revenue based on performance against the SSAM during AA3, the adjustment shall take into account the time value of money and inflation over the AA3 period.

5.6.3.1 Allocating SSAM adjustment to transmission and distribution revenue

We will allocate the SSAM adjustment to target revenue between transmission revenue and distribution revenue.

The distribution revenue, which covers the cost of the distribution network, is recovered from distribution-connected customers receiving a distribution reference service. The transmission revenue, which covers the cost of the transmission network, is recovered from both transmission-connected customers receiving a transmission reference service and distribution-connected customers receiving a distribution reference service, as discussed in section 5.2.1.

The distribution reference service performance measures of SAIDI and SAIFI reflect the performance experienced by distribution-connected customers associated with both the transmission network and the distribution network.

To ensure that the financial incentive scheme (SSAM) promotes economically efficient investment in the distribution and transmission networks, we will monitor the transmission and distribution components of SAIDI and SAIFI. An adjustment will be made to the transmission revenue based on the performance of the transmission network and an adjustment will be made to the distribution revenue based on the performance of the distribution network, subject to any applicable caps (which are discussed in section 5.6.3.3).

The SSAM revenue adjustment arising from the circuit availability performance measure will be allocated to the transmission revenue as it relates to performance of the transmission network only. The SSAM revenue adjustment from the call centre performance measure will be allocated to the distribution revenue as the call centre is predominantly used by distribution-connected customers.

The way in which the SSAM adjustment to target revenue will be allocated to distribution revenue and to transmission revenue is shown in Figure 34.

[86] *p32-33, Electricity distribution network service providers, Service target performance incentive scheme*, AER, November 2009; and
p50-51,Electricity distribution network service providers, Service target performance incentive scheme, AER, March 2011.

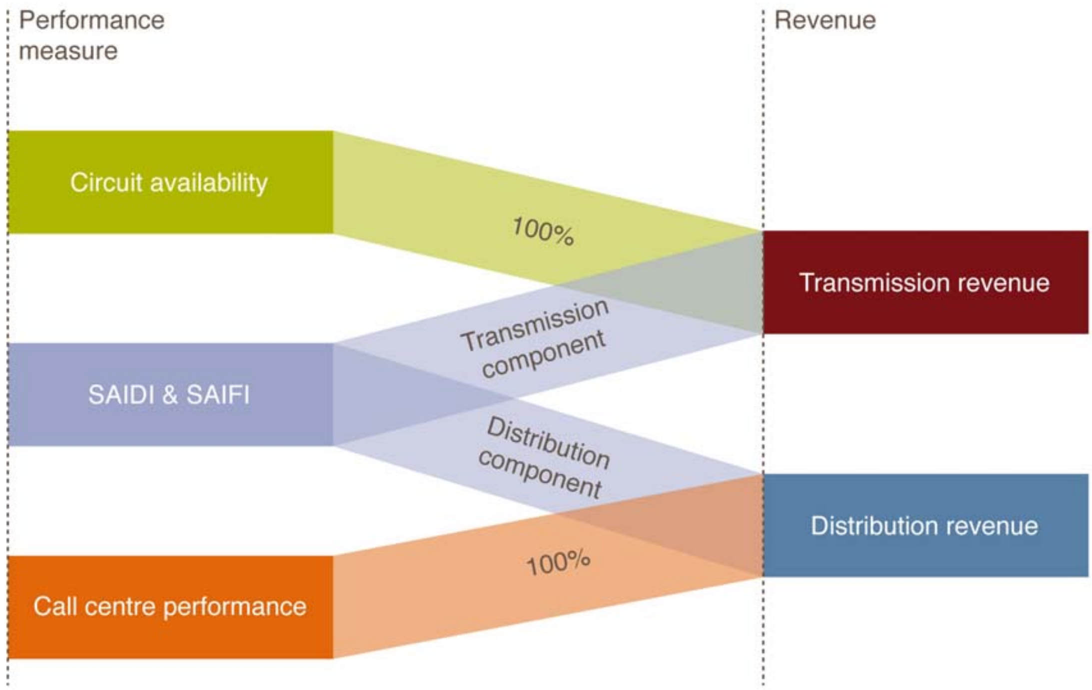

Figure 34: Allocation of SSAM service standard benchmark performance to distribution and transmission revenue

5.6.3.2 Transitional adjustment to revenue

We will make a one-off transitional adjustment to the target revenue in AA4 to offset a potential windfall gain or loss arising from the change in the SSAM revenue impact formula from AA2 to AA3.

If the AA2 SSAM revenue impact formula was continued into AA3, the reward or penalty with respect to 2012/13 performance would be based on the incremental performance improvement from 2011/12 to 2012/13. With the change in the SSAM revenue impact formula for AA3, the reward or penalty with respect to 2012/13 performance will be based on the performance in 2012/13 relative to the SSAM target, which may be higher or lower than the performance in 2011/12.

A transitional adjustment will be made which provides a reward or penalty for the difference between the actual performance in 2011/12 and the target for SSAM in the AA3 period. This will ensure that customers effectively pay for the same level of performance as the SSAM targets at the commencement of the AA3 period, rather than for the 2011/12 performance.

For example, if the performance is better in 2011/12 than the new SSAM target for AA3, we will receive a revenue decrement through the transitional adjustment. If performance is then maintained in 2012/13 at the same level of performance as 2011/12, the revenue decrement will offset the revenue increment that we would otherwise be paid through the SSAM for the performance in AA3.

The transitional adjustment will be applied only to the performance measures that are included in the SSAM in AA3 and were included in the SSAM in AA2. That is, the transitional adjustment will be applied only to circuit availability and to SAIDI and SAIFI with interruptions on the transmission network excluded.

The service standard targets to be used in the transitional adjustment will be the SSAM targets for AA3, adjusted to align with the definitions of the service standard benchmarks that were used during AA2 (that is, the transitional service standard targets for SAIDI and SAIFI will exclude interruptions on the transmission network) and to exclude the adjustment to circuit availability for the increase in the capital works program.

The transitional adjustment will be based on the incentive rates in the AA2 period, using the following formula:

$$\mathbf{SSAdj_{2012/13} = (SSA_{2011/12} - TSST)}$$

where:

$SSAdj_{2012/13}$ is the service standard adjustment to transition from the AA2 period to the AA3 period

TSST is the transitional service standard target

$SSA_{2011/12}$ is the actual service performance in the final year of the AA2 period

with the incentive rate for the AA2 period applied to the $SSAdj_{2012/13}$ for each performance measure that is included in the SSAM in both AA2 and AA3

The adjustment, based on the transition to the new SSAM, will be applied when the adjustment for the performance in AA3 is made to the target revenue in the AA4 period. This transitional adjustment ensures that the SSAM adjustment that is made to the target revenue in AA4 better reflects the actual performance achieved in AA3, consistent with section 6.29 of the Access Code, rather than a revenue adjustment that arises solely from the change in the design of the SSAM from AA2 to AA3.

5.6.3.3 Capping the risk of SSAM to Western Power and its customers

We will cap the total rewards or penalties payable under the SSAM during the AA3 period at 5% of distribution revenue and 1% of transmission revenue to limit the downside risk of the SSAM for Western Power and our customers.

The revenue at risk through a financial incentive scheme such as SSAM is generally capped to limit the increase in tariffs paid by customers, if rewards are being paid to the service provider and to limit the decrease in revenue received by the service provider, if penalties are being paid by the service provider, so as not to threaten its financial viability.

Caps are set by balancing the financial impact of the scheme with the impact on the incentive power of the scheme.

The cap on transmission revenue is generally set lower than the cap on distribution revenue. This is because the performance of the transmission network is generally very high and so there is more downside risk than upside risk with the SSAM. Additionally, the performance of the transmission network can be more volatile – there is a small number of large events on the transmission network compared to a large number of small events on the distribution network. The 1% cap on the transmission revenue at risk is consistent with the cap that applies during AA2.

There is currently no cap on the distribution revenue at risk. It is prudent to introduce a cap during AA3 given the significant increase in some of the financial incentive rates that will apply under SSAM during AA3. However, if the cap on the distribution revenue that is at risk is set too low, the performance improvements in the distribution reference service that could be delivered through SSAM will be constrained by the cap. On balance, we consider that a 5% revenue cap provides the best option for capping the downside risk and providing opportunities for performance improvements.

The caps on the revenue at risk that we will apply during AA3 are consistent with the caps placed on the rewards and penalties under the Australian Energy Regulator's Service Target

Performance Incentive Schemes for electricity distribution network businesses[87] and electricity transmission businesses.[88]

The Access Code currently links the service standard benchmarks to the SSAM and the efficiency incentive (gain sharing mechanism). Currently there is a double penalty when the service standard benchmarks are not met – the penalty under the SSAM continues to increase and any additional reward for efficiency improvements under the gain sharing mechanism is foregone.

To remove the potential for double penalties, we will cap the penalty for each performance measure at the service standard benchmark. By doing so, all three mechanisms will operate as follows:

- if the actual performance is better than the SSAM target (that is, better than the expected level of performance) and thus also better than the service standard benchmark (that is, better than the minimum service standard), we will be compliant with our legal obligations, rewarded under the SSAM and will also be entitled to additional rewards under the gain sharing mechanism for efficiency improvements
- if the actual performance is worse than the SSAM target (that is, worse than the expected level of performance) but better than the service standard benchmark (that is, better than the minimum service standard), we will be compliant with our legal obligations and penalised under the SSAM but will be entitled to rewards under the gain sharing mechanism for efficiency improvements
- if the actual performance is worse than the service standard benchmark (that is, worse than the minimum service standard), we will potentially be non-compliant with our legal obligations, will receive the maximum penalty under the SSAM for that performance measure[89] and any rewards under the gain sharing mechanism for efficiency improvements will be foregone

Figure 35 illustrates the relationship between each of the mechanisms (legal obligation to meet the service standard benchmarks, SSAM and gain sharing mechanism).

[87] Section 2.5.1(a), *Electricity distribution network service providers, Service target performance incentive scheme*, AER, November 2009.
[88] Section 3.4, *Electricity distribution network service providers, Service target performance incentive scheme*, AER, March 2011.
[89] The capped penalty will be determined by setting the actual performance as the service standard benchmark in the SSAM revenue impact formula.

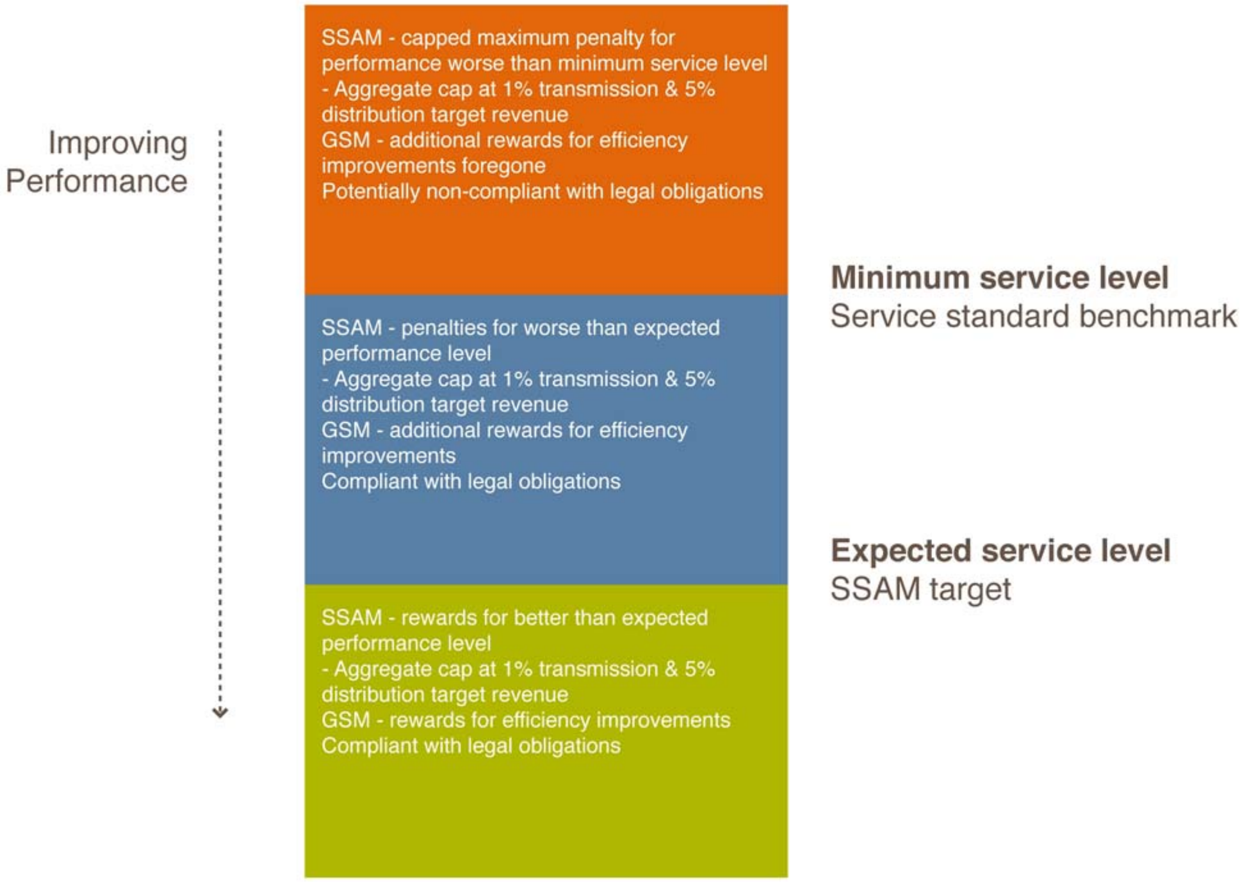

Figure 35: Relationship between the legal obligation to meet service standard benchmarks, SSAM and gain sharing mechanism

The rewards for each performance measure will effectively be capped by the total revenue at risk. There will not be an individual cap on the rewards for each performance measure. For example, the incentive rate for SAIDI and SAIFI for rural feeders has significantly increased from AA2 to AA3, which will provide a stronger incentive to improve the reliability for customers supplied by rural feeders, where it is economically efficient to do so. If there was a cap on the rewards for each performance measure, the incentive to improve the reliability of rural feeders would be weakened.

5.6.4 Exclusions

As in AA2, we will continue to exclude events that are outside of our control when measuring our performance for the purposes of the service standard benchmarks and the SSAM in AA3.

In summary:

- We will exclude the same events from the measurement of SAIDI and SAIFI during AA3 as we did during AA2, other than interruptions on the transmission network. As discussed in section 5.5.1.1, we will include transmission interruptions in the SAIDI and SAIFI measure during AA3 as we are responsible for both the distribution and transmission networks.

- We will exclude the following events from our new call centre performance measure:
  - the impact of any major event day excluded from SAIDI and SAIFI
  - the impact of any third party affecting the ability to create and receive calls to the extent that Western Power could not provide for the continuity of service

  Excluding these two events from our call centre performance measures ensures we are not adversely impacted by events that are outside our control.
- We will exclude force majeure events from the street lighting performance measures for AA3.
- We will exclude the same events from circuit availability during AA3 as we did during AA2. However, we will change the wording so it is consistent with the Access Code.

5.7 Performance targets for service standard benchmarks and SSAM

The way we set the performance targets for the service standard benchmarks and SSAM is described in sections 5.5.2 and 5.6.1 respectively.

The service standard benchmarks and SSAM targets have been set by considering five years of data to determine an *expected level* of performance. This is because external factors such as weather conditions and customer activity can affect actual performance levels. Therefore a five-year data set is more appropriate than basing the measures on a single point in time, as it will account for the effects of year-on-year volatility. If a different period was used, additional expenditure would be required to ensure that the SSAM target continued to be the *expected level* of performance and the service standard benchmarks would be met 97.5% of the time.

A period of five years is consistent with the period used by the Australian Energy Regulator in determining targets for the Service Target Performance Incentive Scheme.

The historical performance, AA3 service standard benchmark and AA3 SSAM targets are illustrated for:

- SAIDI (by feeder type) in Figure 36 to Figure 39
- SAIFI (by feeder type), in Figure 40 to Figure 43
- Call centre performance, in Figure 44
- Circuit availability, in Figure 45

Figure 36: SAIDI, CBD – historical performance, AA3 service standard benchmark and AA3 SSAM target

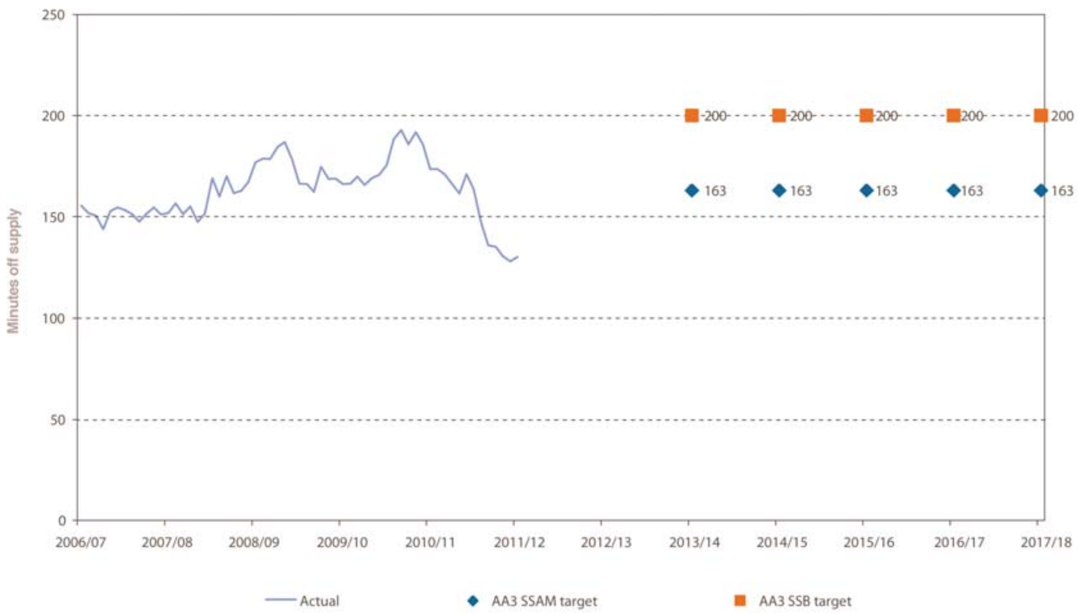

Figure 37: SAIDI, urban – historical performance, AA3 service standard benchmark and AA3 SSAM target

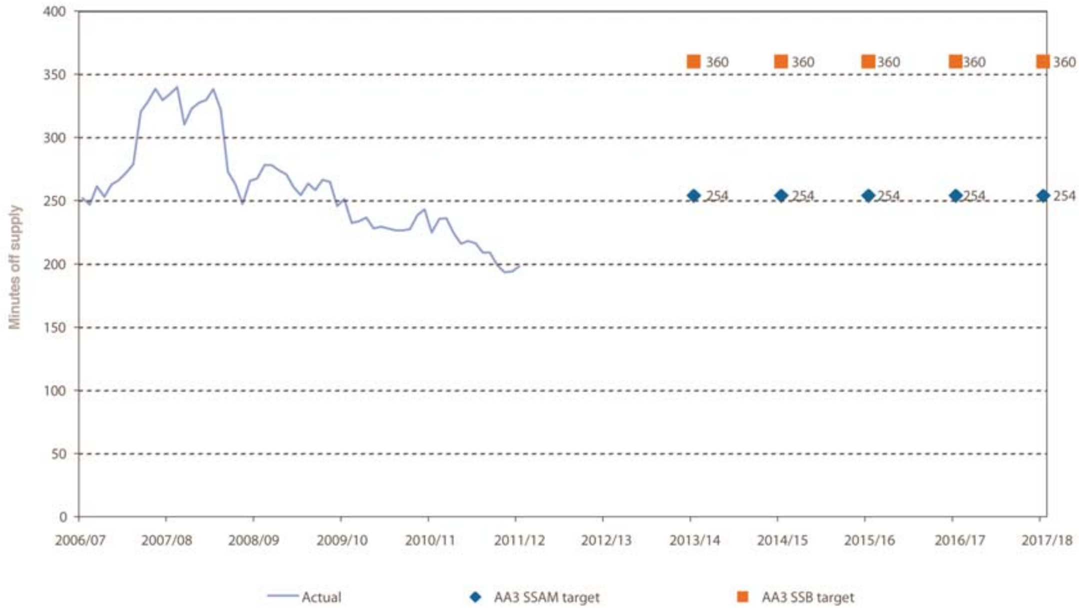

Figure 38: SAIDI, rural short – historical performance, AA3 service standard benchmark and AA3 SSAM target

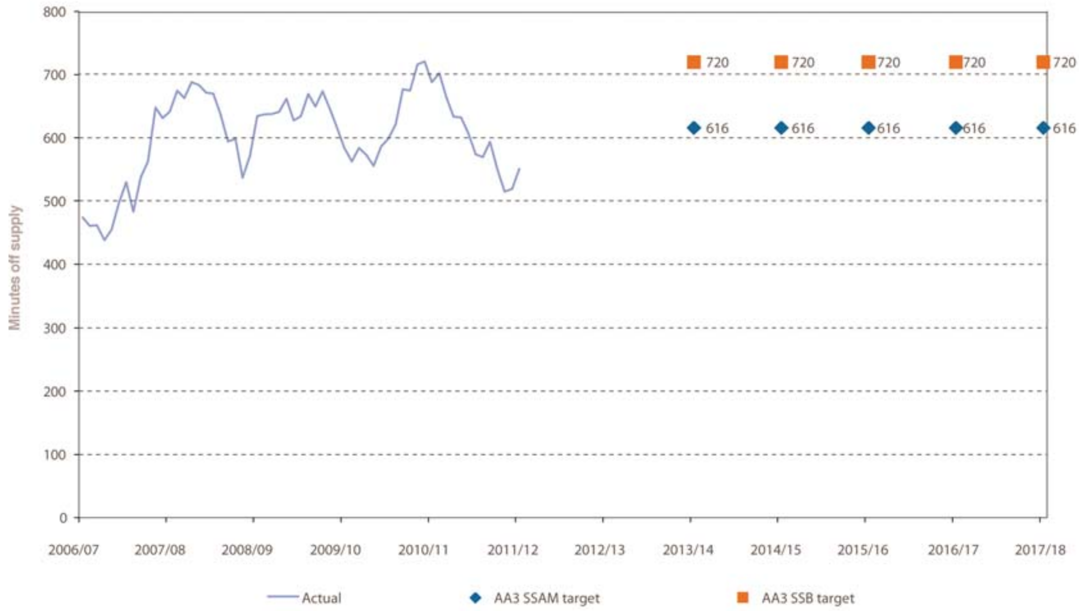

Figure 39: SAIDI, rural long – historical performance, AA3 service standard benchmark and AA3 SSAM target

Figure 40: SAIFI, CBD – historical performance, AA3 service standard benchmark and AA3 SSAM target

Figure 41: SAIFI, urban – historical performance, AA3 service standard benchmark and AA3 SSAM target

Figure 42: SAIFI, rural short – historical performance, AA3 service standard benchmark and AA3 SSAM target

Figure 43: SAIFI, rural long – historical performance, AA3 service standard benchmark and AA3 SSAM target

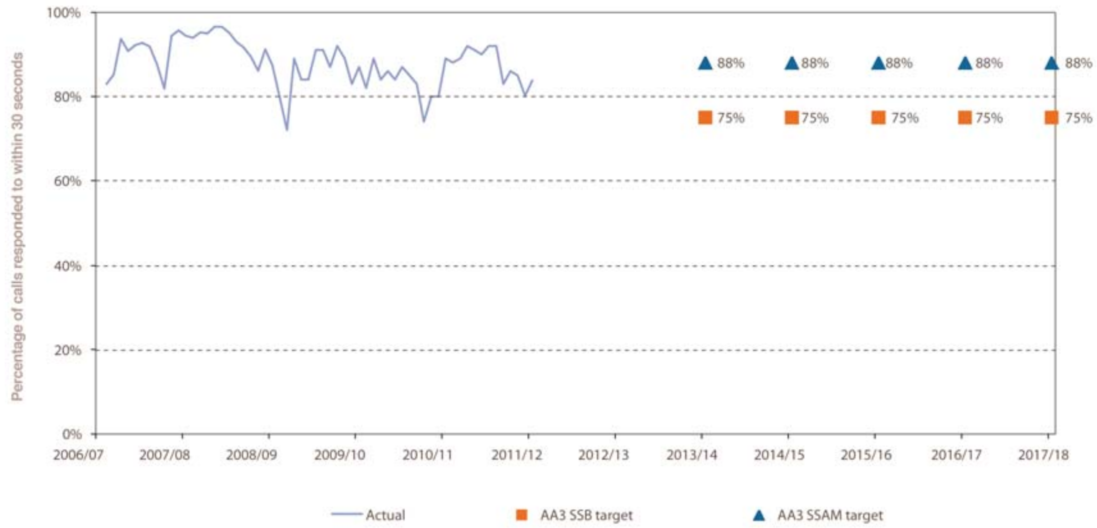

Figure 44: Call centre performance – historical performance, AA3 service standard benchmark and AA3 SSAM target

Figure 45: Circuit availability – historical performance, AA3 service standard benchmark and AA3 SSAM target adjusted for the works program

5.8 AAI Guidelines provisions

The information that is required to be included in the access arrangement information in relation to the service standard benchmarks is detailed in section 6 of the AAI Guidelines.

Table 17 details the requirements with a cross reference to the relevant section of this AAI.

Table 17: AAI Guidelines compliance for the service standard benchmarks

AAI Guidelines section #	AAI Guidelines wording	Cross reference
6.1	*Access arrangement information should include information to support the service provider's proposal for particular service standard benchmarks and actual service standard performance.*	Chapter 5
6.3	*Access arrangement information must include information to support a service provider's claim that a service standard benchmark for a reference service is reasonable and sufficiently detailed and complete to determine the value of the reference service.*	Section 5.5.1
6.3	*As a minimum, supporting information should include a detailed explanation as to how the service standard benchmarks were set, including:* • *details and justification of any historical measures/trends that were used as the basis to determine the service standard benchmarks for the forthcoming access arrangement period; and* • *details and justification of any adjustments made to correct for factors that are likely to cause service standards to vary from historical measures/trends (for example, new investment or changes to maintenance activities that directly or indirectly affect service quality).*	Section 5.5 and 5.7
6.4	*Service standard performance reports prepared by the service provider, in response to requests made by the Authority under section 11.3 of the Access Code, may be referenced and/or included as part of the access arrangement information. Regardless of this, access arrangement information must include as a minimum:* • *a description of and explanation for the service standard benchmarks that apply to each reference service in the access arrangement, including the method for calculation; and* • *for each year of the access arrangement period, the actual service standard performance achieved for each reference service, in comparison with the service standard benchmark that was set for the reference service; and* – *where actual performance is equivalent to, or better than, the service standard benchmark, information in support of any actions or plans that were undertaken (and/or to be undertaken) to achieve (and/or to maintain) the performance level; or* – *where actual performance is worse than the service standard benchmark, detailed reasons as to why this is the case and information in support of any actions or plans to be undertaken to improve the performance level.*	Section 3.2

6 Growth and demand

This chapter outlines Western Power's peak demand, energy consumption and customer number forecasts for the AA3 regulatory period.

This chapter explains:

- the methodology for developing the forecasts
- key forecasting inputs
- how the forecasts were verified
- how the forecasts affect the AA3 investment proposal

Access Code provisions

Section 4.3

Access arrangement information must include:

a) *information detailing and supporting the price control in the access arrangement*

b) *information detailing and supporting the pricing methods in the access arrangement*

c) *if applicable, information detailing and supporting the measurement of the components of approved total costs in the access arrangement*

d) *information detailing and supporting the service provider's system capacity and volume assumptions.*

This chapter satisfies part d) of this requirement.

6.1 Key messages

- We forecast that over the AA3 period, the average annual growth will be:
  - 3.2% in peak demand
  - 2.4% in the number of customers
  - 2.8% in energy consumed by distribution-connected customers
- We have a robust externally assured forecasting methodology that is consistent with good electricity industry practice.
- The growth in peak demand and the number of customers drives the need for investment in our network to ensure there is sufficient capacity available in the network to connect new customers and to service growing peak demand.
- The prices that will be paid by our customers are impacted by the forecast number of customers and energy consumption; higher forecasts will lead to lower prices and conversely lower forecasts will lead to higher prices.
- If our growth forecasts are too high or too low, and a different investment program to that proposed results, the investment adjustment mechanism provides that customers will only pay for the investment program that actually occurs.
- If our growth forecasts are too high or too low, and more or less revenue is earned, the revenue cap provides that customers will not be charged more than they should.
- Our forecasts are revised annually as part of the annual planning cycle. Our investment proposal is based on the **November 2010** forecast. We do not anticipate that the November 2011 forecast will result in a material impact on our investment proposal.

6.2 Peak demand forecast for AA3

We forecast peak demand to increase by an average of 146 MW per year (3.2%) during AA3. This is similar in to the average annual increase from 1998/99 to 2009/10, which was approximately 147 MW.[90]

The peak demand is the maximum rate of energy consumption during any half hour period in a year. We must plan to meet this peak demand, even if this level of demand is only reached for a very short time. If the network does not have sufficient capacity (including reserve capacity) to meet peak demand, it impacts our ability to connect new customers and to maintain the security, reliability and quality of supply. Figure 46 illustrates that the capacity to meet peak demand, while essential, is only actually required for a short period of time.

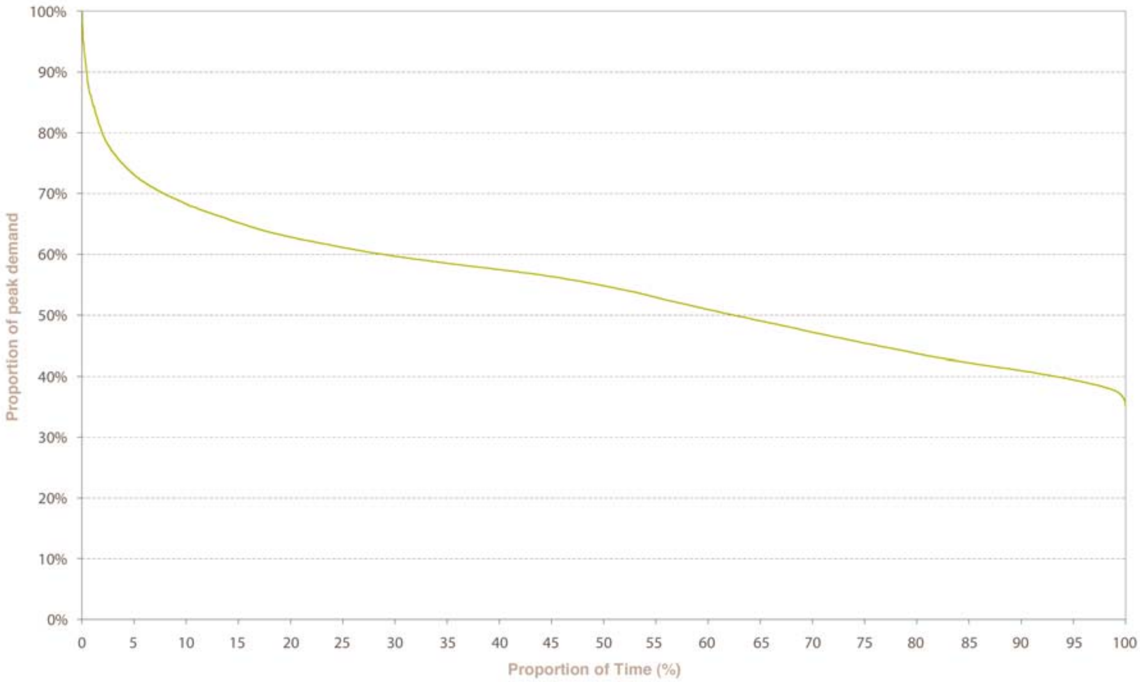

Figure 46: Load duration curve[91]

Peak demand in the Western Power Network occurs in summer. It is caused predominantly by air conditioning on hot summer days. The growth in peak demand is higher than the growth in energy consumption due to the increasing penetration of air conditioning.

The actual peak demand in any year is largely dependent on a variety of factors such as customer behaviour, temperatures experienced over summer and economic activity. Peak demand typically occurs on a working weekday following consecutive days where the temperature reaches above 40 degrees Celsius.

As these factors vary from year to year, we forecast peak demand based on two scenarios:

[90] The average peak demand increase from 1998/99 to 2009/10 is actually more in percentage terms as the increase across AA3 is from a larger base.

[91] This load duration curve shows the proportion of time that the demand is above a certain level, for example, the demand is more than 60% of peak demand approximately 30% of the time.

1. **a probability of exceedance of 50% (PoE50)** – the peak demand that is expected to be reached one in every two years
2. **a probability of exceedance of 10% (PoE10)** – the peak demand that is expected to be reached one in every ten years

Consistent with our peers, we plan investment in our transmission network based on the PoE10 and in our distribution network based on the PoE50. The different approaches are driven by the different levels of criticality of the networks. If we do not have sufficient capacity in any part of the transmission network, there is the potential for the electricity supply to a large number of customers to be interrupted. Insufficient capacity in the distribution network would impact a much smaller number of customers.

Peak demand is also forecast based on a central growth scenario and a high growth scenario. The difference between the central growth scenario and the high growth scenario is driven by different assumptions on the timing of new block loads. The central growth scenario is based on all confirmed block loads connecting to the network as expected and is therefore the most likely case. The high forecast assumes that the confirmed block loads will connect earlier than expected and also includes block loads that are not yet confirmed but could potentially connect during the period.

Table 18 shows the major block loads included in the forecast central and high growth scenarios for AA3.

Table 18: Major block loads included in the central growth and high growth peak demand forecasts[92]

Potential new major block loads (over 20 MW)	Central growth scenario		High growth scenario	
	First year load included in forecast	Load (MW)	First year load included in forecast	Load (MW)
Southern Seawater Desalination Plant Stage 1 & 2 & 3	2011	16	2011	31
	2012	15	2016	31
	2018	31	-	-
Simcoa 3rd & 4th furnace expansion project	2012	24.3	2012	24.3
	-	-	2016	24.3
Asia Iron Ltd. - Extension Hill Mine Site	-	-	2014	112.5
Gindalbie stage 1.1	2012	86	2012	86
Gindalbie stage 1.2	2013	23	2013	23
Gindalbie stage 2.1	-	-	2014	27
Gindalbie stage 2.2	-	-	2015	45
Gindalbie stage 2.3	-	-	2017	45
Gindalbie stage 2.4	-	-	2018	45
Port of Oakajee stage 1	2014	27	2014	27
Port of Oakajee stage 2	-	-	2018	15
Oakajee industrial estate heavy (smelter)	-	-	2017	28

[92] Some of the loads will commence after the AA3 period but any investment that may be required in the network to supply those loads will occur during the AA3 period.

Potential new major block loads (over 20 MW)	Central growth scenario		High growth scenario	
	First year load included in forecast	Load (MW)	First year load included in forecast	Load (MW)
	-	-	2018	30
Grange Resources mine	-	-	2015	160
Port and pumping facilities for Grange Resources	-	-	2015	20

Our forecast investment in the network is based on the central growth scenario. However, we also consider the high growth scenario in planning the network. This is because we need to be aware of the potential impact on the network if all potential block loads occur. This ensures that our plans to meet the central growth scenario have the flexibility to cater for network changes should the high growth scenario materialise. This is particularly important when developing plans for transmission ‘backbone’ assets, as this infrastructure is extremely costly to alter.

Figure 47 and Table 19 show the PoE10 and PoE50 peak demand forecasts using the central growth scenario for the AA3 period. Peak demand is forecast to increase by 3.2% per year, or 146 MW per year, during AA3. An additional two or three zone substations are required each year to meet this growth in peak demand.

The year-on-year variability in the actual peak demand is driven by the variability in summer temperatures, economic activity and consumption activity of customers. The actual peak demand in 2010/11 was lower than the actual peak demand in 2009/10 and lower that the forecast PoE50 peak demand for that year, which was 3,874 MW. This was because the actual peak demand was lower in 2010/11 as we did not experience extreme summer temperatures on consecutive working weekdays.

The increase in the forecast peak demand from 2010/11 to 2011/12 is much higher than in other years due to the addition of several major block loads (refer to Table 18 for a list of forecast major block loads).

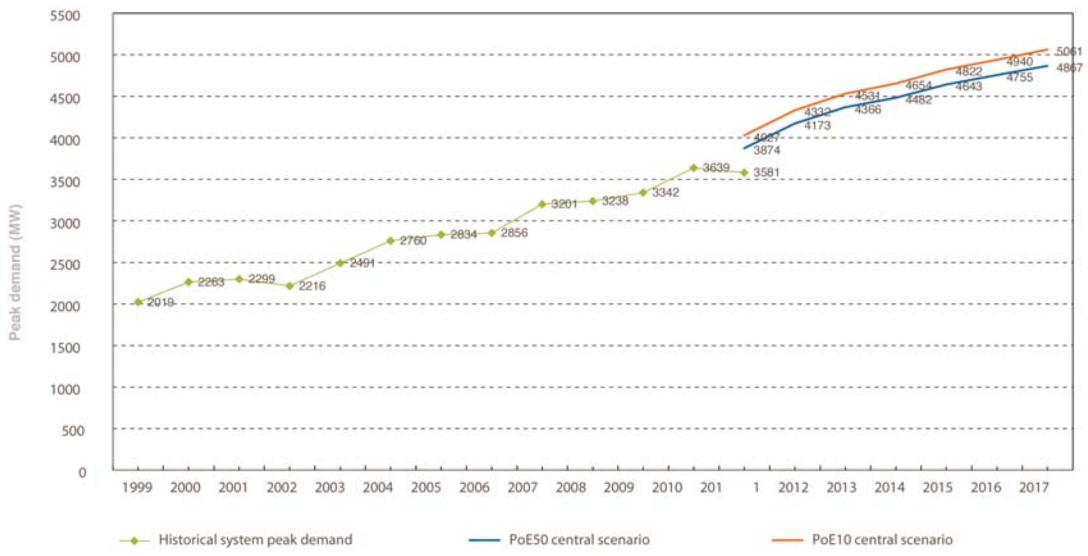

Figure 47: Peak demand forecasts – central growth scenario

Table 19: Peak demand forecast – central growth scenario

	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Actual peak demand (MW)	3639	3581						
Demand forecast (MW) (PoE50)		3874	4173	4366	4482	4643	4755	4867
Demand forecast (MW) (PoE10)		4027	4332	4531	4654	4822	4940	5061
Annual change (MW)			305	199	123	168	118	121
Annual growth (%)			7.6%	4.6%	2.7%	3.6%	2.4%	2.4%

Figure 48 illustrates the difference between the PoE10 peak demand forecasts based on the central and high growth scenarios.

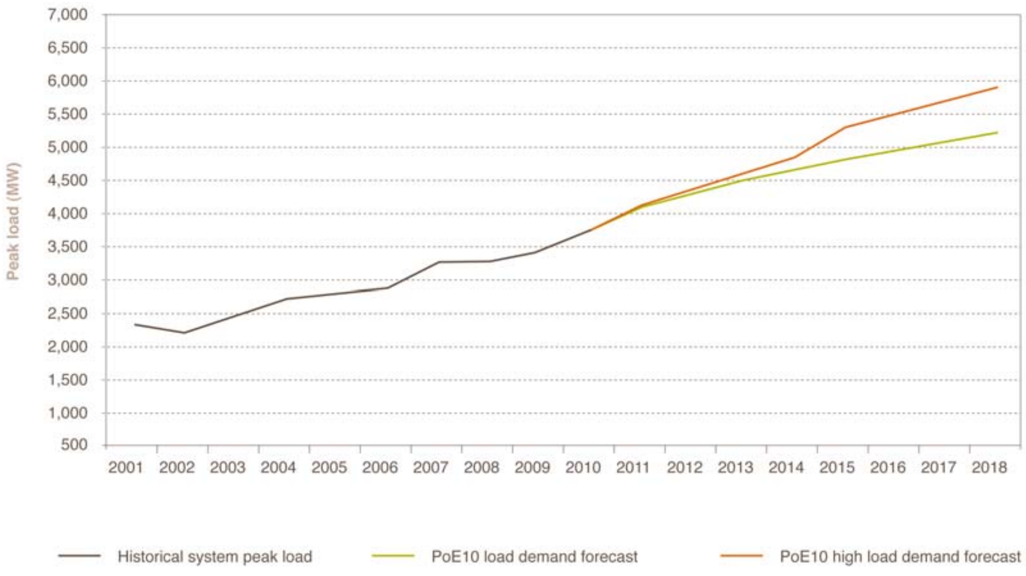

Figure 48: Comparison of forecast peak demand based on the central and high growth scenario

We forecast the peak demand using a bottom-up approach as it is the growth in the peak demand at each zone substation that is the driver of investment in the network. For each zone substation, we:

- use regression analysis on the historical data to forecast the base peak demand
- adjust the base forecast to take into account:
    - o any reconfiguration of the network that will impact the peak demand at that zone substation
    - o connection or disconnection of block loads
    - o annual variations in the historical data due to, for example, temperature and the price of electricity
    - o the impact of any policy changes, where applicable

To forecast the peak demand across the network, the peak demands for each zone substation are aggregated. As the peak demand for a zone substation may not occur at the same time as the peak demand across the network, each zone substation's peak is determined to understand their individual peak growth.

The growth in peak demand across the network provides an indication of the growth in the peak demand at each zone substation but is not the driver for investment in the network. Further details on our method are set out in Appendix P: System demand forecasting for AA3.

The growth in peak demand, and therefore the required investment in the network, is forecast to vary significantly across substations and across regions.

As illustrated in Figure 49, peak demand is projected to increase between 0% to 5% in the country east region, 10% to 15% in the metro east and country south regions, and 15% to 20% in the metro north, metro CBD, metro south, country north and goldfields regions over the AA3 period. No areas are expected to have a reduction in peak demand over the AA3 period.

LEGEND

- 15-20 % decrease
- 10-15 % decrease
- 5-10 % decrease
- 0-5 % decrease
- 0-5 % increase
- 5-10 % increase
- 10-15 % increase
- 15-20 % increase

REGION	FORECAST 2012 PEAK DEMAND (MW)	FORECAST 2017 PEAK DEMAND (MW)
Metro CBD	394	441
Metro North	1186	1409
Metro South	1461	1763
Metro East	208	230
Country North	268	312
Country South	484	553
Country East	226	231
Country Goldfields	105	122
TOTAL	4332	5061

Figure 49: Growth in peak demand (10 POE, central growth scenario) by region from 2012 to 2017

Our peak demand forecasts have been verified internally against the peak demand forecasts published by the Independent Market Operator (IMO) in the annual Statement of Opportunities. They have also been independently reviewed by forecasting experts, SKM MMA.

In verifying our peak demand forecasts against the IMO's peak demand forecasts, we need to consider the differences between the two forecasts. These differences arise because the forecasts are used for different purposes and therefore forecast the peak demand at a different point in the system. The IMO forecasts the peak demand that is required to be supplied by generators – it includes losses on the transmission and distribution network. Our forecast of peak demand does not include losses in the transmission network.

Additionally we adopt a more conservative approach than the IMO to forecasting new block loads. This is because the IMO's role is to ensure there is sufficient generation to supply new block loads and therefore includes **all** potential new block loads in its forecast. As we receive advance notice of new block loads through connection applications, we do not need to include more speculative new block loads in our forecasts.

Following its external review of our forecasting method, input assumptions and results, SKM MMA concluded that:

> *… the forecasting methodology adopted by Western Power is comparable with good industry practice throughout Australia.*[93]

Further details on SKM MMA's external review are provided in Appendix S: SKM/MMA report – Review of WP's demand forecasts for the AA3 period.

It should also be noted that our forecasts are revised annually as part of the annual planning cycle and are typically produced in November. As a result, the forecasts incorporated in this submission are based on the **November 2010** forecast.

The IMO has recently published its 2011 peak demand forecast. The IMO's new forecast is lower than the forecast it published in 2010.

When we revise our forecasts in November 2011 we anticipate that they may also be reduced. However, we do not believe that this will result in a material impact on our investment proposal because:

- our capital investment requirements are driven by growth at the zone substation level. If a reduction in peak demand at the system level is not accompanied by a reduction in peak demand at those zone substations that require additional capacity, there will be no change in investment
- investment to increase capacity is necessarily lumpy. This means that often an increase in load will result in a larger increase in capacity as the minimum size of new facilities may be greater than the new load
- we expect some reductions in peak demand at the system level due to the installation of photovoltaic (PV) systems. However, this will only reduce investment requirements if the PV systems are concentrated at locations with existing network constraints
- one result of lower demand forecasts may be to improve our compliance with the Technical Rules in areas where investment is not avoided but the spare capacity available has increased

[93] p1 *Review of Western Power's Demand Forecasts for the AA3 Period (2011/12 to 2016/17),* SKM MMA, November 2010.

- we expect less variation in block loads as our forecasts do not include loads that are uncertain

Investment in the transmission network is dependent on generation as well as the peak demand in load. Further detail on the generation scenarios is provided in Appendix Q: ROAM report.

6.3 Customer number forecasts for AA3

We have forecast that the number of customers will increase by 2.4% per year in the AA3 period. This is consistent with the growth in customer numbers in the 2005/06 – 2010/11 period, during which the number of customers grew by 2.5% per year.

The forecast number of customers:

- drives the forecast increase in energy consumption, as discussed in section 6.4
- drives investment in new customer connections and meters for those new customers
- is an input into the determination of distribution tariffs. For a given revenue, the higher the growth in customer numbers, the lower the distribution tariffs

Table 20 shows the forecast number of customers for AA3, by customer group.

Table 20: Forecast number of customers, by customer group

Customer numbers	2009/10 (Actual)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Residential	875,153	897,157	918,707	940,318	962,228	984,377	1,006,546	1,028,496
Small Business (<15 kVA)	83,643	88,084	91,807	94,994	98,007	101,138	104,475	107,906
General Business Small (15-100 kVA)	16,227	17,089	17,811	18,429	19,014	19,621	20,269	20,934
General Business Medium (100-300 kVA)	2,475	2,606	2,717	2,811	2,900	2,993	3,091	3,193
General Business Large (300-1000 kVA)	906	954	994	1,029	1,062	1,096	1,132	1,169
High Voltage < 1MVA	90	95	99	102	105	109	112	116
Customers > 1MVA (high and low voltage)	436	445	455	459	461	464	467	470
Total customer numbers	**978,930**	**1,006,430**	**1,032,589**	**1,058,143**	**1,083,776**	**1,109,797**	**1,136,093**	**1,162,284**
Total customer numbers (growth p.a.)		27,500	26,159	25,554	25,633	26,021	26,296	26,191
Total customer numbers (% growth p.a.)		2.8%	2.6%	2.5%	2.4%	2.4%	2.4%	2.3%

We engaged Deloitte to forecast the number of customers, by customer group, for the AA3 period.

The forecast was prepared based on:

- the number of customers in 2009/10, as the starting point
- the historical trends in customer numbers over the five year period 2005/06 to 2009/10

- economic and demographic factors – different factors were used to forecast residential customers and general business customers

The economic and demographic data used to forecast the number of residential customers was the projected growth in household numbers provided by the Australian Bureau of Statistics[94]. Deloitte found that:

> *…growth in residential customer connections and growth in household numbers is reasonably closely correlated, albeit that the number of residential sites connected (as recorded by Western Power) is growing slightly faster than household numbers*[95.]

The projected growth rate for the number of households in the Perth area and outside the Perth area is set out in Table 21. These growth rates were applied to the number of customers in the Perth area and outside the Perth area in 2009/10, respectively, to forecast the number of residential customers in the AA3 period.

Table 21: Assumed growth rate from Australian Bureau of Statistics (released 6 June 2010)

Growth rates in number of households	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Perth household number growth	2.54%	2.44%	2.39%	2.38%	2.36%	2.31%	2.25%
Non-Perth household number growth	2.39%	2.23%	2.17%	2.11%	2.06%	1.99%	1.89%

The economic and demographic data used to forecast the number of general business customers was the forecast gross state product (GSP) for Western Australia.

> *… Deloitte believes that (discounted) GSP growth is likely to offer the best indicator of business growth. Using the available data, over the five years to the 2009/10 FY, the number of businesses with connections between 15kVA and 1000kVA has grown at an annual average rate of 4.05%, with GSP growth over the same period of 4.26%. Acknowledging the small sample of observations, it is plausible that the rate of growth in business customer numbers (including small business (<15kVA)) will be somewhere between 90% and 100% of the rate of growth in GSP – 90% pass through and 100% pass through will be reflected in the expected and high case scenarios respectively*.[96]

The growth in the number of general business customers was assumed to be 90% of the forecast gross state product (GSP) for WA, consistent with a central growth scenario, as set out in Table 22. This growth rate was applied to the number of general business customers in 2009/10 to forecast the number of general business customers in the AA3 period.

Table 22: AA3 forecast growth in the number of general business customers

Economic assumption	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Forecast growth in GSP for WA	5.90%	4.70%	3.86%	3.52%	3.55%	3.67%	3.65%
Assumed business customer growth as a % of GSP growth	90%	90%	90%	90%	90%	90%	90%

[94] *ABS Cat No. 3236.0 Household and Family Projections, Australia 2006 to 2031, tables 1.15 and 1.16 (released 6 June 2010), Series II.*

[95] p12, *Western Power – Energy and customer number forecasts for the AA3 period (2012/13 to 2016/17),* Deloitte, 11 August 2011.

[96] p16, *Western Power – Energy and customer number forecasts for the AA3 period (2012/13 to 2016/17),* Deloitte, 11 August 2011.

Economic assumption	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Forecast growth in the number of general business customers	5.31%	4.23%	3.47%	3.17%	3.19%	3.30%	3.28%

Further details on the forecasting method are provided in Appendix T: Deloitte report – Energy and customer numbers forecast for the AA3 period.

6.4 Energy consumption forecasts for AA3

We have forecast that the energy consumed by our distribution-connected customers will increase on average by 2.8% per year in the AA3 period. The historical and forecast annual growth rates vary by customer segment as shown in Table 23.

Table 23: Historical and forecast annual growth in energy consumed by distribution-connected customers, by customer segment

Growth rates in energy consumption	Historical annual growth rate (2006/07 – 2009/10)	Forecast annual growth rate (2010/11 – 2016/17)
Business > 1 MVA	-3.0%	1.2%
Business < 1 MVA	3.2%	2.9%
Residential and small business < 15 kVA	3.1%	3.7%

Table 23 indicates that the forecast annual growth in energy consumption for AA3 is highest by residential and small business customers and lowest by large business customers (with consumption greater than 1 MVA).

The forecast annual growth rate in energy consumption by large business customers is higher than the historical annual growth rate largely because the energy consumed by this customer group decreased by more than 6% from 2008/09 to 2009/10. This may have been a response to the global financial crisis.

The forecast annual growth rate in energy consumption by business customers with consumption less than 1MVA is lower than the historical annual growth rate due to a forecast decrease in the energy use per customer.

The forecast annual growth rate in energy consumption by residential and small business customers is higher than the historical annual growth rate due to a higher forecast in the energy use per residential customer. The forecast change in energy use per customer was provided by Deloitte in Appendix T.

The energy consumption forecast is a key input into the determination of distribution tariffs. For a given revenue, the higher the energy consumption forecast, the lower the distribution tariffs. Although investment in the network is driven by peak demand rather than energy consumption, energy consumption has been used as a proxy in setting distribution tariffs. The metering technology that has been historically available provides little information on the time of use or peak demand.

Figure 50 and Table 24 show the forecast energy consumed by distribution-connected customers by customer group for the AA3 period.

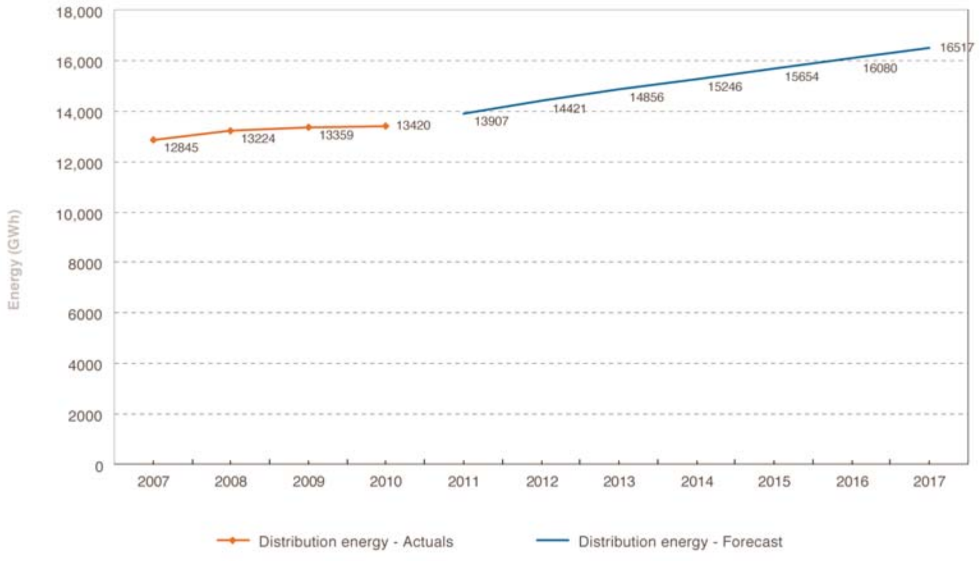

Figure 50: Forecast energy consumed by distribution-connected customers

Table 24: Forecast energy consumed by distribution-connected customers, by customer group

Energy consumption (GWh)	2009/10 (Actual)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Residential	5,498	5,720	5,946	6,177	6,416	6,663	6,915	7,172
Small Business (<15 kVA)	828	867	900	926	951	976	1,003	1,031
General Business Small (15-100 kVA)	1,499	1,571	1,629	1,677	1,722	1,768	1,817	1,867
General Business Medium (100-300 kVA)	972	1,019	1,056	1,088	1,117	1,146	1,178	1,211
General Business Large (300-1000 kVA)	1,156	1,211	1,256	1,293	1,327	1,363	1,401	1,440
High Voltage < 1MVA	163	171	178	183	188	193	198	204
Customers > 1MVA (high and low voltage)	3,304	3,347	3,457	3,512	3,525	3,545	3,567	3,592
Total distribution-connected customers	13,420	13,907	14,421	14,856	15,246	15,654	16,080	16,517
Growth (GWh p.a.)		487	514	435	390	408	426	437
Growth (% p.a.)		3.6%	3.7%	3.0%	2.6%	2.7%	2.7%	2.7%

We engaged Deloitte to forecast energy consumption for the AA3 period. The energy consumption forecast was prepared based on:

- forecast number of customers for the AA3 period, as discussed in section 6.3
- average energy use per customer in 2009/10, as a starting point
- forecast growth in the average energy use per customer for the AA3 period, which was prepared based on:
    - the historical trends in energy use per customer over the five year period 2005/06 to 2009/10

- industry research on trends in energy use per customer

The energy consumption was forecast by multiplying the forecast number of customers by the forecast average energy use per customer. The average energy use per customer was forecast by escalating the average energy use per customer in 2009/10 by the forecast growth in the average end use per customer, as set out in Table 25.

Table 25: Forecast growth in energy use per customer

Growth rates in energy use	2012/13	2013/14	2014/15	2015/16	2016/17
Energy use per customer – growth rate residential	1.50%	1.50%	1.50%	1.50%	1.50%
Energy use per customer – growth rate general business	-0.50%	-0.50%	-0.50%	-0.50%	-0.50%

Further details on the method are provided in Appendix T: Deloitte report – Energy and customer numbers forecast for the AA3 period.

We have verified Deloitte's energy consumption forecast by comparing it to our peak demand forecast. The energy consumption forecast and the peak demand forecast were compared by converting them both to the sent out energy (including distribution and transmission loads and distribution losses).

The forecast energy consumed by distribution-connection customers was converted to forecast energy sent out by:

- adding distribution and transmission losses and the load associated with streetlights and unmetered supplies, by using a historical percentage of energy consumed by distribution-connected customers
- adding energy consumed by transmission-connected customers by:
  - adding the energy consumed by existing transmission-connected customers, assuming no change in energy consumption
  - adding the energy consumed by new transmission-connected customers, assuming that the new block loads have a load factor of 70%[97]

The forecast PoE50 peak demand was converted to forecast energy sent out by applying a forecast load factor. The load factor was forecast using a linear projection of the historical load factor, as shown in Figure 51.

[97] The load factor is the proportion of energy consumed relative to the maximum energy that could be consumed if the load was operating 100% of the time.

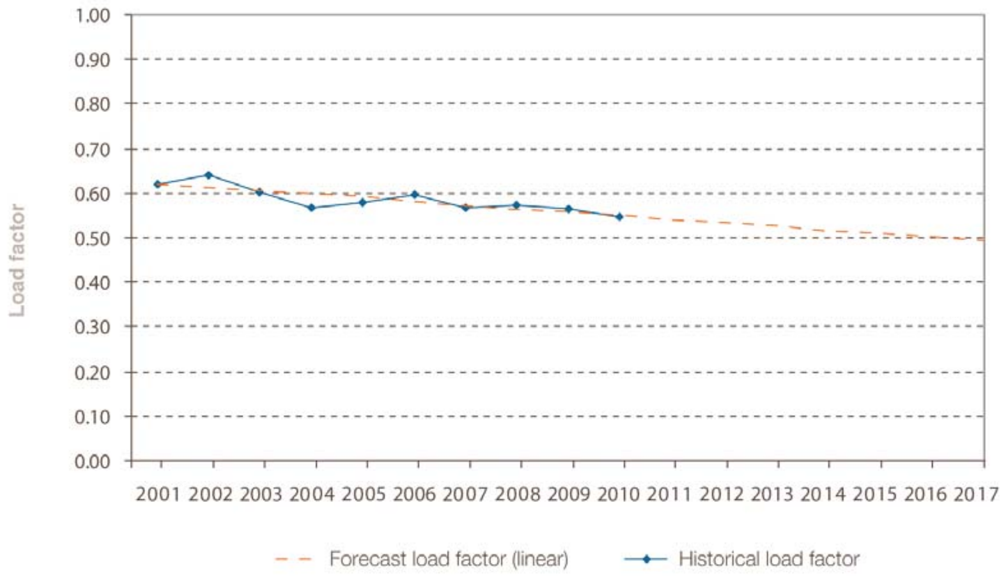

Figure 51: Historical and forecast load factor

Table 26 shows a comparison of the forecast sent out energy using these two approaches.

Table 26: Forecast sent-out energy

Energy sent-out (GWh unless otherwise specified)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Energy consumption – distribution customers	13,907	14,421	14,856	15,246	15,654	16,080	16,517
Distribution system losses / streetlights / un-metered supplies	785	815	839	861	884	908	933
Energy consumption – transmission customers	2,812	3,580	3,721	3,887	3,887	3,887	3,887
Sent out energy (excl transmission losses)	**17,505**	**18,816**	**19,417**	**19,994**	**20,425**	**20,875**	**21,337**
Peak demand forecast PoE50 (MW)	3,874	4,173	4,366	4,482	4,643	4,755	4,867
Forecast load factor (%)	54.20%	53.42%	52.63%	51.84%	51.06%	50.27%	49.48%
Sent out energy (excl transmission losses) (forecast load factor applied)	**18,395**	**19,527**	**20,129**	**20,355**	**20,767**	**20,940**	**21,098**
Variance (%)	4.8%	3.6%	3.5%	1.8%	1.6%	0.3%	-1.1%

Deloitte concluded that[98]:

> *The variance between the Deloitte expected case sent-out energy forecast and the (implied) Western Power expected case sent-out forecast is up to 4.8% in the earlier part of the outlook period but falls to around (negative) 1.1% at the end. This variance is relatively small compared to some of the other forecasts and, given that the Western Power and Deloitte forecasts have been prepared on quite different*

[98] p37, *Western Power – Energy and customer number forecasts for the AA3 period (2012/13 to 2016/17),* Deloitte, 11 August 2011.

> *bases, suggests a reasonable level of internal consistency between Western Power's expected demand forecast ("central forecast") and the Deloitte expected energy forecast.*

We agree with Deloitte's conclusion, noting that the reconciliation is very sensitive to the load factor assumption and that the actual peak demand in 2010/11 was less than forecast, reducing the variance between the two approaches in 2010/11. Further details on the verification are provided in Appendix T: Deloitte report – Energy and customer numbers forecast for the AA3 period.

7 Operating expenditure

This chapter sets out the operating expenditure Western Power requires to provide covered services during AA3 and demonstrates how these meet the relevant Access Code requirements. It:

- describes how we have forecast our AA3 operating expenditure
- details the activities and disaggregated forecasts for key transmission, distribution and corporate regulatory cost categories
- demonstrates that the forecasts are consistent with those that would be incurred by a service provider efficiently minimising cost as required by the Access Code, including through trend analysis and benchmarking

> **Efficiently minimising costs** is defined in the Access Code as:
>
> *the service provider incurring no more costs than would be incurred by a prudent service provider, acting efficiently, in accordance with good electricity industry practice, seeking to achieve the lowest sustainable cost of delivering covered services and without reducing service standards below the service standard benchmarks set for each covered service in the access arrangement or contract for services.*
>
> **Good electricity industry practice** is defined in the Access Code as:
>
> *the exercise of that degree of skill, diligence, prudence and foresight that a skilled and experienced person would reasonably and ordinarily exercise under comparable conditions and circumstances consistent with applicable written laws and statutory instruments and applicable recognised codes, standards and guidelines.*

Western Power's non-capital costs comprise operating and maintenance expenditure for both the transmission and distribution networks. It also includes non-network or corporate expenditure, which supports the operation of the business through administration activities, staff, accommodation and business support functions. These costs are hereafter collectively referred to as 'operating expenditure'.

Detailed information on activities and forecast expenditure by regulatory cost category for operating expenditure is set out in **Error! Reference source not found.**: AA3 capital and operating expenditure report.

7.1 Key messages

- During AA3 operating expenditure will total $2.714 billion, compared with $2.077 billion over the preceding five-year period (2007/8 to 2011/12). The increase is driven by:
  - growth in the size of the network and customer numbers
  - forecast movements in the market costs of labour and materials
  - non-recurring costs for network control services, the introduction of new technologies, the field survey data capture project and removal of transmission lines that are no longer in service
- Our forecast operating expenditure reflects the efficient costs of providing covered services and meets the regulatory requirements under the Access Code and the AAI Guidelines.
- Our forecasting method is consistent with the forecasting techniques adopted by other Australian regulated electricity networks and accepted by their regulators.

Access Code provisions

Western Power's operating expenditure for the AA3 period is required to comply with a number of provisions of the Access Code namely sections 6.40 to 6.42.

Section 6.40

Subject to section 6.41, the non-capital costs component of approved total costs for a covered network must include only those non-capital costs which would be incurred by a service provider efficiently minimising costs.

Section 6.41

Where, in order to maximise the net benefit after considering alternative options, a service provider pursues an alternative option in order to provide covered services, the non-capital costs component of approved total costs for a covered network may include non-capital costs incurred in relation to the alternative option ("alternative option non-capital costs") if:

a) the alternative option non-capital costs do not exceed the amount of alternative option non-capital costs that would be incurred by a service provider efficiently minimising costs; and

b) at least one of the following conditions is satisfied:

i. the additional revenue for the alternative option is expected to at least recover the alternative option non-capital costs; or

ii. the alternative option provides a net benefit in the covered network over a reasonable period of time that justifies higher reference tariffs; or

iii. the alternative option is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

Section 6.42

For the purposes of section 6.41(b)(i) "additional revenue" for an alternative option means:

a) the present value (calculated at the rate of return over a reasonable period) of the increased tariff income reasonably anticipated to arise from the increased sale of covered services on the network to one or more users (where "increased sale of covered services" means sale of covered services which would not have occurred had the alternative option not been undertaken);

minus

b) the present value (calculated at the rate of return over the same period) of the best reasonable forecast of the increase in non-capital costs (other than alternative option non-capital costs) directly attributable to the increased sale of the covered services (being the covered services referred to in the expression "increased sale of covered services" in section 6.42(a)),

where the "rate of return" is a rate of return determined by the Authority in accordance with the Code objective and in a manner consistent with this Chapter 6, which may be the rate of return most recently approved by the Authority for use in the price control for the covered network under this Chapter 6.

7.2 Forecasting methods

We have forecast operating expenditure using fit-for-purpose methods for each of the three cost types:

1. **recurrent network costs**
2. **non-recurrent network costs**
3. **corporate costs**

The forecasting methods used reflect the differing cost drivers of each cost type over the five-year forecasting period.

To forecast the **recurrent network costs** operating expenditure forecast, we have taken the efficient base year, identified the required cost adjustments (step changes related to scope) and escalated these costs by the size of the network and customer base (scale escalation).

For **non-recurrent network costs** and **corporate costs** we have developed bottom-up forecasts to take into consideration the nature of the works program and the effect of factors other than scale.

We have then applied expensed indirect network costs (those not directly attributed to individual projects) to the **recurrent** and **non-recurrent** network costs, as outlined in the cost and revenue allocation method (attached at **Error! Reference source not found.**). To complete the forecasting method, we have adjusted all three cost types for forecast movements in the price of labour and materials (input cost escalation).

These methods are described in further details in section 7.2.1 to 7.2.5 of this chapter.

Table 27 sets out each of the components used to develop the operating expenditure forecast, including the expensed indirect costs and input cost escalation that were applied to the cost types as described above.

Table 27: Build up of operating expenditure forecasts

$ million real at 30 June 2012[99]	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Recurrent network base	251.8	251.8	251.8	251.8	251.8	251.8	251.8	1,259.1
Step changes		4.0	5.0	5.0	5.0	5.0	5.0	25.0
One-off adjustments		11.5	8.7	8.7	8.7			26.1
Network growth		7.3	16.4	25.2	34.3	43.6	53.0	172.5
Customer growth		0.6	1.3	1.9	2.6	3.3	4.0	13.1
Total recurrent network costs	**251.8**	**275.2**	**283.2**	**292.6**	**302.4**	**303.7**	**313.9**	**1,495.8**
Non-recurrent network costs	**36.0**	**42.3**	**42.9**	**38.6**	**42.9**	**47.0**	**52.9**	**224.4**
Expensed indirect network costs	44.9	52.2	54.3	51.3	50.2	48.3	54.9	259.1
Corporate costs	**102.5**	**109.3**	**107.9**	**107.6**	**109.8**	**114.3**	**116.2**	**555.9**
Input cost escalation			8.1	19.7	35.2	49.1	66.3	178.4
Total AA3 operating expenditure	**435.3**	**479.0**	**496.4**	**509.9**	**540.6**	**562.5**	**604.2**	**2,713.6**

7.2.1 Recurrent network costs

We have forecast recurrent network operating expenditure using a base year roll-forward method. This method is appropriate as our operating expenditure mainly comprises recurrent costs which are typically stable over time once you account for growth in the size of the physical network or customer numbers and changes in the market price of inputs. This method is also the accepted standard used by other regulated Australian distribution and transmission network businesses for forecasting recurrent operating costs under the National Electricity Rules.[100]

[99] Less existing recurrent indirect network costs and non-recurring cost categories.
[100] See for example:

- *Final decision Victorian electricity distribution network service providers distribution determination 2011-2015, AER, October 2010.*
- *Final decision South Australia distribution determination 2010–11 to 2014–15*, AER, May 2010.
- *Final decision Queensland distribution determination 2010–11 to 2014–15*, AER, May 2010.
- *Final decision Australian Capital Territory distribution determination 2009–10 to 2013–14,* AER, 28 April 2009.

Our recurrent network operating expenditure forecast uses the last actual cost of delivering services as the starting point. This practice best ensures forecast operating expenditure includes *only those non-capital costs which would be incurred by a service provider efficiently minimising costs* as required by section 6.40 of the Access Code. This is because under the existing revenue cap and efficiency incentive regime, we have an ongoing incentive to efficiently minimise costs to meet current obligations within the AA2 period and forego profit if we do not.[101]

In forecasting recurrent network operating expenditure (for both transmission and distribution) we have:

- used actual 2010/11 costs (excluding indirect costs) as the efficient base year to develop the AA3 forecasts
- removed non-recurring 2010/11 costs that are not expected to continue into AA3
- adjusted for relevant step changes related to known future changes in practices, functions, obligations and operating environment that affect the scope for recurrent works as identified through our 2011/12 budget process and review of future requirements
- applied scale escalation to adjust for growth in physical network size and the number of customers connected to our network
- added the expensed share of indirect network costs
- applied input cost escalation to adjust for movements in the market price of labour and materials

2010/11 as the efficient base year

We have developed our recurrent network operating expenditure forecasts based on our actual 2010/11 costs. These costs are the most up to date information available on which to determine our efficient recurrent network cost base. They constitute a relevant cost base against which forecasts of operating expenditure for AA3 can be assessed consistent with the Authority's considerations in its AA2 determination.[102]

2010/11 is the most recent year of actual expenditure and reflects efficiently minimised costs because:

- operating and maintenance activities were planned and carried out in accordance with good electricity industry practice as documented in our Network Management Plan, condition monitoring processes and work instruction manual

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- *Final decision New South Wales distribution determination 2008–09 to 2012–13*, AER, 28 April 2009.
- *Final Decision Transend Transmission Determination 2009–10 to 2013–14, AER*, 28 April 2009.
- *Final decision, ElectraNet transmission determination 2008–09 to 2012–13, AER*, 11 April 2008.
- *Final decision SP AusNet transmission determination 2008–09 to 2013–14, AER*, January 2008.

[101] Under the current regulatory incentive framework Western Power can retain efficiency benefits within the period and potentially carry some over into AA3 via the gain sharing mechanism – subject to meeting the service standard benchmarks targets.

[102] p510, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, ERA, July 2009.

- we are subject to commercial incentives including the retained benefit from achieving in-period operational efficiencies under the revenue cap and the compounding benefit under the gain sharing mechanism
- the year incorporates benefits and efficiencies achieved by improvements in governance and operational excellence activities implemented over time (see section 3.8 of this document for an overview of the governance improvements made during AA2)
- commercial outsourcing and competitive tendering has ensured that unit costs of operating activities have been market tested

Further, benchmarking of our costs in 2010/11 year against our network peers (provided in section 7.9) demonstrates that we have been efficiently minimising costs such that our costs compare favourably with our network peers on most cost metrics.

Cost adjustments

We have adjusted for step changes related to known future changes in practices, functions, obligations and operating environment. These are costs that were incurred in the base year (2010/11) that will not be incurred in the AA3 period (negative step changes) and costs that will be incurred in the AA3 period that were not incurred in the base year (positive step changes). We assessed that there is a negative step change of $0.3 million per year and a positive step change of $5.3 million per year.

In addition, we will require $26.1 million over the AA3 period for a one-off increase in operating expenditure. This one-off increase only applies until 2014/15. These adjustments are necessary to ensure the base year reflects the recurrent costs relevant to the AA3 period.

Our recurrent cost base setting process involves examining our actual 2010/11 costs to identify recurrent step changes in operating activities. This is primarily through our 2011/12 budget setting process and includes activities that we expect to impact future costs as well.

We have identified specific changes that will affect operating expenditure requirements in the AA3 period (relative to 2010/11). These include:

- changes in obligations (either new or ceased)
- changes in our operating environment and practices that will affect the nature or volume of activities required to comply with an existing obligation, such as:
  - volume shifts in the quantity of a given activity
  - initiatives designed to improve cost efficiency or safety that will provide a net benefit over a reasonable period of time
  - activities that have been conducted for a discrete time period which conclude during AA3

These factors have given rise to two forms of required forecast adjustment:

- step changes to the 2010/11 base year to account for known changes in recurrent costs between 2010/11 and 2011/12 and those expected in the AA3 period
- one-off adjustment in costs for short-term variances in the volume or scale of recurrent activities

We have adjusted our actual 2010/11 base year for the following costs set out in Table 28.

Table 28: Network cost adjustments

Cost activity	Value per year ($ million real at 30 June 2012)	Year	Nature of adjustment	Description
Step changes				
Transmission SCADA and communications	$0.8 million	2011/12	+ recurrent	Operational and maintenance activities associated with the additional SCADA and communications infrastructure added to the existing network
	$1.0 million	2012/13	+ recurrent	To accommodate the new Clarity/ Oracle licences and support contract after the completion of the project in 2009/10
Distribution metering	$0.5 million	2011/12	+ recurrent	To increase the number of metering verifications and compliance testing expected from the planned changes to the Metering Code[103] due to be gazetted in December 2011
Distribution corrective emergency	$3.0 million	2011/12	+ recurrent	To ensure a sustainable level of corrective works. 2010/11 was not a typical year for corrective works, with a 20% lower than expected level of faults on the network – this is not expected to continue
Distribution Preventative routine – fuse pole clearing	$0.3 million	2011/12	- recurrent	Efficiencies gained by bundling with vegetation inspections and anticipated savings through the completion of the fire safe fuses program
Total step changes	**$5.0 million**			
One-off adjustments				
Distribution preventative condition – pole maintenance	$8.7 million	2012/13 – 2014/15	+ non-recurrent	To address the backlog of pole conditions to ensure safety and compliance outcomes
Total one-off adjustments	**$26.1 million (over the AA3 period)**			

The proposed recurrent cost adjustments reflect Western Power's best view at this point in time of the known changes during AA3. However, it is likely that changes are likely to arise during the course of the AA3 period that may require additional operating (and capital) expenditure.

[103] Changes to clause 5.3(3) of the Metering Code will introduce the requirement for Western Power to use reasonable endeavours to undertake a meter reading that provides an actual value at least once in any 12 month period. This clause will replace the 'reasonableness' test with an absolute requirement to undertake a meter reading every twelve months.

For example, there are a number of items that have emerged recently that are likely to have an impact on our future expenditure requirements, but it is too early to have completed an assessment of the impact. These items are:

- **carbon tax and associated policies** - in the time available since confirmation of this policy package, we have been unable to comprehensively assess the impact of new obligations and costs on our operating expenditure. However, it is likely that there will be some increases in operating expenditure associated with the tax itself and also due to the new policies as part of the 'clean energy package'. We will continue to investigate these and provide supplementary forecasts to the Authority as soon as the legislation is passed and we have assessed the impact
- **Energy*Safety* measures** - Energy*Safety* advised Western Power in July and August 2011 of a number of proposed legislative changes that will affect Western Power including:
  - amendment to Section 18C and 19B of the *Energy Coordination Act 1994*
  - proposed amendments to the *Electricity (Supply Standards and System Safety) Regulations 2001*
  - proposed amendments to the *Electricity (Licensing) Regulations 1991*
  - proposed amendments to the *Electricity Regulations 1947*

We are in the process of responding to Energy*Safety* on the proposed amendments. We have not yet had an opportunity to fully assess the impact of the proposed changes. However, we anticipate costs to largely impact our operating expenditure in relation to training, reporting and compliance monitoring.

Where further changes in scope or obligations arise we will use the relevant recovery provisions of the Access Code and access arrangement, which will allow costs to be passed through to customers in the AA4 period[104] or will trigger a reopening of the access arrangement[105].

Adjusting for changes in scale

We have increased our operating expenditure to reflect the cost impacts of a growing network and customer base. This has been done by applying scale escalation to recurrent network costs from 2011/12 onwards (starting from 2010/11 base year). We have escalated the cost of all network operations and maintenance activities by the average annual growth rate of 3.42% and the cost of call centre and metering activities by the annual average customer growth rate of 2.43%. Growth rates have been calculated by adopting the accepted parameters employed in the scale adjustment method used by the Australian Energy Regulator (AER)[106].

The network growth rate reflects the growth in the costs to operate and maintain the network attributable to the forecast growth of:

- 1.24% annual increase in line length
- 5.93% annual increase in zone substation capacity
- 3.1% annual increase in the number of feeders

[104] If related to an unforeseen event under section 6.6 – 6.8 of the Access Code or Technical Rule changes under section 6.9 – 6.12 of the Access Code.
[105] If related to a trigger event under section 4.37 of the Access Code.
[106] Appendix J, section J.63, *Final decision – appendices Victorian electricity distribution network service providers distribution determination 2011-2015*, AER, October 2010.

This provides a composite annual average network growth rate of 3.42% during AA3.

Western Power's customer growth rate reflects the growth in residential and commercial customer numbers outlined in chapter 6 of this document. The forecast growth in customer numbers over the AA3 period is an annual average increase of 2.43%.

Table 29 shows the impact of scale escalation on recurrent network operating expenditure.

Table 29: Impact of network growth and customer growth on recurrent network operating expenditure

($ million real at 30 June 2012)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Network growth	7	16	25	34	44	53	173
Customer growth	1	1	2	3	3	4	13
Total scale escalation	**8**	**18**	**27**	**37**	**47**	**57**	**186**

Recurrent cost forecasting method is appropriate

The method we have used to forecast recurrent costs is consistent with the approach used by other transmission and distribution network businesses. This method has been accepted in a range of other regulatory decisions[107]. The AER has commented that:

> *The AER considers that given the incentives to minimise costs in the regulatory regime, the revealed costs of a DNSP [Distribution Network Service Provider] are likely to be a reasonable approximation of efficient costs in the circumstances of that DNSP for the scope of work undertaken.*
>
> *The use of a base year approach is an accepted regulatory practice which has been implicitly accepted by the Victorian DNSPs.*[108]

This is further noted by the Australian Energy Market Commission (AEMC), in its policy rationale underpinning the National Electricity Rules Chapter 6A framework:

> *While informed opinions may differ on what are efficient costs, costs of a prudent operator or realistic expectation of forecast demand and input costs in the circumstances facing a regulated entity, those matters can be tested by reference to objective evidence drawn from history….. At the end of the period, the actual costs in this period may be used as a basis for establishing the reasonableness of the cost estimates provided by the TNSP in the subsequent regulatory control period.*[109]

[107] The scale escalation approach has been accepted by the AER in a number of decisions, the most recent of which are the Victorian distribution network service providers' 2011-2015 decision, ETSA Utilities 2010-15 decision, ACT and New South Wales electricity distribution network service providers' 2009-2014 decision and the TransGrid decision and transmission determination 2009-2014. In addition, Ofgem produced the 'Electricity Distribution Price Control Review Methodology and Initial Results Paper 47a/09' which details the merits of the method.
[108] p316, *Final decision – appendices Victorian electricity distribution network service providers distribution determination 2011-2015*, AER, October 2010.
[109] p53, *AEMC Rule Determination – National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No.18*, AEMC.

7.2.2 Non-recurrent network costs

We have identified seven non-recurrent activities with associated costs totalling $280 million[110] over AA3.

Non-recurrent operating expenditure includes activities that are one-off, project based or for a discrete time period. Consequently, scale escalation has not been applied to costs for these activities. They are added to the operating expenditure forecasts once the forecasts have been adjusted for scale but before input cost escalation.

Non-recurrent cost forecasts for the AA3 period comprise:

- **network control services**[111] – this is a program that provides payments to generators to operate in constrained sections of the network to enable Western Power to efficiently defer major capital investments in capacity expansion. They provide a net benefit to our customers whilst efficiently minimising costs. The AA3 network control service payments have been determined by:
  - forecasting the megawatts (MW) required in each financial year as per the demand forecasts and generation planting scenarios
  - estimating the balance of fuel costs to be paid by Western Power
  - the balance of capacity credits to be paid by Western Power
  - forecasting capacity credits to be paid by the Independent Market Operator (IMO)
- **smart grid** – this is a program of work that will introduce smart technologies into the network to allow customers to better manage their electricity consumption and allow Western Power to achieve network planning and operating efficiencies over time. Smart grid is treated as non-recurrent for the AA3 period as it is a specific program of work. Once the use of smart technologies is established and becomes business as usual, we expect that the costs associated with this program will become more stable and will be captured as a recurrent network cost in subsequent access arrangement periods
  - In AA3, we will incur non-recurrent operating expenditure for:
    - managing smart meters
    - smart grid communications systems
    - smart grid network management and IT systems
    - smart grid customer programs for peak demand and energy efficiency management
    - community engagement, education and demand management programs
- **removing redundant assets** – this involves the removal of transmission lines that are no longer in service. It satisfies our safety obligations under section 25(1) (a) of the *Electricity Act 1945*[112] by reducing the potential for public safety incidents, for

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[110] The $280 million value includes expensed indirect costs and real escalation, therefore will not reconcile directly with Table 27.

[111] While providing network control services is a recurrent activity, the location and the magnitude of services and the corresponding expenditure will vary on a project by project basis. Therefore it is appropriate for the expenditure to be considered non-recurrent for the purposes of forecasting. This is consistent with these services being a substitute for capital expenditure projects.

[112] This section requires Western Power to "at all times maintain all service apparatus belonging to the network operator which is on the premises of any customer, in a safe and fit condition for supplying electricity".

example unassisted pole failures, on assets that are no longer maintained. Forecasts for identified, specific projects have been individually costed

- **field survey data capture project** – in AA2, we commenced a program of physical field audits of its assets to ensure data accuracy. In AA3 we will complete this program across the entire network. The AA3 forecast for the field survey data capture project has been determined on the basis of market pricing for this activity obtained through the competitive tenders for the initial pilot programs conducted during AA2
- **guaranteed service level payments** – these are payments made to customers when specific service standards are not met. They include payments for extended outages and not meeting planned outage notification and customer complaint requirements. These are forecast on an annual basis to allow for consideration of factors affecting service levels, for example the size of the works program, weather expectations, investment in customer services areas
- **design and planning costs** – these are costs that relate to quotations provided to distribution customers for connection applications. This work type includes customer-driven design and estimation works for projects that do not proceed. This work is forecast using a bottom-up build, given that is affected by factors such as the nature of works forecast in the works program, the size of the connections queue and speed with which applications are processed
- **non-revenue cap services** – these are customer-driven requests that are provided on a fee-for-service basis rather than funded through the revenue cap. These are forecast on an individual basis as they are not directly affected by the number of customers or the size of the network

Further detail about the forecasts for transmission and distribution non-recurrent expenditure is set out Appendix A: AA3 capital and operating expenditure report.

7.2.3 Indirect network costs

We incur costs that are not directly related to the network works program but are incurred as a result of the works program. These are referred to as ‘indirect network costs’ and cover project management and coordination, as well as maintaining computers and facilities for operational staff. These costs are allocated to activities and expensed or capitalised using the cost and revenue allocation method provided in Appendix E.

For AA3 we have forecast these costs separately for the activities which are fixed or variable based on the size of our works program. We have considered our actual 2010/11 costs and known step changes.

- **Fixed activities account for 92.7% of the AA3 forecast indirect network costs**. We hold these fixed activities constant at 2010/11 levels in real terms with adjustments made for known step changes over the period.
- **Variable activities account for 7.3% of the AA3 forecast indirect network costs**. We attribute each variable element to a relevant scale driver (e.g., customer numbers, employees and network scale) to forecast growth in the activity over the period.

7.2.4 Corporate costs

We allocate corporate costs to the transmission and distribution cost bases in accordance with our cost and revenue allocation method provided in Appendix E.

The method used to forecast corporate costs for the AA3 period varies according to the type of expenditure and its function. A summary of the methods used to forecast different corporate costs is provided below.

Business support divisional costs

Forecasts are based on an assumed continuation of our current staffing requirements (with minor adjustments). We have adjusted for increased staffing to support a higher level of recruitment activity and increased business planning associated with the larger forecast works program over AA3.

Insurance

Forecasts of insurance costs are based on the analysis and aggregation of our individual insurance cost forecasts for AA3. This includes our costs of insurance for public liability, self insured losses, fire and perils/property, contract works, broker fees and workers compensation costs. Specifically:

- **public liability insurance** – ongoing bushfire losses are expected to have a significant impact on our premiums – forecasts incorporate an annual increase of 11.5% (based on broker’s guidance and an expectation of low to moderate losses)
- **self insured losses** – forecasts for bushfire losses remain flat and non-bushfire losses include 5% per year increase
- **fire and perils/property** – forecasts incorporate a 5% per year increase
- **contract works** – this covers the testing and commissioning of works performed by Western Power, the Alliances and authorised third party contractors – our forecasts remain flat over AA3
- **broker fees** – our current service agreement expires in 2011/12 and increases are anticipated – following renegotiation of our agreement, a one-off increase of 10% is applied in 2012/13 and forecasts remain flat thereafter
- **workers compensation costs** – our forecasts incorporate bi-annual increases of 5% for wages and 5% for premiums

Rates and taxes

Land tax forecasts for 2012/13 are based on 2010/11 actuals with adjustments to reflect planned acquisitions and disposals, and an increase in land values. For land tax forecasts beyond 2012/13, advice received from the Valuer General's Office is that increases of 8% - 10% per year is advisable for budgeting purposes. Based on this advice and assumed future acquisitions, a 10% increase has been used.

Local government rate equivalence tax forecasts are based on a combination of advice received from the Valuer General's Office, historical trends and future land acquisitions. Fire & Emergency Services Authority (FESA) levy forecasts are based on a continuation of historical trends.

Energy*Safety* levy

We (along with other industry participants) pay a levy to the safety regulator Energy*Safety* to fund energy safety initiatives.

The proportion that we pay is determined by the Office of Energy's costs for the levy and our customer numbers as a percentage of total industry connections. Forecasts for AA3 have been developed on the assumption that our percentage of customer numbers remains constant relative to total industry connections, and that the Office of Energy's costs are predominantly labour-driven and so will escalate accordingly.

7.2.5 Adjusting for forecast movements in the market price of labour and materials

We have incorporated the forecast movements in the cost of labour and materials in to our operating expenditure forecast. This accounts for 6.6% of total operating expenditure across AA3. Table 30 sets out the impact of input cost escalation in real terms on our operating expenditure over AA3.

Table 30: Impact of input cost escalation on operating expenditure[113]

$ million real at 30 June 2012	2012/ 13	2013/ 14	2014/ 15	2015/ 16	2016/ 17	Total AA3	% of total operating expenditure
Labour escalation	8.1	19.7	35.0	48.8	65.9	177.5	6.5%
Materials escalation	-0.1	0.0	0.2	0.3	0.4	0.9	0.0%
Total input cost escalation	**8.1**	**19.7**	**35.2**	**49.1**	**66.3**	**178.4**	**6.6%**

As with any other business, we face movements in the cost of labour and materials. Recent history shows many of these costs growing faster than general price movements in the economy as measured by the consumer price index. We expect that this trend will continue in the foreseeable future.

We procure labour and materials through rigorous competitive tendering and labour force wage negotiations. These ensure our costs for these inputs are efficient by reference to their market price. We adopt prudent contracting practices and advance purchasing to reduce exposure to market price movements. Through these practices, we will continue to efficiently minimise our costs[114] by constraining our input cost growth forecasts to no more than the movement of the market price for those inputs.

We have therefore escalated forecast capital and operating expenditure for forecast movements in input costs. The forecast of input cost escalation was independently developed the Competition Economists Group (CEG) and Macromonitor.

Escalation forecasts were provided for:

- labour
- materials – steel, copper, aluminium and oil

[113] Note that these impacts are indicative, as escalation necessarily compounds and when viewed at this disaggregated level is affected by the ordering in which escalation is applied.
[114] As required by section 6.40 of the *Electricity Networks Access Code 2004*.

CEG's forecasting method and the resulting cost escalators applied to Western Power's investment forecasts are provided in appendix W.1 and W.2. A summary of the results is provided below.

Labour cost escalation

We commissioned expert forecasters Macromonitor[115] to provide labour escalation forecasts specifically for the Western Australian electricity, gas, water and waste (EGWW)[116] sector. The use of expert labour forecasts is consistent with the method the Authority approved for our current access arrangement period labour escalation forecasts.

In determining the appropriate labour escalation forecasts, Macromonitor developed weighted average forecasts for EGWW labour hired through enterprise bargaining requirements, individual contracts and awards. The geographic isolation of Western Australia's labour market and the unique labour constraints affecting this market result in labour escalation that exceeds the rest of Australia.

Table 31 shows Macromonitor's labour escalation forecast.

Table 31: Labour escalation factors

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Labour	1.9%	1.5%	3.1%	3.7%	3.1%	3.1%

Materials cost escalation

CEG's method for forecasting materials input prices derives escalation factors based on futures prices, where these are available and sufficiently liquid. This forecasting method imputes the market's expectations of future materials prices from the current futures prices on these commodities over different futures periods (see Appendix W.1).

> *In CEG's opinion, the most reliable forecast for input prices is provided by prices determined in the futures market – provided that the relevant market is sufficiently liquid. That is, the most reliable predictor on a particular date in the future is the price at which market participants are willing to commit to trading on that day. If there was a better estimate of future prices, then investors could expect to profit by buying/selling futures until today's futures price reflected the best estimate of spot prices of the relevant future date.*[117]

Where futures prices are not available, are insufficiently liquid or are too short-dated to extend over the necessary forecast period, CEG has supplemented these with the views of expert forecasters obtained from Consensus Economics.[118]

Table 32 shows CEG's materials escalation factors.

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[115] *Forecasts of Labour Costs – Electricity, Gas, Water and Waste Services Sector, Western Australia, Report prepared for Western Power*, Macromonitor, July 2011.
[116] Using the Australian Bureau of Statistics industry classification.
[117] p11, *Escalation Factors: A report for Western Power*, CEG, August 2011.
[118] section 4, *Escalation Factors: A report for Western Power*, CEG, August 2011.

Table 32: Materials real escalation factors[119]

Material type	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Steel	-1.3%	-2.6%	0.7%	4.1%	3.4%	2.7%
Copper	-5.3%	-0.8%	-0.8%	-1.7%	-2.4%	-3.1%
Aluminium	-0.9%	2.8%	4.1%	3.9%	3.3%	2.6%
Oil	-0.2%	2.1%	1.6%	1.0%	0.7%	0.4%

The materials escalation forecasting method CEG has adopted is the current standard for recent Australian energy network regulatory determinations.[120]

Application of expert escalation factors to forecasts

We have applied CEG's and Macromonitor's forecast input cost escalators to our capital and operating expenditure forecasts by identifying the relevant inputs for cost escalation forecasting (labour, steel, copper, aluminium and oil) and developing appropriate weightings. This process included:

- forecasting our capital and operating activities for each year of AA3 split into four cost components: internal labour, external labour, materials and vehicle fleet
- developing detailed materials input cost weightings for each regulatory category of expenditure by:
  - determining the type and proportion of activities in each operating expenditure regulatory category
  - assessing the breakdown of each activity and each asset into its key input materials based on the shares of reported costs in our 2010/11 base year

The materials weightings have been informed by data maintained by our procurement team. We procure materials for our staff and contractors. This consolidated approach to competitively procuring materials allows costs to be efficiently minimised by realising economies of scale in procurement and being able to monitor changes in the market prices of these inputs and the correlation of these changes to their underlying input material spot prices.

We have not applied real input cost escalation to inputs that are not expected to increase by more than CPI. We have identified vehicle and fleet costs, SCADA and communications infrastructure and IT materials as unlikely to increase by more than CPI.

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[119] The impact of the carbon tax has not been included as modelling was not available at the time of forecasting labour and materials price movements. It is expected that this tax will affect the price of our inputs and therefore the cost of maintaining and expanding the network. We are continuing to assess the impacts. Impacts on our AA3 forecasts will be provided when they are available.

[120] See for example:

- p36-46, ElectraNet *transmission determination 2008–09 to 2012–13*, AER, April 2008.
- Appendix L, *New South Wales distribution determination 2008–09 to 2012–13*, AER, April 2009.
- p78-87, *Final decision: Jemena Gas Networks: Access arrangement proposal for the NSW gas networks 1 July 2010–30 June 2015*, AER, June 2010.
- Appendix K, *Victorian electricity distribution network service providers: Distribution determination 2011–2015*, AER, October 2010.

7.3 Overview of required AA3 operating expenditure

In AA3, we forecast $2.714 billion of operating expenditure to deliver covered services. The majority of this expenditure (68%) is for the recurrent operating and maintenance activities we undertake to meet our service standard and compliance obligations. The remaining share is driven by non-recurring network activities and corporate costs as detailed in section 7.4.3, 7.5.4 and 7.6.

The $2.714 billion operating expenditure can be broken down as follows:

a) recurrent network costs ($1.850 billion), comprising:

- **preventative maintenance** ($746 million) – to maintain expected asset lives and network performance through the proactive inspection and identification and treatment of poor performing assets that are likely to fail
- **corrective maintenance** ($697 million) – to rectify unsafe conditions as a result of extreme weather events, ageing assets, failed assets and other reactive events
- **network operations** ($257 million) – to provide communication within the Western Power Network, allow access to the network for maintenance and capital works and maintain reliability through network monitoring and network switching operations
- **customer services and billing** ($150 million) – to maintain service to customers through our call centre, billing services, and repair and maintenance of meters

b) non-recurrent network costs ($280 million)[121]

To deliver project specific activities including procuring network control services (use of generators and demand side management) to efficiently defer capital expenditure, the field survey data capture project to improve our data on existing network assets, removal of redundant transmission assets to improve safety, customer service payments, introduction of smart meters to help better manage electricity consumption and providing non-revenue cap services to customers upon request.

c) corporate costs ($584 million)

To provide recurrent administrative activities and business support functions to run the business (including insurance, rates, taxes and Government payments).

Figure 52 shows the contribution of each of these cost types to the total required operating expenditure over AA3.

[121] Note that non-recurring costs differ from changes in obligations or Western Power's operating environment that will become recurrent costs. The former is individually forecast on a business case basis whereas the latter is forecast by adjusting the recurrent cost base in the relevant year for each change prior to applying scale and input cost escalation.

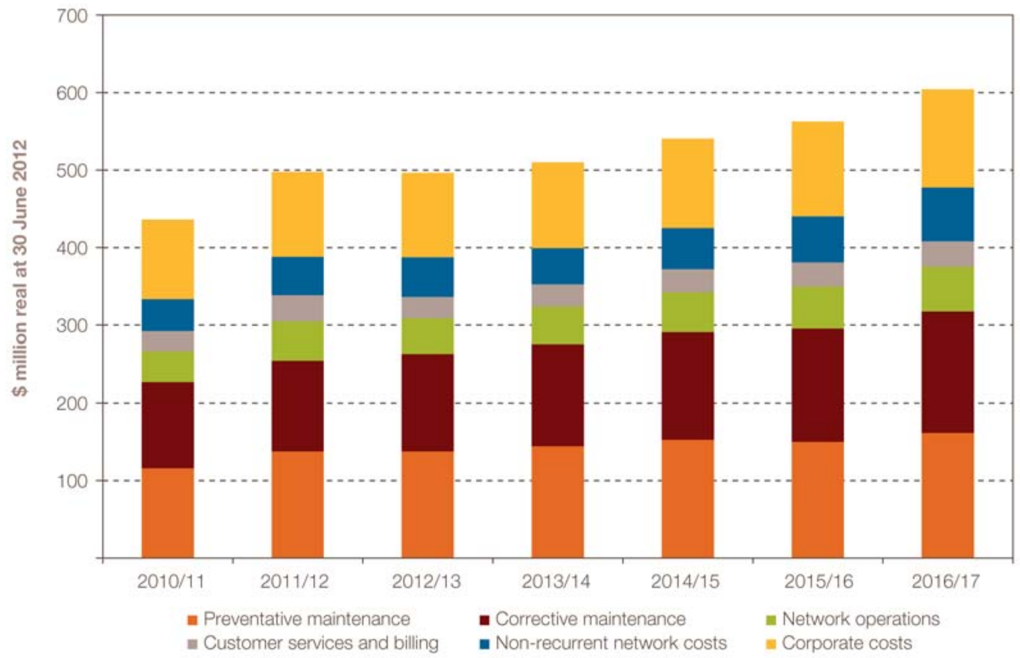

Figure 52: Total operating expenditure

7.4 Transmission operating expenditure

We will require $456 million of transmission operating expenditure for the AA3 period (see Table 33).

Table 33: Transmission operating expenditure by category

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Maintenance	44.5	46.5	49.0	51.6	55.3	246.9
Operations	25.6	26.8	28.5	30.1	32.3	143.3
Other	13.9	7.2	11.0	14.0	20.1	66.3
Transmission operating expenditure	**84.0**	**80.6**	**88.5**	**95.7**	**107.7**	**456.5**
Less non-revenue cap services	3.1	3.2	3.4	3.6	3.9	17.2
Total transmission operating expenditure	**80.8**	**77.4**	**85.1**	**92.1**	**103.8**	**439.3**

Transmission operating expenditure provides for:

- **maintenance** ($247 million) – this covers asset inspections, monitoring and repairs carried out to reduce the risk of power outages due to critical plant and equipment failure (see section 7.4.1).
- **operations** ($143 million) – this covers the network operations function that manages the day to day operation of the transmission network, and the SCADA systems that provide the communications and control infrastructure for operating the network (see section 7.4.2)

- **other** ($66 million) – this covers network control services and removal of redundant transmission lines (see section 7.4.3)

Figure 53 shows the composition of the $457 million we will spend during AA3 to operate and maintain our transmission network.

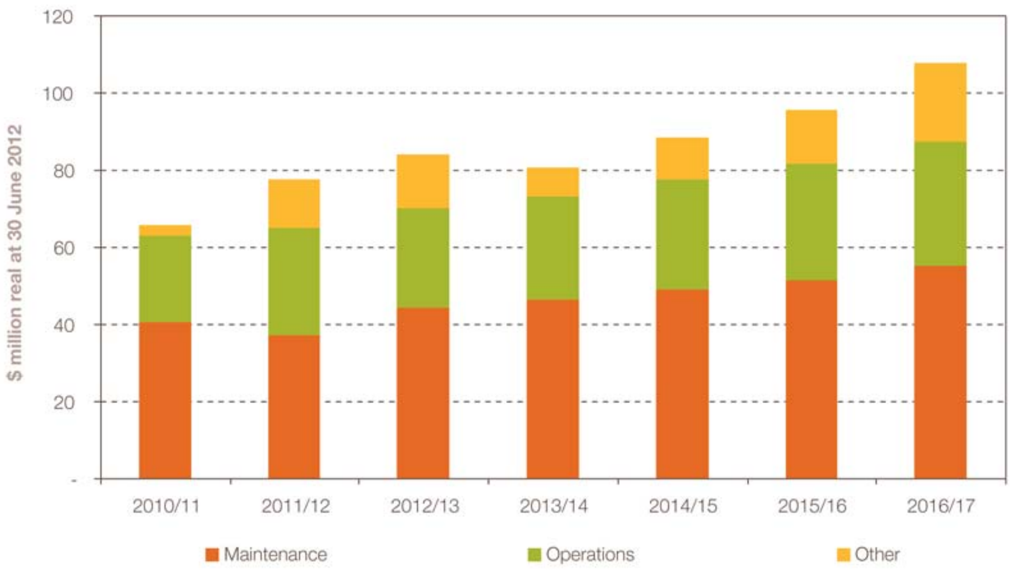

Figure 53: Transmission operating expenditure

The forecast transmission operating expenditure incorporates the amount required to satisfy legal obligations relating to transmission network operation.

Transmission operating expenditure obligations

Western Power is obligated to maintain its network assets to provide covered services to the appropriate level of quality and in a safe manner in accordance with the following key legislation:

Section 25(1) of the *Electricity Act 1945*
A network operator shall:

a) at all times maintain all service apparatus belonging to the network operator which is on the premises of any consumer, in a safe and fit condition for supplying electricity;

b) in the actual supply of electricity to the premises of a consumer take all reasonable precautions in order to avoid the risk of fire or of other damage on the said premises to the position on the said premises where the electricity passes beyond the service apparatus of the network operator;

(c) from the time when the network operator begins to supply electricity through a distributing main as continuous current, maintain such supply constantly without a change of polarity;

Regulation 10(1) of the *Electricity (Supply Standards and System Safety) Regulations 2001*
A network operator must ensure that each prescribed activity is, so far as is reasonable and practicable, carried out in such a way as to:

a) provide for the safety of persons, including employees of and contractors to the operator;

b) avoid or minimise the exposure of persons, including employees of and contractors to the operator, to electric and magnetic field effects; and

c) avoid or minimise any damage to property, inconvenience or other detriment as a result of the activity.

Technical specifications including *Australian Standard 7000:2010* *and the other specifications as set out by EnergySafety.*

Reliability and quality of supply - *Electricity Industry Act 2005, Electricity (Network Reliability and Quality of Supply) Code 2005* Clause 10(1)
A transmitter or distributor must, so far as is reasonably practicable, reduce the effect of any interruption on a customer.

Technical Rules Clause 1.8.2 (c) (2)
The Network Service Provider must arrange for: management, maintenance and operation of the transmission and distribution systems to minimise the number and impact of interruptions or service level reductions to Users.

7.4.1 Transmission maintenance

We maintain our transmission network to minimise equipment breakdowns and unplanned interruptions to critical network assets and hence interruptions to the electricity supply. We do this through a combination of asset inspections, repairs, reinforcements and replacements when an asset is no longer economically serviceable.

Inspections and repairs are classed as operating expenditure, while reinforcements and replacements form part of capital investment programs. Our asset management approach is outlined in section 4.4 of this document and in Appendix L.

We deliver maintenance activities through four distinct categories:

1. **preventative routine** ($110 million) – routine asset inspection cycles and equipment tests to predict the onset of asset failure and detect a failure before it has an impact on the asset functions, network reliability (see chapter 5) and/or safety
2. **preventative condition** ($62 million) – scheduled planned maintenance works performed as a result of conditions or defects identified through preventative routine maintenance programs to minimise safety risks, reduce system downtime and improve reliability
3. **corrective deferred** ($61 million) – follow-up works after emergency network repairs using standard workforce patterns to efficiently minimise costs of emergency situations

4. **corrective emergency** ($14 million) – responsive works that are usually as a result of a network emergency to restore supply, ensure safety of the public and personnel and prevent further damage to equipment

Figure 54 shows how our transmission maintenance costs will grow over the AA3 period. This increase is in line with growth in the size of the network and growth in labour and materials costs.

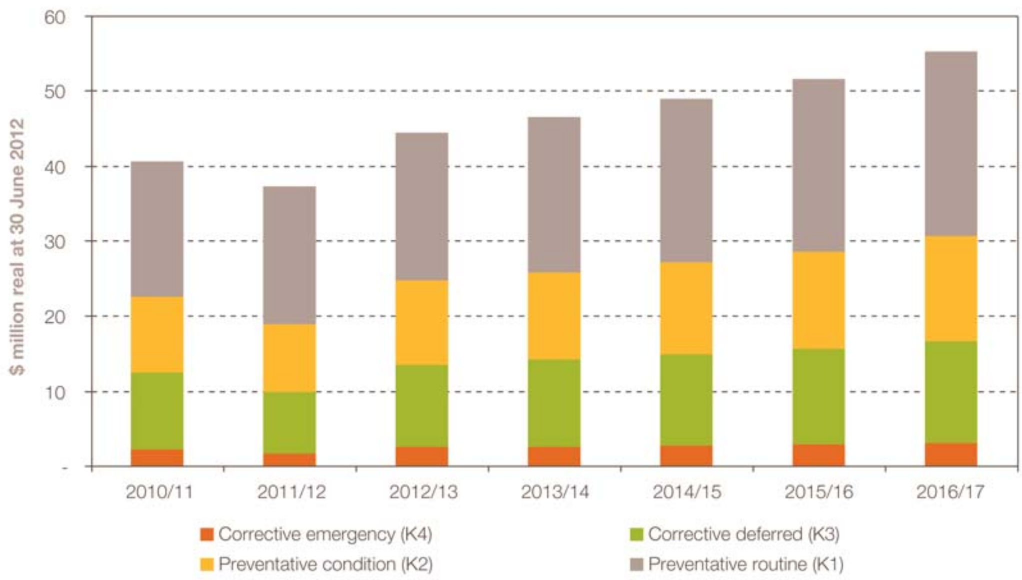

Figure 54: Transmission maintenance operating expenditure

Further detail on transmission maintenance expenditure is provided in Appendix A: AA3 capital and operating expenditure.

7.4.2 Transmission operations

Transmission operations covers monitoring, managing and operating network assets, communication networks and the master control systems. These functions maintain security of the power system so that it can supply the forecast daily load (peak demand and energy), while enabling access to the network (planned outages) for maintenance and connection of new assets.

Transmission operations activities are categorised as:

- **SCADA and communications** ($71 million) – operation and maintenance of the radio network, SCADA and communications systems
- **network operations** ($55 million) – centralised monitoring and control for operation of the transmission network
- **non-revenue cap services** ($17 million) – customer-driven requests provided on a fee-for-service basis that are not recovered through the revenue cap

Transmission network operations are critical to the business achieving its transmission service standard benchmarks (detailed in section 5.5.1 of this document). The network operations function also enables costs to be efficiently minimised in other network activities and across various assets by:

- optimising the use of planned outages by doing as much related work as is practical during the outage
- preserving the life cycle of assets by operating equipment within defined limits

Figure 55 shows how transmission operations costs will grow over the AA3 period. This increase is in line with growth in the size of the network and growth in labour and materials costs.

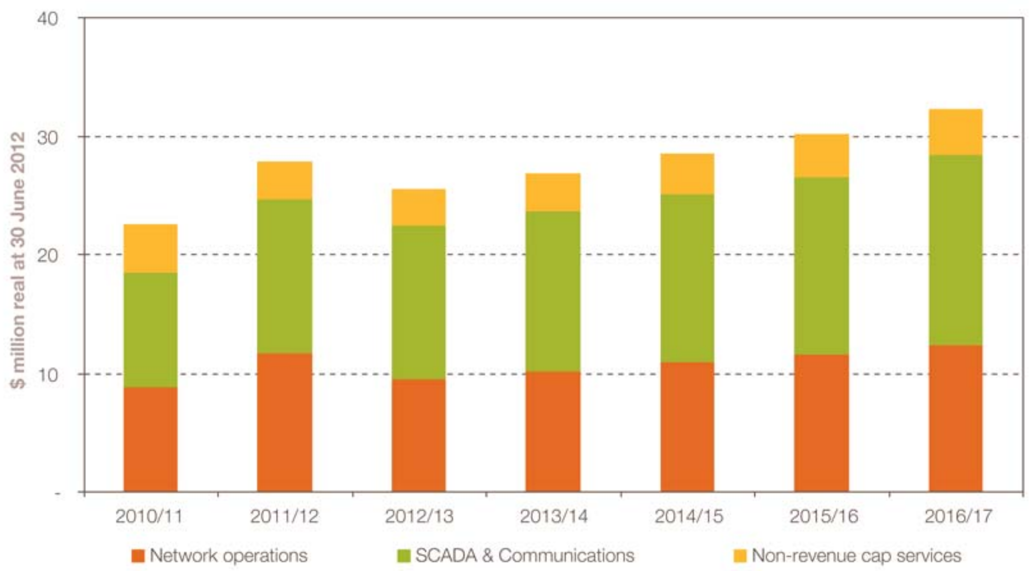

Figure 55: Transmission operations operating expenditure

7.4.3 Transmission 'other'

During AA3 we will incur $66 million for 'other' transmission activities. 'Other' operating expenditure tends to be one-off, project based or for a discrete time period and is therefore not considered recurrent or subject to scale escalation as described in section 7.2.1.

These transmission network activities are shown in Table 34.

Table 34: Transmission 'other' operating expenditure

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Network control services	11.0	4.7	10.2	13.4	20.1	59.4
Removal of redundant transmission assets	3.0	2.5	0.8	0.7	0.0	6.9
Total non-recurring operating expenditure	**13.9**	**7.2**	**11.0**	**14.0**	**20.1**	**66.3**

Network control services ($59 million)

Network control services in AA3 are payments to generators operating in constrained network sections. These payments enable major capital investments in capacity expansion to be deferred and thereby provide a net benefit to customers by efficiently minimising costs over time.

In AA3, four areas will require transmission network support. These are Albany, Geraldton, Goldfields and Pinjar. Using network control services in these areas satisfies the regulatory test under section 9.3 of the Access Code:

> *The regulatory test is an assessment under this Chapter 9 of whether a proposed major augmentation to a covered network maximises the net benefit after considering alternative options.*

Network control solutions are considered an efficient alternative solution to network augmentation in the short term. The network support provided by these generators will ensure compliance with the Technical Rules requirements for voltage regulation and power transfer limits in AA3.

Removal of redundant transmission assets ($7 million)

We will incur costs in AA3 to remove redundant transmission assets to improve public safety. Removing lines and poles that are no longer in service minimises maintenance requirements and public safety risks. This program supports compliance with *Part 4 System Safety* of the *Electrical (Supply Standards and System Safety) Regulations 2001* - Part 4 System Safety.

7.5 Distribution operating expenditure

We require $1.673 billion of distribution operating and maintenance expenditure for the AA3 period (see Table 35).

Table 35: Distribution operating expenditure by category

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3	% of distribution operating expenditure
Maintenance	218.8	229.3	242.0	243.8	262.1	1,196.0	71%
Operations	42.3	43.3	46.5	50.3	54.7	237.1	14%
Customer services and billing	34.3	36.1	38.1	40.0	42.0	190.4	11%
Other	8.0	10.0	10.2	10.4	10.9	49.5	3%
Distribution operating expenditure	**303.5**	**318.7**	**336.8**	**344.4**	**369.7**	**1,673.0**	**100%**
Less non-revenue cap services	14.9	15.3	16.0	16.8	17.9	80.9	5%
Total distribution operating expenditure	**288.6**	**303.4**	**320.7**	**327.7**	**351.9**	**1,592.1**	**95%**

The distribution operating expenditure provides for:

- **maintenance** ($1.196 billion) – asset inspections (and repairs for non-run-to-fail critical assets) carried out to reduce the risk of power outages due to plant and equipment failure (see section 7.5.1)

- **operations** ($237 million) – management of the day-to-day operation of the distribution network, SCADA systems and the operation of new technologies (see section 7.5.2)
- **customer services and billing** ($190 million) – activities to meet our customer service obligations and administer network billing. These include call centre activities, metering, guaranteed service level payments and distribution design and estimation quotation (see section 7.5.3)
- **other** ($50 million) – non-recurring projects that are time-specific, individual project related operating expenditure including network control services and the field data capture survey project (see section 7.5.4)

Figure 56 shows how distribution operating costs will grow over the AA3 period. This increase is a result of the increasing size of the network, growth in customer numbers and growth in labour and materials costs.

Figure 56: Distribution operating expenditure

The forecast distribution operating expenditure incorporates the amount required to satisfy legal obligations relating to distribution network operation.

Distribution operating expenditure obligations

Western Power is obligated to maintain its network assets to provide covered services to the appropriate level of quality and in a safe manner in accordance with the following key legislation:

Section 25(1) of the *Electricity Act 1945*
A network operator shall:

a) at all times maintain all service apparatus belonging to the network operator which is on the premises of any consumer, in a safe and fit condition for supplying electricity;

b) in the actual supply of electricity to the premises of a consumer take all reasonable precautions in order to avoid the risk of fire or of other damage on the said premises to the position on the said premises where the electricity passes beyond the service apparatus of the network operator;

c) from the time when the network operator begins to supply electricity through a distributing main as continuous current, maintain such supply constantly without a change of polarity

Safety – Regulation 10(1) of the *Electricity (Supply Standards and System Safety) Regulations 2001*
A network operator must ensure that each prescribed activity is, so far as is reasonable and practicable, carried out in such a way as to:

a) provide for the safety of persons, including employees of and contractors to the operator;

b) avoid or minimise the exposure of persons, including employees of and contractors to the operator, to electric and magnetic field effects; and

c) avoid or minimise any damage to property, inconvenience or other detriment as a result of the activity

Technical specifications - including Australian Standard 7000:2010 *and the other specifications as set out by EnergySafety.*

Reliability and quality of supply - *Electricity Industry Act 2005, Electricity (Network Reliability and Quality of Supply) Code 2005* Clause 10(1)
A transmitter or distributor must, so far as is reasonably practicable, reduce the effect of any interruption on a customer.

Technical Rules Clause 1.8.2 (c) (2)
The Network Service Provider must arrange for: management, maintenance and operation of the transmission and distribution systems to minimise the number and impact of interruptions or service level reductions to Users.

7.5.1 Distribution maintenance

Maintenance activities are an integral element of asset management and will cost $1.196 billion over AA3.

Expenditure in distribution maintenance is required to maintain performance in service standards mainly by reducing the risks and consequential impact of power outages due to plant/equipment failure. This is achieved through a combination of asset inspections, repairs, reinforcements and finally replacements where an asset is no longer economically serviceable. In AA3, we will undertake four key maintenance activities:

1. preventative condition ($332 million) – scheduled planned maintenance works performed as a result of conditions or defects identified through preventative routine maintenance programs to minimise safety risks, reduce system downtime and improve reliability
2. preventative routine ($242 million) – routine asset inspection cycles and equipment tests to predict the onset of asset failure and detect a failure before it has an impact on the asset functions, network reliability and/or safety
3. corrective emergency ($452 million) – responsive works that are usually a result of a network emergency, for example to restore supply, ensure public safety and prevent further damage to equipment

4. corrective deferred ($169 million) – follow-up works after emergency network repairs using standard workforce patterns to efficiently minimise costs of emergency situations

Similar to transmission maintenance (discussed in section 7.4.1), we maintain the critical distribution network assets through a combination of asset inspections, repairs, reinforcements and finally replacements when an asset is no longer economically serviceable.

Figure 57 shows how distribution maintenance operating costs will increase during the AA3 period. This increase is due to the increasing size of the distribution network and growth in labour and materials costs.

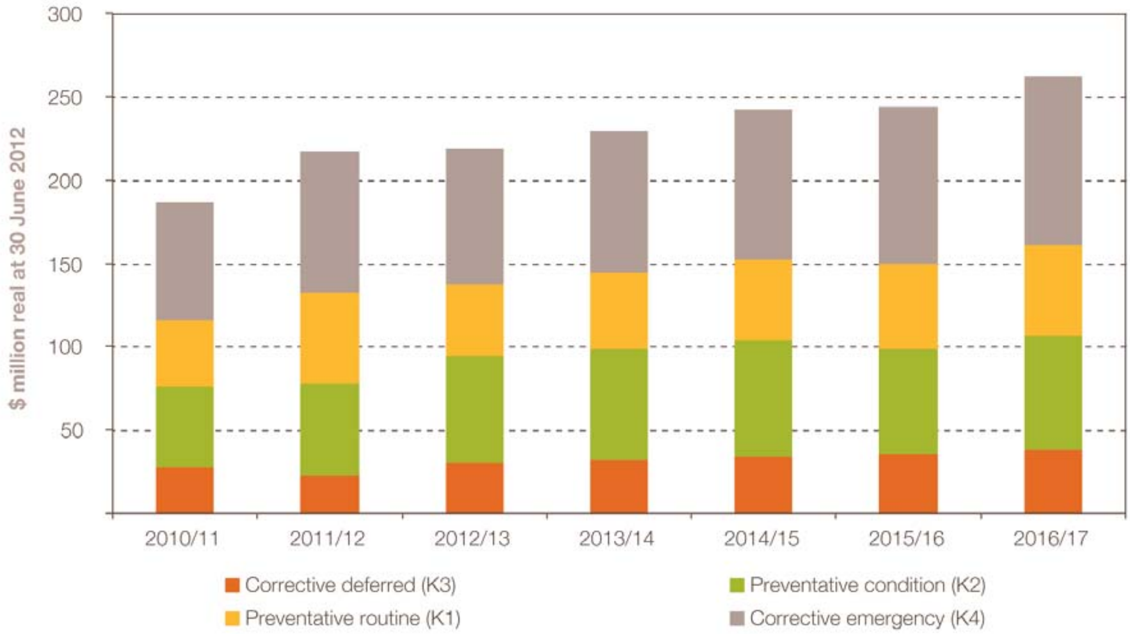

Figure 57: Distribution maintenance operating expenditure

7.5.2 Distribution operations

Distribution operations expenditure covers monitoring, managing and operating distribution network assets, communication networks and the master control systems.

These activities maintain security of the power system so that it can supply the forecast daily load (peak demand and energy), while also enabling access to the network (planned outages) for maintenance and connection of new assets.

Distribution network operation activities are:

- **network operations** ($90 million) – provides centralised monitoring and control over the operation of the distribution network
- **non-revenue cap services** ($81 million) – customer-driven requests for services including high load escorts and extended metering services. These services are provided on a fee-for-service basis and are not recovered through the revenue cap

- **smart grid** ($26 million) – is a program of work which will introduce smart technologies into the network to allow customers to better manage their electricity consumption and achieve network planning and operating efficiencies over time. In AA3, we will incur operating expenditure for managing smart meters, communications systems, network management and IT systems and customer education and engagement
- **SCADA and communications** ($30 million) – operates and maintains the radio network, SCADA and communications systems
- **reliability operations** ($11 million) – operating and maintenance activities that are specialised for distribution network reliability and automation assets

Figure 58 shows how distribution operations costs will increase over the AA3 period. This increase is mainly in network operations and non-reference services and is driven by the growth in customer numbers, the size of the network and growth in labour and materials costs.

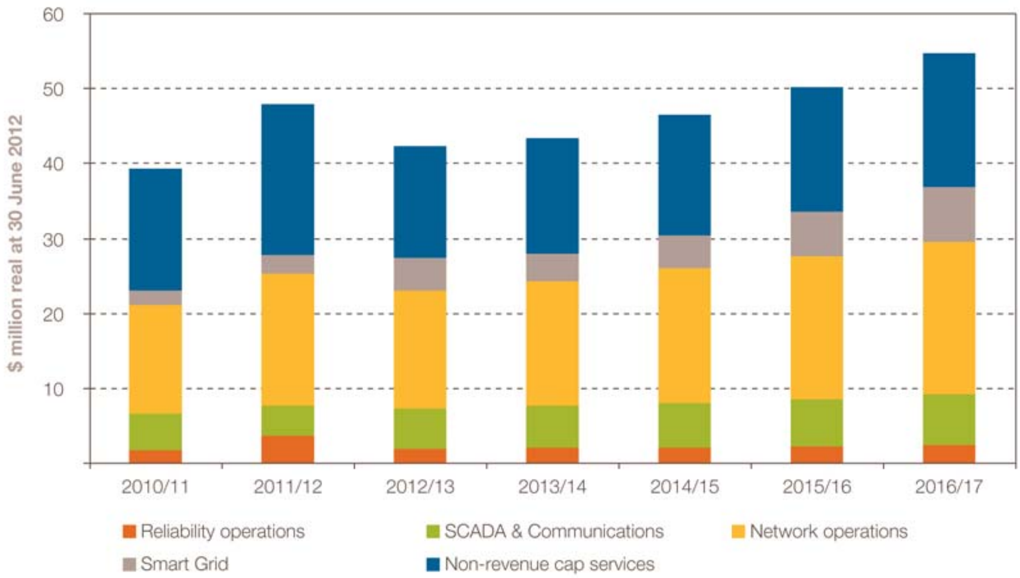

Figure 58: Distribution operations operating expenditure

7.5.3 Distribution customer services and billing

In AA3, we will spend $190 million on customer services related operating expenditure associated with providing covered distribution services. Customer services and billing expenditure comprises operating expenditure for:

- **metering** ($109 million) – relates to operating expenditure for meter reading, meter maintenance and meter testing, which will increase during AA3 in line with growth in customer numbers[122]
- **call centre** ($41 million) – operates as a central ‘gateway’ for handling faults, complaints, fault reporting and general enquiry calls

[122] See chapter 6 of this document for an overview of forecast growth in customer numbers.

The customer services and billing category also includes operating expenditure for the following activities:

- **distribution design and estimation quotations** ($23 million) – relates to quotations provided to distribution customers for connection applications. This work type includes customer-driven design and estimation works for projects that do not proceed[123]
- **guaranteed service level payments** ($17 million) – we are required to make payments to customers that:
  - experience supply interruptions exceeding 12 hours[124]
  - are provided less than the minimum agreed notification period for planned outages
  - have their complaints resolved outside agreed minimum timeframes

Figure 57 shows how operating expenditure on customer services and billing will grow throughout the AA3 period. This increase is a result of growth in the number of customers connected to the network and growth in labour and materials costs.

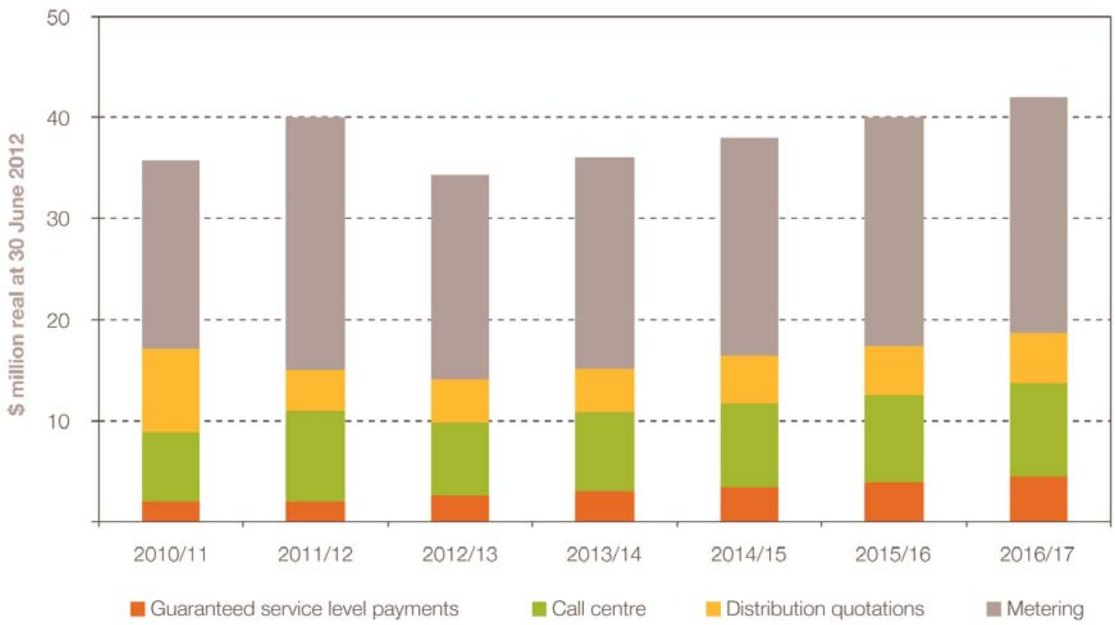

Figure 59: Distribution customer services and billing operating expenditure

Further information in relation to each of these distribution customer services categories is outlined in Appendix A: AA3 capital and operating expenditure report.

[123] Where the works proceed, the costs associated with preparing this quotation form part of project costs.
[124] Previously, costs associated with payments for long duration interruptions were identified in the business support operating expenditure category. To improve transparency and business focus on performance in this area, we have separately identified the expected cost for guaranteed service level payments as a new regulatory category under customer services and billing.

7.5.4 Distribution 'other'

During AA3 Western Power will incur expenditure of $50 million in distribution 'other' operating expenditure (see Table 36). 'Other' operating expenditure is made up of one-off, individual projects occurring for discrete time periods and is therefore excluded from the roll-forward approach described in section 7.2.1. The nature of this category of work means expenditure can fluctuate significantly between years depending on the scope and scale of the component projects.

Table 36: Distribution 'other' operating expenditure

AA3 expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3
Field survey data capture project	5.7	7.6	7.7	7.8	8.1	37.0
Network control services	2.3	2..4	2.5	2.6	2.7	12.6
Total other	**8.0**	**10.0**	**10.2**	**10.4**	**10.9**	**49.5**

Two discrete projects are included in the AA3 forecasts:

- **field survey data capture project** ($37 million) – to expand the pilot program commenced in AA2 to conduct a physical field audit of assets across the entire network. This will ensure data accuracy and improve asset management. The survey will be completed during AA3
- **network control services** ($13 million) – payments to generators operating in constrained sections of the network in Ravensthorpe and Bremer Bay. This will allow costly network augmentation in these areas to be deferred

Appendix A: AA3 capital and operating expenditure report provides a project summary for the field data survey and network control services.

7.6 Corporate operating expenditure

Corporate operating expenditure covers corporate costs, which can be disaggregated between business support divisional costs and corporate-wide expenditure:

- **business support divisional costs** ($384 million) – costs for corporate services to support and sustain the operational divisions of Western Power including divisional expenses for corporate services, strategy and finance, regulation and sustainability and legal and governance
- **corporate-wide expenditure** ($201 million) – corporate-wide expenses are driven by external obligations and include rates and taxes, insurance and the Energy*Safety* levy

Table 37: Corporate operating expenditure

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3	% corporate
Business support divisional costs	72.1	72.2	75.4	80.5	83.3	383.5	66.0%
Corporate-wide expenditure	36.9	38.4	40.0	41.9	43.5	200.6	34.0%
Total corporate	108.9	110.6	115.4	122.4	126.7	**584.1**	**100.0%**

Our corporate operating expenditure forecasts will remain steady over the period, except for increases in insurance, rates and taxes and the market price of labour and materials (see Figure 60).

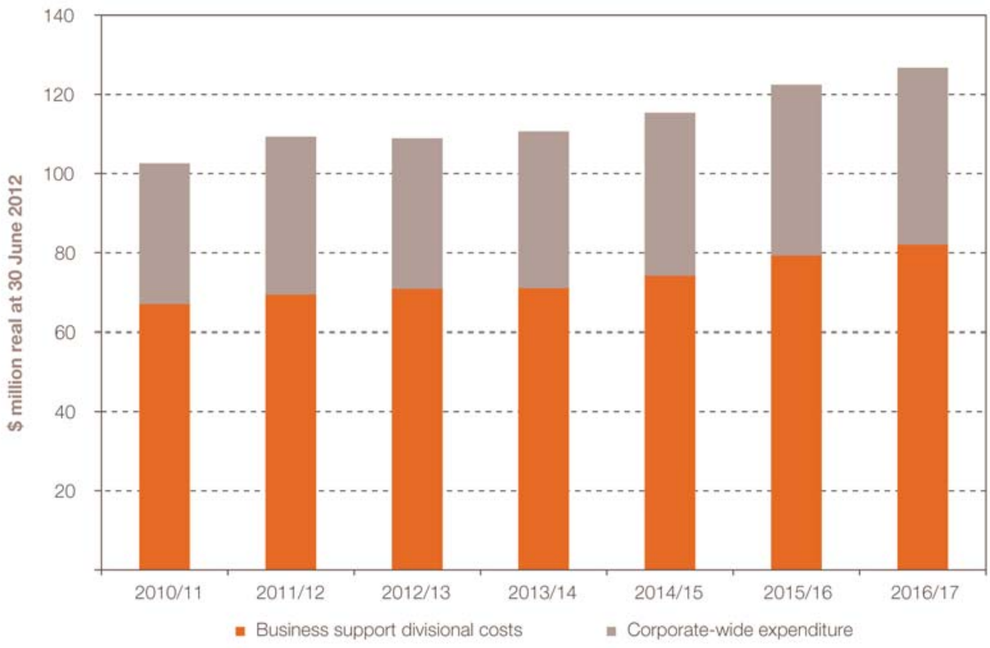

Figure 60: Corporate operating expenditure

The forecast corporate operating expenditure incorporates the amount required to satisfy legal obligations relating to corporate operations.

Corporate operating expenditure obligations

Western Power is obligated to:

- **Pay scheduled rates and taxes** – these are imposed externally, therefore Western Power has little ability to influence them without jeopardising the ongoing operation of its network or breeching statutory obligations
- **Pay the energy safety levy** – as determined by the Office of Energy to fund energy safety initiatives
- **Comply with significant regulatory and legislative obligations** – business support divisional costs include the corporate functions of human resources, safety and health and corporate real estate, which are required to achieve compliance with the *Operational Health and Safety Act 1984*, Building Codes of Australia, *Disability Discrimination Act 1992* and the *Environmental Protection Act 1986*
- **Meet regulatory obligations under the Access Code** – Western Power must be able to provide appropriate corporate services in order to deliver its regulatory requirements
- **Perform financial reporting functions** – to produce audited statutory financial statements and regulatory financial statements, meet State Budget reporting requirements and provide corporate tax return information

The material increases in corporate expenditure items between the start and end of the AA3 period are:

- business support divisional costs, which increase by $11.4 million and comprise 66% of corporate expenditure

- rates and taxes, which increase by $2.7 million and comprise 7% of total corporate expenditure
- insurance, which increases by $3.3 million and comprises 28% of corporate expenditure

The increase in business support divisional costs includes the need for additional staff to manage corporate activities relating to recruitment and business planning, which will increase due to the increase in the works program over AA3.

7.7 Compliance with Access Code requirements

The AA3 forecast operating expenditure complies with section 6.40 of the Access Code as the forecast *includes only those non-capital costs which would be incurred by a service provider efficiently minimising costs*[125].

This is because our forecasts:

- reflect good electricity industry practice as captured in our asset management approach, outlined in section 4.4 of this document and provided in Appendix L: Network Management Plan
- are based on our revealed efficient costs (as set out in section 7.2 of this document) in 2010/11. This is appropriate as the last year of complete actual data in AA2 best reflects the efficient costs of operating and maintaining the network. In particular, actual operating costs in 2010/11 reflect the improvements to maintenance processes, governance and asset management implemented during AA2, as well as the incentives to lower costs within the period under the revenue cap
- have been adjusted to reflect step changes in operations, obligations and non-recurring costs. This ensures known additional costs are provided for, as is required by a network service provider operating in accordance with good electricity industry practice
- reflect the forecast cost impact of growth in the physical network assets and customer numbers by using accepted scale escalation drivers (as set out in section 7.2.1 of this document). This ensures non-capital expenditure will provide for maintaining the current level of network performance in order to meet the service standard benchmarks
- include forecast changes in the market price of labour and materials using independent expert forecasts of these price movements (as set out in section 7.2.5 of this document)
- compare favourably with historical trends and our peers (as shown in section 7.8 and 7.9 of this document)

Our forecasting method is also consistent with the forecasting techniques used by other regulated electricity networks and their regulators.[126] Widespread use of this method reflects the method's ability to provide robust five-year forecasts of the expected recurrent operating

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[125] Section 6.40, *Electricity Networks Access Code 2004.*

[126] See for example:

- p36-46, *ElectraNet transmission determination 2008-09 to 2012-13*, AER, April 2008.
- Appendix L, *New South Wales distribution determination 2008-09 to 2012-13*, AER, April 2009.
- p78-87, *Final decision: Jemena Gas Networks: Access arrangement proposal for the NSW gas networks 1 July 2010 – 30 June 2015,* AER, June 2010.
- Appendix K, *Victorian electricity distribution network service providers: Distribution determination 2011-2015, AER*, October 2010.

expenditure whilst also accounting for specific instances where certain costs may vary year on year due to external factors or initiatives that will deliver net benefits over time.

We have further efficiently minimised our total costs across operating and capital expenditure by:

- pursuing non-network alternatives in the form of network control services where these were found to provide a net benefit through capital investment deferral (see section 7.4.3 and section 7.5.4 of this document)
- employing our smart planning tool to consolidate works and minimise maintenance costs (see section 8.3.2 of this document)
- adopting maintenance inspection bundling practices such as our pole bundled inspection program (see Appendix A: AA3 capital and operating expenditure report)
- commencing the phased introduction of smart meters on a new and replacement basis starting with our three-phase meter population to transition to a remote meter reading capability and thereby avoid manual meter reading costs (see Appendix A: AA3 capital and operating expenditure report)

7.8 Trend analysis

To assess the efficiency of our operating expenditure, we have compared our AA3 forecast operating expenditure with our historical expenditure and examined trends in key cost metrics. This section summarises the results of this trend analysis.

We have also compared forecasts against the operating expenditure of other Australian electricity network businesses. This is summarised in section 7.9.

Figure 61 shows that the historical trend in operating expenditure is consistent with the forecast underlying operating expenditure. The increase above trend in AA3 is due to:

- the step changes, which commence in 2011/12 and are discussed in section 7.2.1
- the increased growth in the scale of our operations in AA3
- an increase in non-recurrent operating expenditure associated with network control services and the introduction of smart grid technology

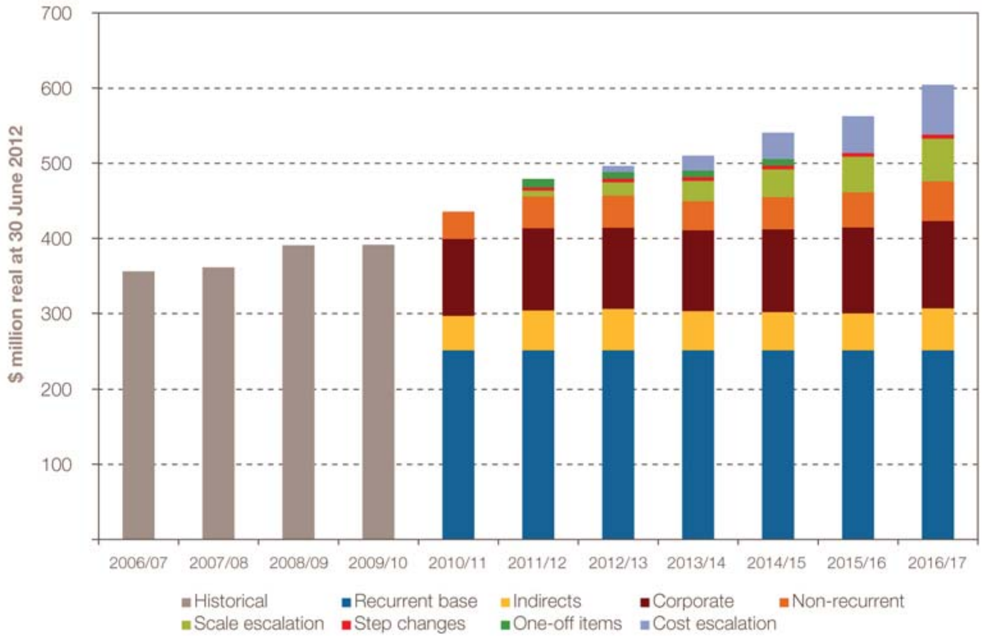


Figure 61: Operating expenditure historical trend

Table 38 shows that the growth in customer numbers and line length is similar in AA3 as in the previous five-year period. However, the number of distribution transformers and the zone substation capacity is forecast to grow at a much higher rate in AA3 than in the previous five years. This is due, in part, to the investment hiatus during AA2. More resources are required to support the increased capital works program in AA3 than were required over the previous five years, resulting in a higher growth in operating expenditure during AA3 than during the preceding five years.

Table 38: Comparison of operating expenditure growth with growth in activity drivers

Activity driver	Annual average growth rate in the five years prior to AA3	Annual average growth rate in the five year AA3 period
Customer numbers	2.5%	2.4%
Line length	1.4%	1.2%
Number of distribution transformers	1.8%	3.0%
Zone substation capacity	4.9%	7.4%
Operating expenditure	4.9%	5.5%

We have also assessed trends in operating expenditure metrics for controllable operating expenditure per customer and per unit of energy consumption. The controllable operating expenditure excludes expenditure associated with non-revenue cap services, licence fees, Energy*Safety* levy, insurance and rates and input cost escalation.

The customer number metric trend analysis is provided as Figure 62 and the energy consumption metric trend analysis is provided as Figure 63.

Figure 62 and Figure 63 indicate that the controllable operating expenditure per customer and per energy consumed is higher in AA3 relative to the previous regulatory periods. The increase is due to the step changes that occur in 2011/12 and the increased capital works program in AA3, which is driven by network scale (measured as line length, feeders and zone substation capacity), growing at a faster rate than customer numbers and consumption. The increased capital works program is due to the major asset replacement and capital expansion program proposed for the AA3 period.

Figure 62 also shows that the controllable operating expenditure per customer is relatively consistent during AA3, decreasing from $443 per customer in 2012/13 to $434 in 2015/16 but then increasing to $444 in 2016/17. Figure 69 (in the next section) shows that our total operating expenditure per customer remains consistent with our network peers.

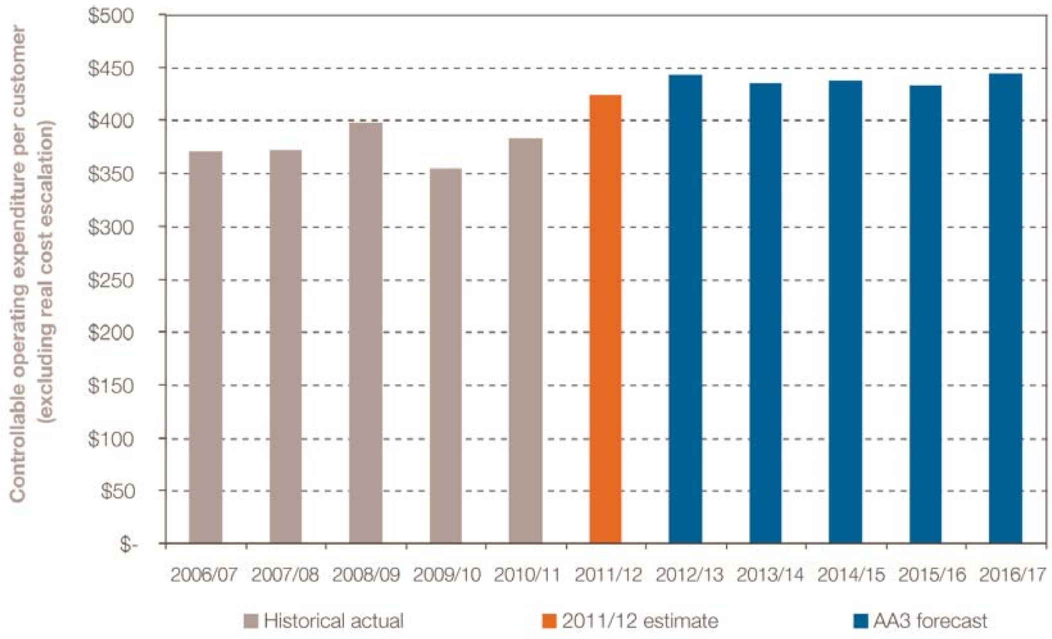


Figure 62: Controllable operating expenditure as a function of customer numbers

Similarly, Figure 63 shows that controllable operating expenditure per unit of energy (MWh) consumed remains relatively consistent during AA3, decreasing from $31.56 per MWh in 2012/13 to $30.64 per MWh in 2015/16 but then increasing to $31.27 per MWh in 2016/17.

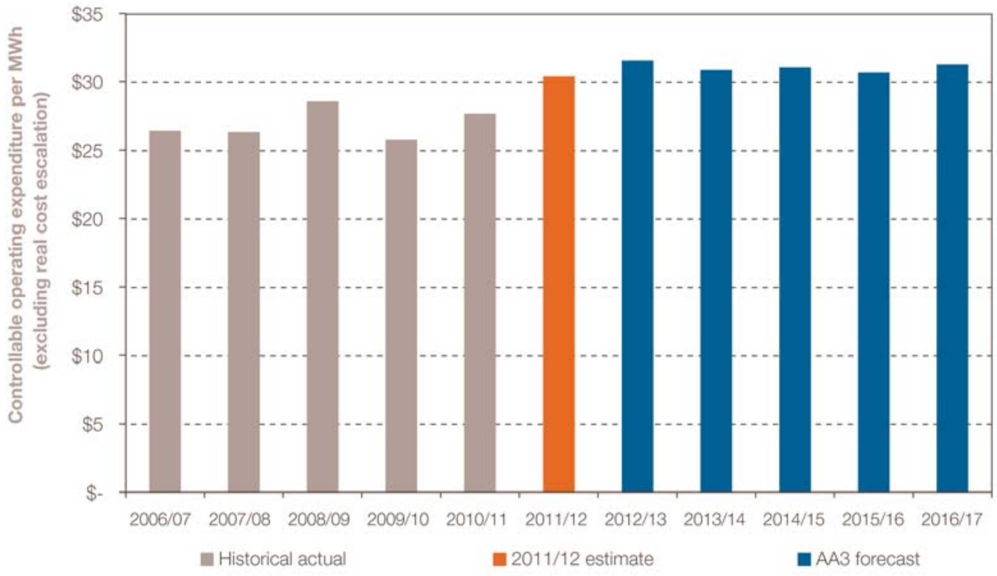


Figure 63: Controllable operating expenditure as a function of energy consumed

7.9 Benchmarking operating expenditure

We have benchmarked our operating expenditure to our peers to indicate how our expenditure compares with other Australian network businesses. The comparisons provided in the following sections are based on the most recent publicly available data for our peers, which is 2008/09[127] for the transmission network businesses and 2009/10 for the distribution network businesses.[128]

While benchmarking data cannot be relied upon as the only source of data to inform operating and maintenance decisions, they do indicate average industry performance. In making these comparisons with our peers, we note that the definition of transmission and distribution varies from jurisdiction to jurisdiction. To ensure that our expenditure is comparable with our peers, we have allocated some expenditure from transmission to distribution.

Additionally, each jurisdiction is subject to different step changes in operating expenditure and different capitalisation policies which are difficult to isolate as part of the benchmarking.

To benchmark our operating expenditure, we have:

- compared our historical operating expenditure for the most recently publicly available data against other Australian network businesses on the basis of key network cost metrics for each network:
  - for transmission – peak demand and line length

[127] Given volatility in the annual spend of transmission businesses, we have used the average for 2006/07 – 2008/09 rather than a point estimate expenditure in 2008/09 for transmission benchmarking. This enables meaningful comparisons across multiple transmission networks.
[128] Actual data was not available for some distribution businesses in 2009/10. For these businesses, the date was estimated based on the best publicly available data.

  - o for distribution – peak demand, line length and customer numbers

- compared our forecast operating expenditure for 2016/17 against the most recent publicly available actual data[129], using the same network cost metrics listed above in order to compare how our own costs move into the future. We note that comparisons of future cost to our peers' current costs are not meaningful because they do not account for any future cost movements that our network peers anticipate
- compared our historical and forecast operating expenditure against that which has been recently approved for other Australian network business in recent regulatory decisions (or submitted by the businesses where a decision is pending). Where enough forward looking data is available, this helps overcome the issue of accounting for our network peers' anticipated cost movements in our comparative analysis

Transmission operating expenditure

Our transmission operating expenditure in 2008/09 was below average compared with the other transmission businesses on the basis of peak demand and line length, as shown in Figure 64 and Figure 65, respectively.

Figure 64 indicates that transmission operating expenditure as a function of peak demand decreases as peak demand increases. The peak demand on our network is currently lower than many of our peers. Despite the forecast increase in peak demand over the AA3 period, the peak demand on the Western Power Network remains low relative to other Australian transmission networks.

Our transmission operating expenditure as a function of peak demand increases from 2008/09 to 2016/17. This is because increases in operating expenditure are driven by growth in labour costs (which average 2.7% per year) and our increased work program in relation to capacity expansion and security, which will increase in AA3 compared to previous access arrangement periods. Our composite network scale escalator (comprising line length, zone substation capacity and number of feeders) averages 3.4% per year. Peak demand is forecast to only grow by an average of 3.2% per year during AA3. Increased use of transmission network control services as an operating solution to efficiently alleviate network constraints also contributes to this increase.

[129] Actual data was not available for some distribution businesses in 2009/10. For these businesses, the data was estimated based on the best publicly available data.

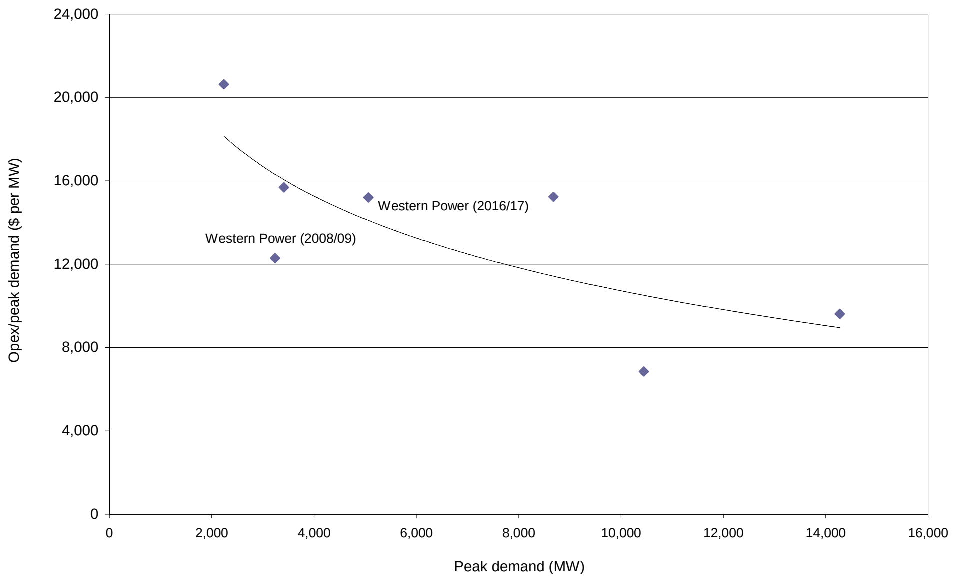


Figure 64: Comparison of transmission operating expenditure as a function of peak demand against peers, 2008/09

Figure 65 indicates that transmission operating expenditure as a function of line length is relatively consistent, regardless of line length. Our transmission operating expenditure as a function of line length is low relative to the other Australian transmission businesses in 2008/09. The increase by 2016/17 is due to the increase in line length (which averaged 1.2% per year during AA2) while our key operating expenditure drivers of labour cost growth and network scale growth are exceeding this. Despite this increase, the ratio remains comparable with the other transmission businesses.

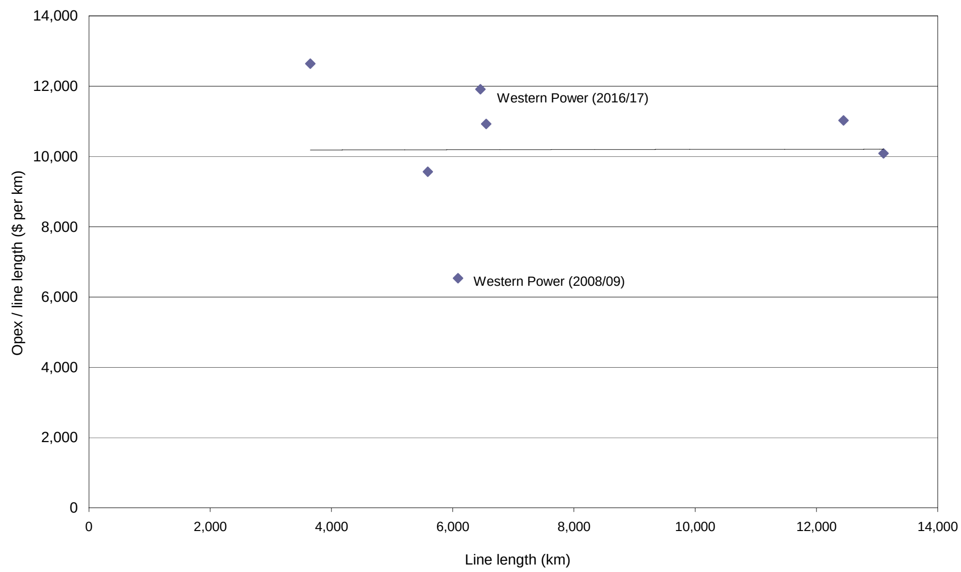


Figure 65: Comparison of transmission operating expenditure as a function of line length against peers, 2008/09

Figure 66 shows how our transmission operating expenditure is forecast to increase over time at a similar rate to other Australian transmission network business. The forecast operating expenditure for all transmission businesses except Powerlink[130] (Queensland) is based on recent decisions that have been made by the relevant regulator.

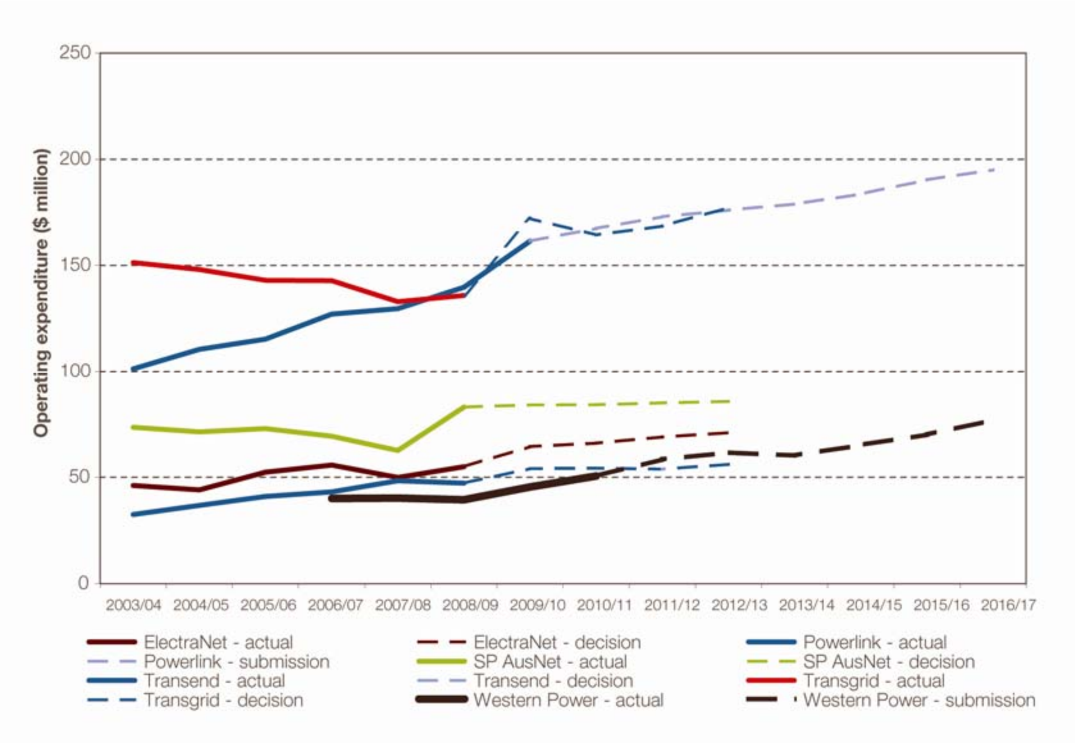


Figure 66: Comparison of forecast transmission operating expenditure against peers

Distribution operating expenditure

Our 2009/10 distribution operating expenditure is similar to the other Australian distribution network businesses on the basis of peak demand, line length and customer numbers. This is shown in Figure 67, Figure 68 and Figure 69 respectively.

Figure 67 illustrates that distribution operating expenditure as a function of peak demand is reasonably consistent across all distribution network businesses except one, which has a higher capital expenditure to peak demand ratio than the other businesses. This business has a large rural-based network.

Our distribution operating expenditure as a function of peak demand increases from 2009/10 to 2016/17 but remains similar to the other distribution network businesses.

[130] The forecast operating expenditure for Powerlink is based on its revenue submission to the AER for the 2012/13 to 2016/17 period.

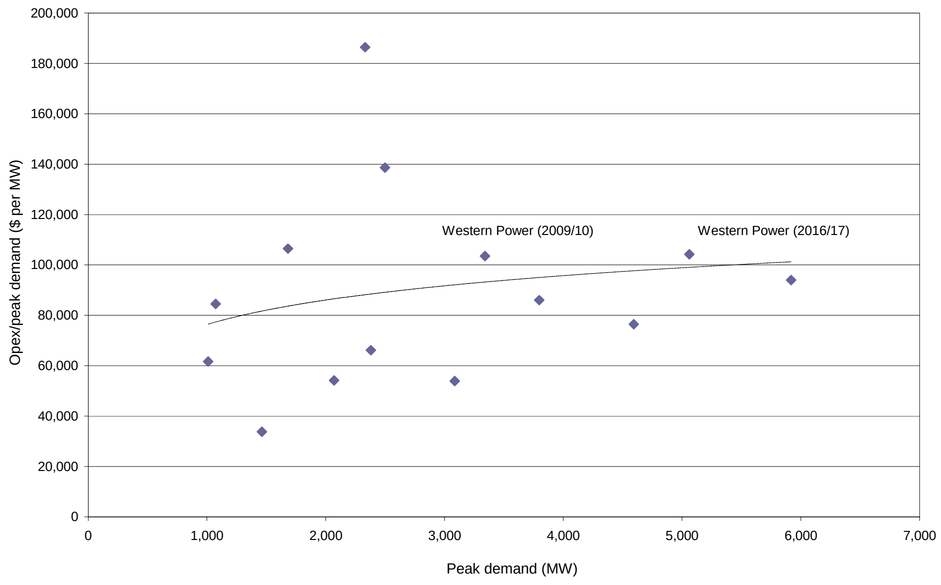


Figure 67: Comparison of distribution operating expenditure as a function of peak demand against peers, 2009/10

Figure 68 shows that the distribution operating expenditure as a function of line length decreases as line length increases.[131] Our distribution operating expenditure as a function of line length increases from 2009/10 to 2016/17 as the growth rate in line length during AA3 (1.2% per year) is low relative to the growth rate in operating expenditure (5.5% per year). The higher operating expenditure growth can be attributed to growth in labour costs averaging 2.7% per year, our network scale growth averaging 3.4% per year, and new non-recurrent costs such as for smart meters that we will incur during the AA3 period.

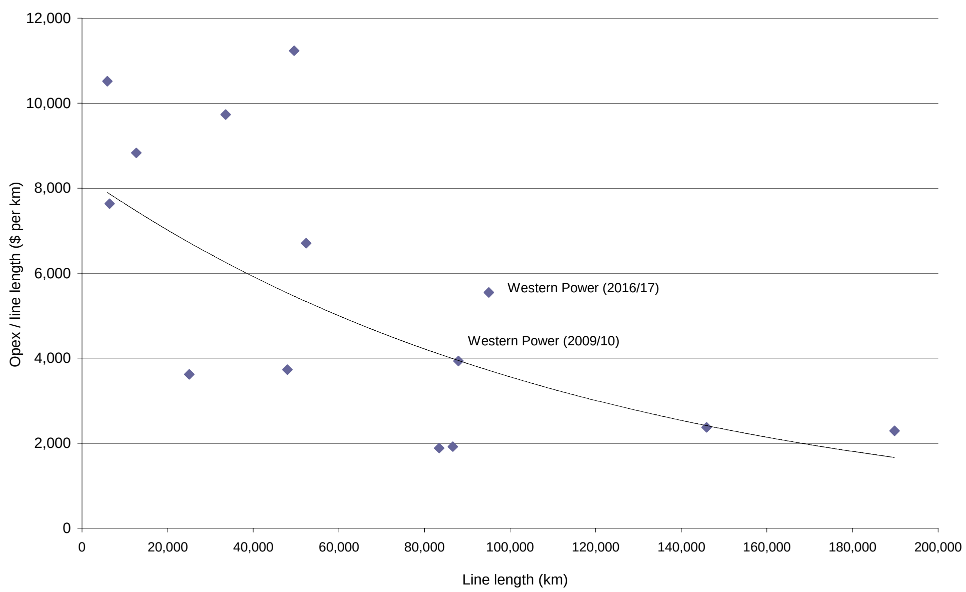


Figure 68: Comparison of distribution operating expenditure as a function of line length against peers, 2009/10

[131] Although the correlation between operating expenditure as a function of line length is not strong.

Figure 69 shows that our 2009/10 distribution operating expenditure as a function of customer numbers is in line with our peers. Most distribution network businesses fall between $200 and $500 per customer. Western Power's distribution operating expenditure as a function of customer number falls in the middle of this range in 2009/10, but increases to around $450 per customer in 2016/17. The increase in this ratio is because the only increase in operating expenditure from 2009/10 to 2016/17 that is attributable to customer growth relates to call centre and metering costs, which are much smaller than the remainder of our operating costs that are driven by the scale of the network. Our composite network scale growth is expected to outpace average customer growth by 1 percentage point per year during AA3.

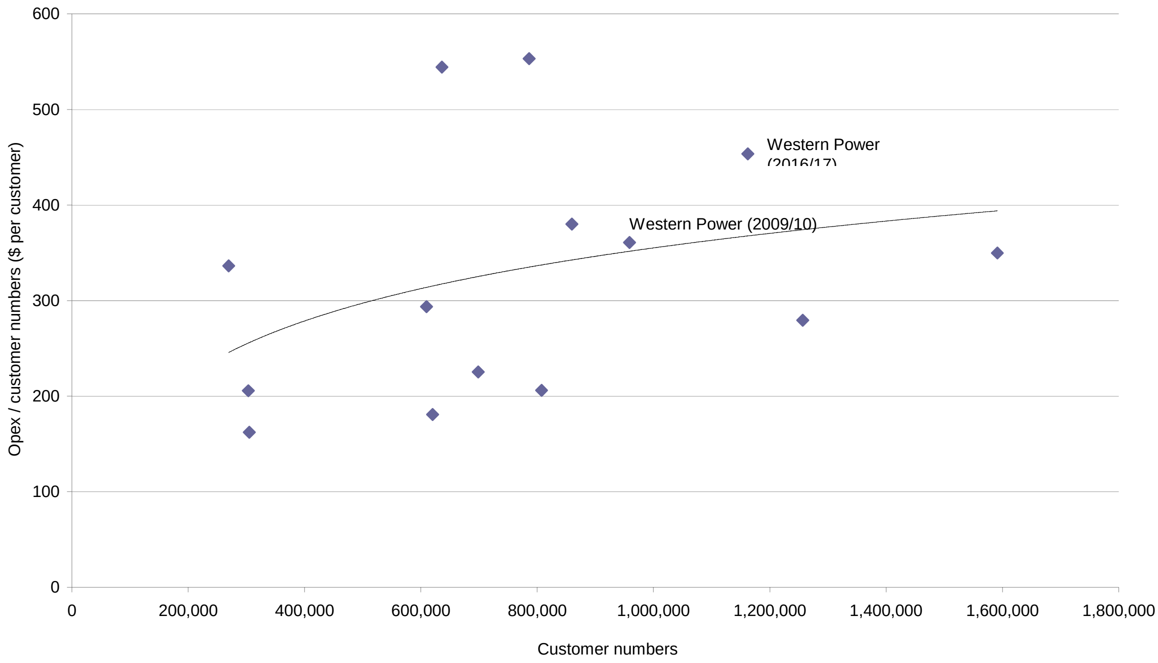


Figure 69: Comparison of distribution operating expenditure as a function of customer numbers against peers, 2009/10

Figure 70 and Figure 71 shows how our distribution operating expenditure is forecast to increase over time relative to peers. Figure 70 compares our forecast distribution operating expenditure against the distribution network businesses in Victoria, South Australia and Tasmania. Figure 71 compares our forecast distribution operating expenditure against the distribution network businesses in New South Wales and Queensland. The forecast operating expenditure for all distribution network businesses except Aurora[132] (Tasmania) is based on decisions that have been made by the relevant regulator.

As the distribution network businesses vary substantially in size, we have illustrated the forecast distribution operating expenditure relative to the operating expenditure in 2009/10, which is given a value of 100.

Figure 70 shows that our distribution operating expenditure is forecast to increase over the AA3 period at a slower rate than the distribution network businesses in Victoria, at a much slower rate than ETSA Utilities (South Australia), but at a faster rate than Aurora.

[132] The forecast operating expenditure for Aurora is based on a recent revenue submission to the AER.

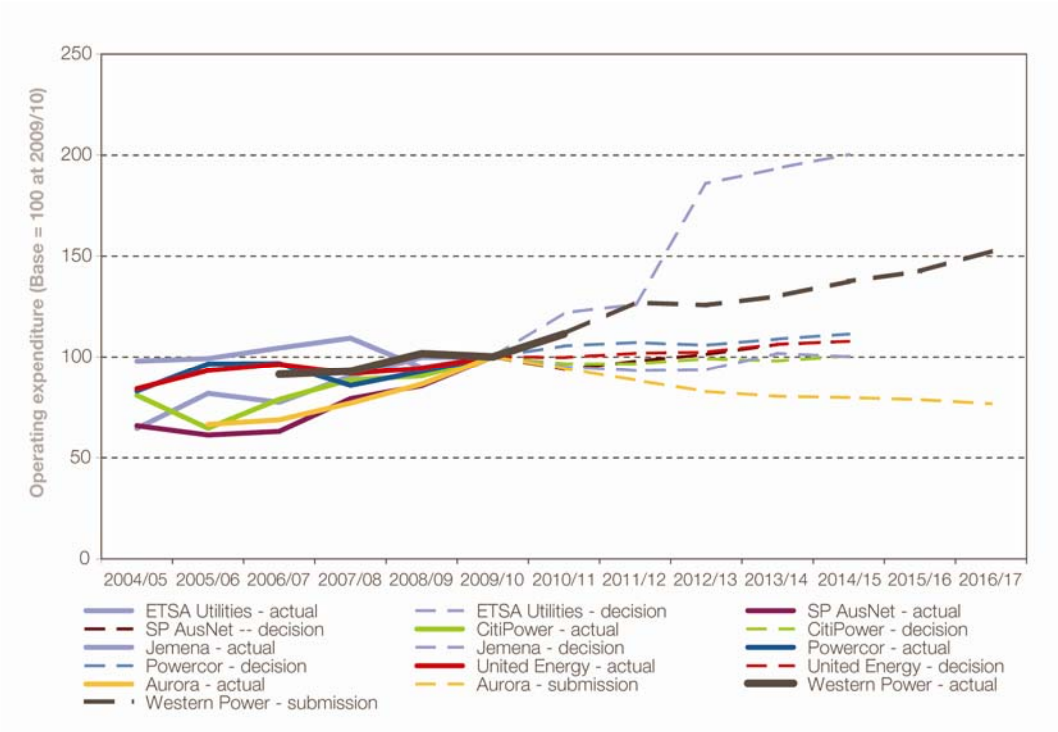


Figure 70: Comparison of forecast distribution operating expenditure against peers in Victoria, South Australia and Tasmania

Figure 71 shows that our distribution operating expenditure is forecast to increase over the AA3 period at a similar rate to the distribution network businesses in New South Wales and Queensland.

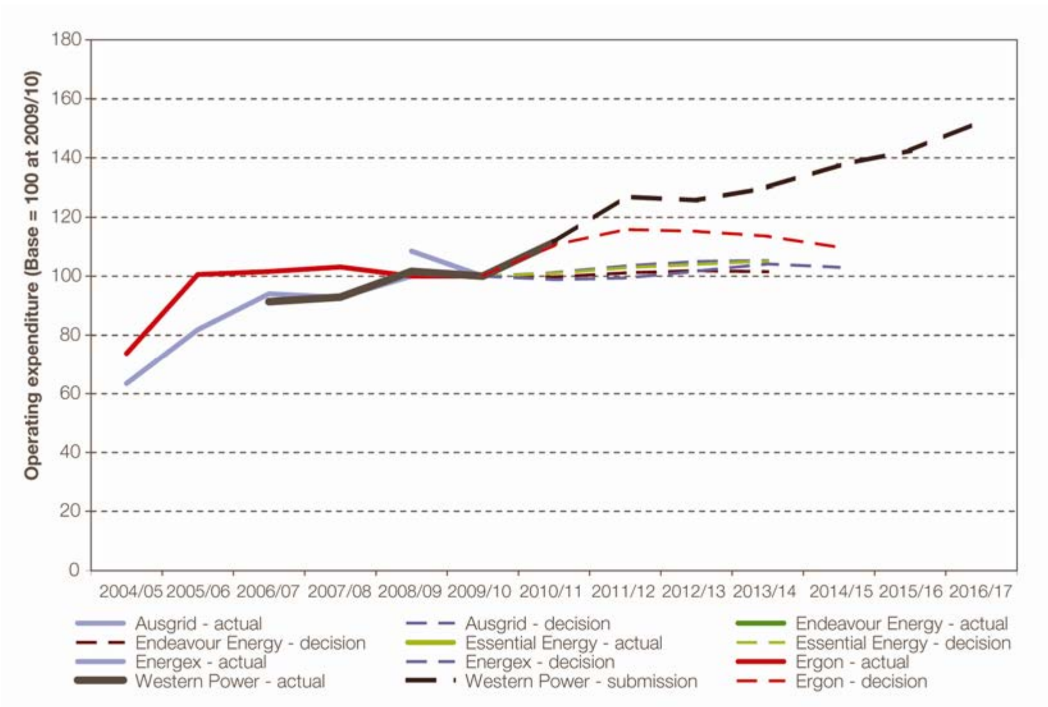


Figure 71: Comparison of Western Power's forecast distribution operating expenditure against peers in New South Wales and Queensland

Figure 68 and Figure 69 indicate that our distribution operating expenditure as a function of line length and customer numbers increases from 2009/10 to 2016/17 so that they are higher than our peers were in 2009/10. However, Figure 70 and Figure 71 indicate that we would continue to compare favourably with our peers if forecast 2016/17 data was used for the comparison rather than 2009/10 data.

7.10 AAI Guidelines provisions

Table 39 sets out where in this AAI and supporting appendices Western Power has provided information to demonstrate compliance with the AAI Guidelines requirements.

Table 39: Compliance with the AAI Guidelines

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.3.1	*Information supporting forecasts of costs must include:* • *the assumptions on which forecasts are based;* • *a full and detailed explanation of the basis of preparation of the forecasts; and* • *evidence to show the forecasts only include costs which would be incurred by a service provider efficiently minimising costs.*	Section 7.2
4.3.2	*The allocation of cost items must be based on the following principles.* • *Items that are directly attributable to a business component are allocated accordingly.* • *Items that are not directly attributable to a business component are to be allocated, where practicable, on a causation basis.* • *Items that are not directly attributable and cannot be practicably allocated on a causation basis must be allocated by a method determined by the service provider. In such cases, the access arrangement information must include a supporting note for each item thus allocated indicating:* – *the basis for allocation;* – *the reason for choosing that basis; and* – *an explanation for why no causal relationship could be established.* • *Consistency with previous years' allocation policies or, if not, any change to the allocation policy must be fully explained and prior year figures restated accordingly.*	Section 7.2 and Appendix E: Cost and revenue allocation methodology 2010/11
4.4.3	*Forecasts of non-capital expenditure must be accompanied by, at least:* • *details of the methods used to develop the forecasts*	Section 7.2
4.4.3	• *the forecasts of parameters relied upon to derive the forecasts and details of the methods and assumptions used to develop the forecasts of non-capital expenditure from these parameters*	Section 7.2

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.4.3	• *a description of asset maintenance plans relied upon to derive the forecasts of operating expenditure for the purposes of maintaining service levels, and details of the methods and assumptions used to develop the forecasts of non-capital expenditure in accordance with the asset maintenance plans*	Section 4.4 and Appendix L: Network Management Plan
4.4.3	• *a description of any regulatory obligations in service standards that have given rise to forecast non-capital expenditure and details of the methods and assumptions used to develop the forecasts of operating expenditure from the regulatory obligations*	Section 7.2 and chapter 5
4.4.3	• *a description of any consideration of consumer preferences that have given rise to forecast non-capital expenditure and details of the methods and assumptions used to develop the forecasts of non-capital expenditure from considerations of consumer preferences*	Section 5.5, 7.2 and Appendix Y: KPMG Report – Customer preferences for supply reliability survey
4.4.3	• *quantification of amounts relating to any projected changes in input prices and support for those assumptions*	Section 7.2.5
4.4.3	• *quantification and an explanation of material variations in the forecast of non-capital expenditure from historic levels of, and trends in, amounts of non-capital expenditure*	Section 7.8
4.4.3	• *non recurrent costs must be separately identified*	Section 7.2.2
4.4.3	• *evidence to show that the forecast costs only include those which would be incurred by a service provider efficiently minimising costs as required in sections 6.40 and 6.41 of the Access Code.*	Section 7.2
4.4.4	*A proposal for target revenue must contain identification and explanation of any significant interactions between the service provider's forecast capital expenditure and forecast non-capital expenditure.*	Section 7.7

8 Capital investment

This chapter provides an overview of:

- the forecast new facilities investment over the 2012/13 to 2016/17 regulatory period
- the activities, key drivers and the detailed forecasts for new facilities investment related to the key transmission, distribution and corporate regulatory cost categories
- the methodology used to develop the forecasts and how they comply with the relevant sections of the Access Code including sections 2.8(e) and 6.49 to 6.55 of the Access Code

Our new facilities investment comprises capital investment on the transmission and distribution networks. It also includes corporate capital investment, which supports the operation of the business through IT systems and business support functions such as corporate real estate, plant and equipment. These investments are hereafter collectively referred to as ‘capital investment’ or capital expenditure’.

Further information on activities, costs and reasons for variations by regulatory cost category for capital expenditure is provided in Appendix A: AA3 capital and operating expenditure report.

8.1 Key messages

- During AA3 we will invest $5.810 billion of capital to deliver key outcomes related to:
  - **safety** – addressing the highest priority public safety risks
  - **growth and security** – expanding the network’s capacity to meet growth and connect new customers, and improve system security to increase network resilience and reduce the risk of long-duration widespread outages
  - **service** – maintaining service at the historical average, with further improvements only where customers value them and it is economically efficient to do so
- Our capital works program is an economically efficient and deliverable program of work that is required to ensure that we can continue to provide covered services to new and existing customers while addressing network risks
- Our capital investment is driven by our long-term planning, asset management and works delivery system, which consider our regulatory obligations
- Our forecasts have been developed by regulatory cost category on the basis of three distinct cost estimation methods and take into account:
  - forecast movements in the market prices of labour and materials
  - our assessment of economies of scale or scope and the lowest sustainable cost of providing covered services and
  - outcomes including incremental revenue, net benefits and the continued provision of covered services including safety and reliability
- Our forecasts are comparable to other Australian transmission and distribution businesses operating when assessed against various metrics

Access Code provisions

Western Power's operating expenditure for the AA3 period is required to comply with sections 6.49 to 6.50 and section 2.8(e) of the Access Code.

Section 6.49

Subject to section 6.50, the capital base for a covered network must not include any amount in respect of forecast new facilities investment

.**Section 6.50**

For the start of each access arrangement period, the capital base for a covered network may include forecast new facilities investment which:

a) has not yet occurred but is forecast to occur before the access arrangement start date; and

b) at the time of inclusion is reasonably expected to satisfy the test in section 6.51A when made.

Section 6.51

For the purposes of section 6.4(a)(i) and subject to section 6.49, the forward-looking and efficient costs of providing covered services may include costs in relation to forecast new facilities investment for the access arrangement period which at the time of inclusion is reasonably expected to satisfy the test in section 6.51A when the forecast new facilities investment is forecast to be made.

Section 6.51A

New facilities investment may be added to the capital base if:

a) it satisfies the new facilities investment test; or

b) the Authority otherwise approves it being adding to the capital base if:

i. it has been, or is expected to be, the subject of a contribution; and

ii. it meets the requirements of section 6.52(a); and

iii. the access arrangement contains a mechanism designed to ensure that there is no double recovery of costs as a result of the addition.

Section 2.8(e)

Without limiting section 2.7, a service provider must:…

…when forming a view as to whether all or part of any proposed new facilities investment meets the test in section 6.51A, form that view as a reasonable and prudent person.

Section 6.52

New facilities investment satisfies the new facilities investment test if:

a) the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard, without limitation, to:

i. whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and

ii. whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a new facility with capacity sufficient to meet the forecast sales;

and

b) one or more of the following conditions is satisfied:

i. either:

A. the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or

B. if a modified test has been approved under section 6.53 and the new facilities investment is below the test application threshold – the modified test is satisfied;

or

ii. the new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs; or

iii. the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

8.2 Overview of the investment proposal

During AA3, we will invest $5.810 billion in capital to deliver covered services. Of this, approximately $958 million will be recovered directly from customers in the form of either customer contributions or gifted assets.

We forecast that $4.830 billion will be added to our capital base and funded through reference tariffs. This excludes the amount that we expect to receive in capital contributions and gifted assets which accounts for 16% of works.

Table 40 summarises our capital investment on the transmission and distribution networks and corporate support. It also shows the amount that customers will pay directly through contributions.

Table 40: Transmission and distribution capital expenditure by year by regulatory category

$ million real at 30 June 2012	2012/ 13	2013/ 14	2014/ 15	2015/ 16	2016/ 17	Total AA3	% of gross capital
Transmission capital expenditure	350.2	269.7	363.9	526.9	416.7	1,927.3	33.2%
Distribution capital expenditure	662.3	726.7	745.3	719.4	727.4	3,581.1	61.6%
Corporate capital expenditure	76.5	74.2	49.5	52.1	49.1	301.4	5.2%
Total capital expenditure	**1088.9**	**1070.7**	**1158.7**	**1298.4**	**1193.1**	**5809.8**	**100%**
Less capital contributions	207.9	193.4	182.8	184.6	188.8	957.6	16.5%
AA3 capital expenditure to be recovered through reference tariffs	**881.0**	**877.3**	**975.8**	**1,113.8**	**1,004.3**	**4,852.2**	**83.5%**

The proposed investment is a significant increase compared to the preceding five year period. However, the proposed capital works program represents economically efficient investment that is necessary to improve the current network asset condition and to achieve services outcomes.

As the network has aged it has become less safe, reached the limits of its capacity and become vulnerable to deteriorating levels of reliability. In the AA3 period we are seeking to address the highest priority safety risks, keep pace with growth and maintain historical average levels of reliability. The following figure provides an overview of how our investment is allocated to key areas related to service outcomes:

- safety
- growth and security
- customer-driven investment and gifted assets
- service provision

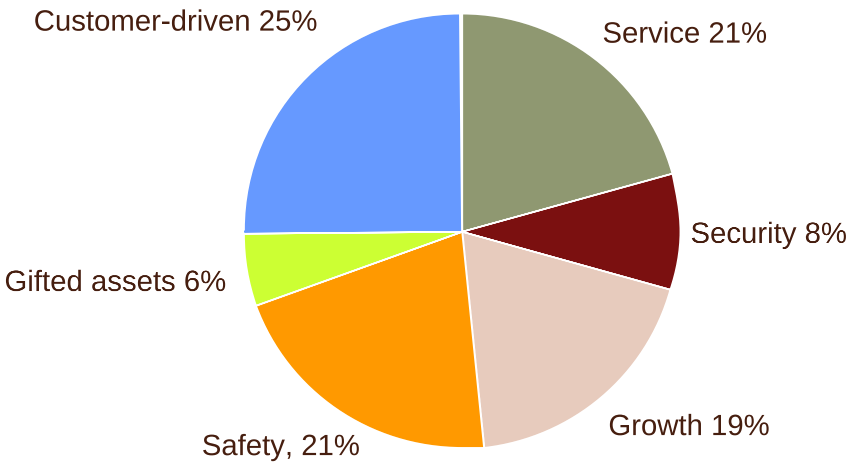


Figure 72: Percentage of capital expenditure by outcome

Over the past two access arrangement periods, customers have enjoyed steadily improving service as a result of targeted investment to improve reliability of supply and power quality. This has been achieved while connecting more than 47,763 new customers to the network. The vast majority of customers now enjoy a good level of service and will continue to do so throughout the AA3 period.

Much of the Western Power Network was constructed in the 1960s and 1970s. Safety and security have always been key drivers of investment. As the number of customers has increased, so too has pressure on the ageing network – and with it the underlying risk relating to safety, growth and security.

The continued growth in demand continues, and a further 130,000 customers are forecast to connect to the Western Power Network during AA3. Capacity expansion remains a key investment driver. However, AA3 represents a time when many of the network assets that were energised during the 1960s and 1970s are reaching the end of their serviceable lives, and many are in declining condition. This means that we need a sustained period of asset replacement to ensure the network remains safe and secure – while still facilitating growth – to prevent overall network condition from deteriorating to a level that it would be inefficient to recover from.

Our challenge is to address this network risk while efficiently minimising costs. We must also manage the price impact on customers that will result from the inevitable increase that is required to continue to deliver service. We have considered a range of options aimed at addressing our public safety, growth and security needs for the AA3 period. However, we assessed that alternatives would either result in risks rising to unacceptable levels, result in additional costs to customers that may not provide additional value or could not be delivered during the period. Ultimately we have chosen to maintain service levels at a standard consistent with that which customers presently experience rather than investing in further improvements, which would increase prices further.

The following sections provide a high level overview of the capital investment required to address safety risks, facilitate growth and restore security while preventing service from deteriorating. It also highlights the alternative options that we considered and why our proposed capital works program represents an appropriate balance between cost and outcomes.

A more detailed breakdown of capital investment for transmission, distribution and corporate capital expenditure by regulatory category is included in sections 8.4 to 8.7 of this document, with further detail in Appendix A: AA3 capital and operating expenditure report.

8.2.1 Investing in public safety

As with any electrical network, the Western Power Network carries an inherent safety risk and we need to invest appropriately to reduce this risk. During AA3 we will invest $1.222 billion of capital in four key public safety programs, which will decrease the potential for public safety incidents in the network. This is 21% of the total capital investment for AA3.

These programs relate to:

- bushfire mitigation
- pole management
- replacing obsolete overhead customer service connections
- conductor management

While safety performance is significantly influenced by external factors such as adverse weather, our aim is to manage the factors that are within our control such as ensuring our assets are in good condition.

These four key programs will have the greatest effect on reducing the likelihood of major public safety incidents and can feasibly be delivered during the period.

Delivering the safety investment program will improve the condition of our pole population and satisfy safety regulatory obligations. Most importantly, this investment will minimise further physical degradation of the network and aims to reduce the likelihood of electric shocks caused by assets as well as asset-initiated fires.

Our current plan is to increase our rate of wood pole replacement so that within 20 years we are treating poles at the same rate at which they are identified to require treatment. We will also replace conductors in extreme and high fire risk areas, eliminate long bays over a ten-year period and replace all high risk service connections over five years.

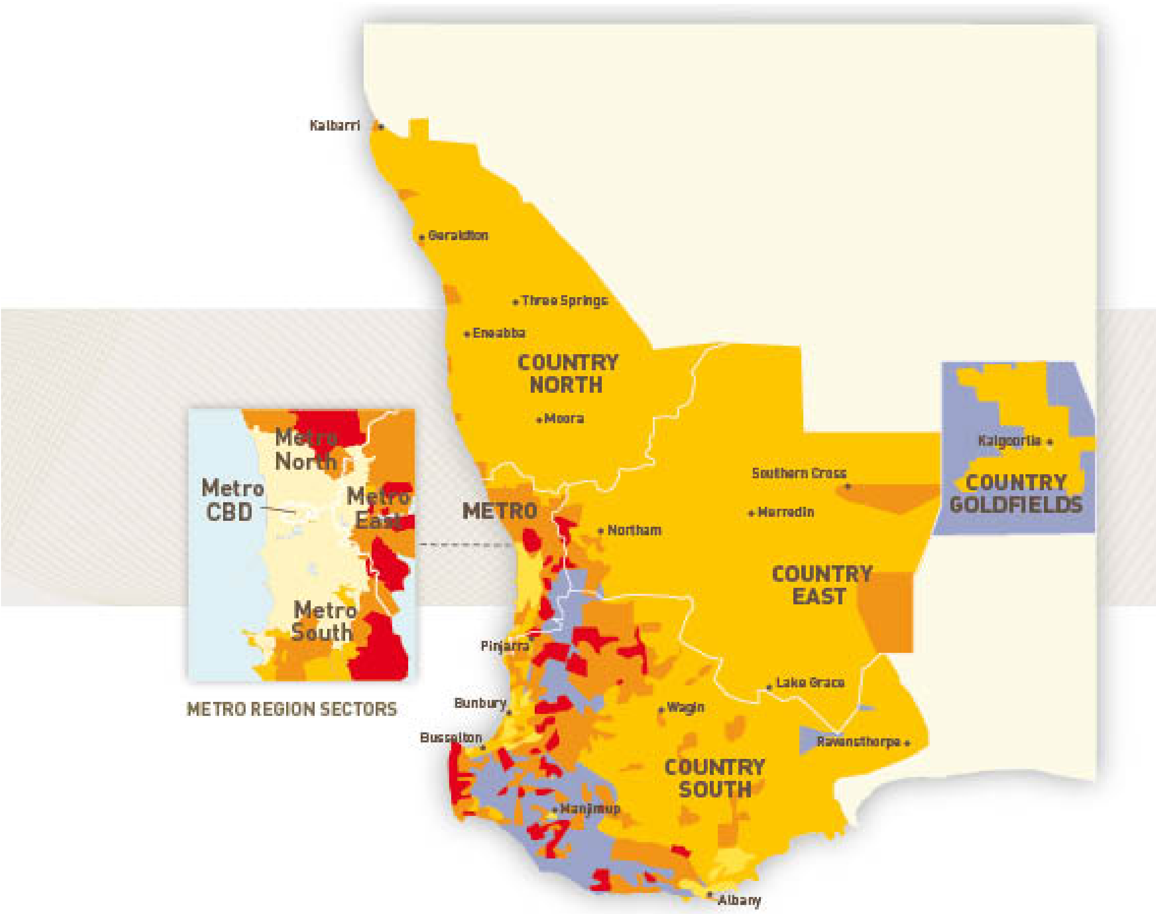
The following sections provide further detail about our proposed public safety works over the AA3 period.

Pole management and bushfire mitigation

The inherent risk of electricity providing a source of ignition, coupled with Western Australia’s hot, dry summer climate means that there is significant potential for bushfires, some of which may to be attributed to network assets.

There are 176,000 wood poles located in ‘extreme’ or ‘high’ bushfire risk areas. A failed wood pole presents multiple hazards – it can harm people or damage property. Energised power lines contacting the ground can also cause electric shock and, in very specific conditions, cause fires.

Figure 73 illustrates the fire risk zones across our network and the number of poles in each zone.



LEGEND

	FIRE RISK ZONE TYPE	NO. OF WOOD POLES
	Extreme	41,025 (7% of total)
	High	125,586 (20% of total)
	Medium	288,593 (46% of total)
	Low	173,747 (28% of total)
	No wood poles in this area	0

Figure 73: Number of wood poles by fire risk zone in the Western Power Network

Our objective is to replace or reinforce any unsafe pole before it falls. Wood poles are usually serviceable for 40 to 50 years. More than 200,000 of our 630,000 wood poles are over 40 years old. Our pole failure rate is the highest in Australia by a significant margin because of the overall condition of our poles.

We therefore propose to increase pole replacement and reinforcement rates during AA3. The plan is to replace or reinforce an average of 33,000 poles per year at a total cost of $748 million. This is a 40% increase on the AA2 program, which in turn was double the AA1 program. The program will be prioritised to address the poles in the poorest condition and in the highest risk locations first.

Based on the current assessment of the condition of the wood pole population, it will take 20 years of elevated investment before we achieve a position of replacing and reinforcing poles at the same rate that they are identified to require replacement or reinforcement – the sustainable rate. We anticipate the sustainable rate to be 20,000 poles per year. As shown in Figure 74, more aggressive investment profiles were considered. Achieving the sustainable rate of treatment[133] within 5 years would satisfy regulatory requirements more quickly, however it is practically undeliverable given available resources. A ten-year plan to achieve the sustainable rate of treatment was also considered, which while deliverable, would result in significantly higher costs than a longer program due to the significant uplift in materials and labour required.

Our 20-year wood pole management plan is the most achievable approach to improving the overall condition of the wood pole population in line with our regulatory obligations.

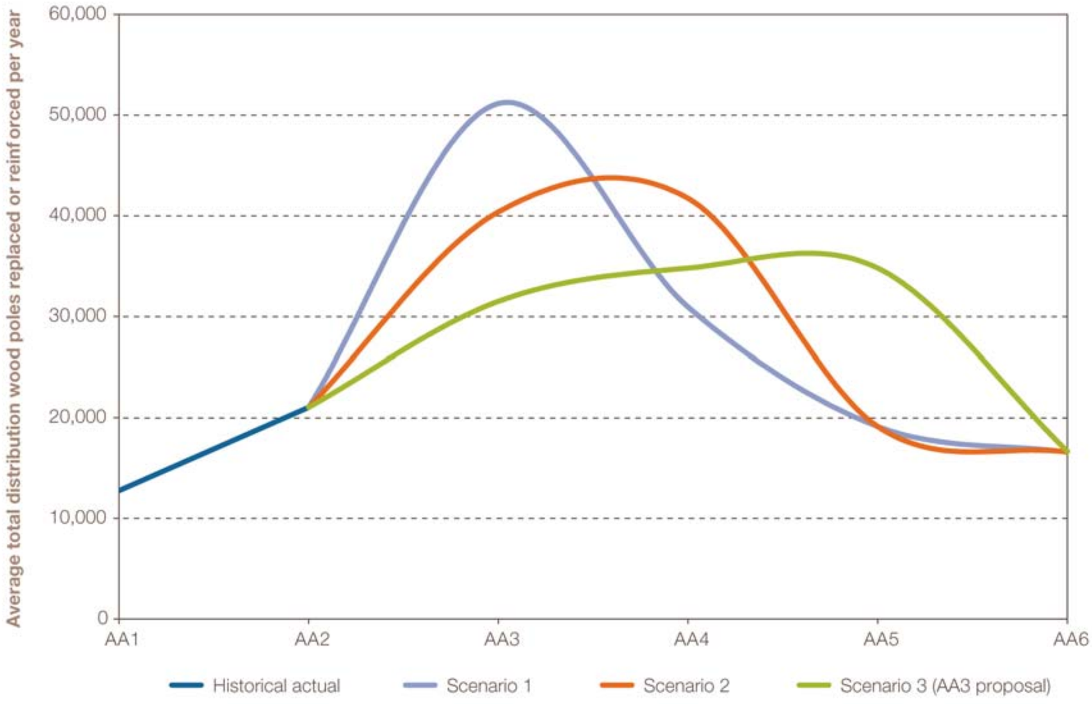


Figure 74: Comparison of paths to achieving a sustainable rate of wood pole replacement over 5, 10 or 20 years

133 Pole treatment may be either replacement or reinforcement.

We also propose an increase in other specific bushfire mitigation activities such as addressing long bays to reduce the risk of conductors clashing, vegetation management and pole top replacement. Our capital expenditure on bushfire mitigation will increase from $34 million per year in AA2 to $45 million per year in AA3.

Overhead customer service connections and conductor management

At the end of AA1 there were 272,000 obsolete overhead customer service connections in the Western Power Network. The connections link customers to the distribution network. Historically they have been responsible for an average of 80% of the total electric shocks attributed to our assets each year.

By the end of AA2 we will have replaced more than 100,000 of these potentially dangerous connections. We will replace the balance by the end of 2014/15. This average annual capital expenditure will be $17 million in AA3 compared to $25 million during AA2.

The network also contains 53,650 km of overhead power lines. All overhead electricity networks carry an inherent public safety risk due to the potential for conductors to fall or clash due to equipment failure, extreme weather or other external factors. During AA3 we will replace 1073 km of the power lines in the poorest condition to reduce this risk.

8.2.2 Growth and security of supply

Western Australia's economy is continuing to expand at a stable rate.[134] Electricity demand has risen, with peak demand increasing on average by 147 MW per year over the last decade. As discussed in section 6.2 of this document, we forecast that this rate of increase will continue throughout AA3.

Figure 75 shows the forecast increase in peak demand over the AA3 period.

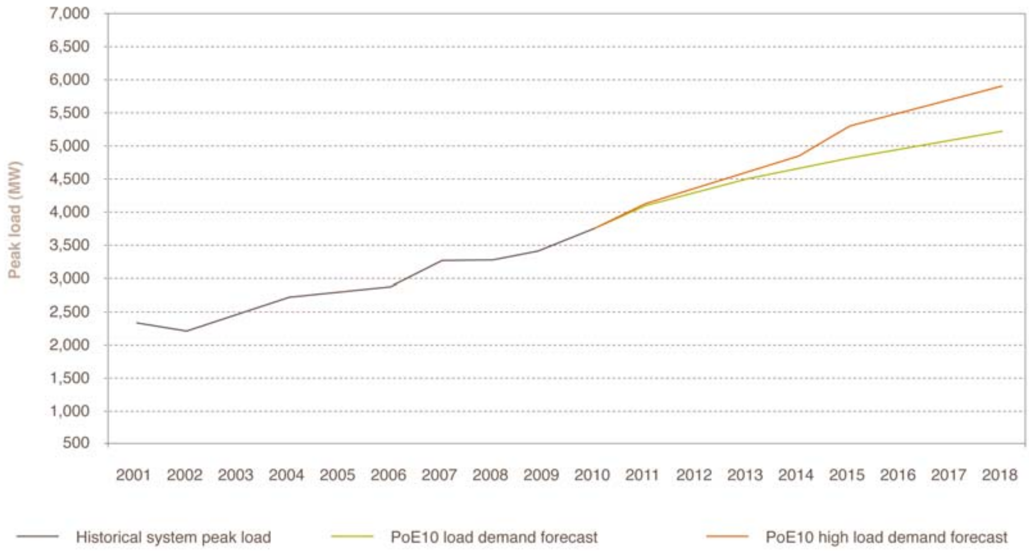


Figure 75: Forecast and historical increase in system peak demand

[134] p23, *'Economic Outlook', Budget 2011-2012 Budget Overview*, Government of Western Australia, May 2011.

We need to further invest in capacity expansion to accommodate the growth in peak demand while maintaining current network adequacy and security levels. The average cost of this is approximately $675 million per year.

As discussed in section 6.2, the growth in peak demand across the network provides an indication of the investment required in capacity expansion but it is not the driver of investment. It is the growth in peak demand at the zone substation level that drives investment in capacity expansion. Increased capacity is required in those areas of the network where the growth in demand would result in our technical obligations being breached if no action was taken. [135]

During AA1, we were able to keep pace with growth through a program of efficient capacity expansion. However, in AA2 the economic down-turn combined with an internal governance review prompted us to revisit and reprioritise our works program to ensure we could meet long-term growth. As a result, several capacity expansion projects were postponed and reserve network capacity was used to keep pace with the steady increase in electricity demand.

While this strategy enabled us to continue to connect customers to the network during AA2, by the end of the period there will be very little reserve capacity left to allow the network to continue functioning effectively in the wake of an outage event. This is not sustainable for AA3.

Our program for AA3 is based on the least-cost approach to meeting long term growth across the network, balanced against what can physically be delivered during the period given process approval constraints (for example environmental and regulatory approvals).

Forecast capital investment in growth and security is $3.374 billion, compared to $2.759 billion invested in the preceding five-year period.

While the increase in growth and security-related investment is substantial, the implications of not delivering this work during AA3 are significant. A lower level of investment may lead to restrictions on the number of customers that can connect to the network, potentially inhibiting economic growth. The worst-case scenario would be system collapse with a similar outcome to the five-hour blackout that occurred in 1994. It is estimated that an equivalent collapse would have a $350 million impact on the Western Australian community if it occurred today.

The combined effect of security and growth projects is to:

- meet a increased in system peak demand from 3639 MW in 2009/10 to 5061 MW by the end of AA3
- enable secure connection of an estimated 130,000 new customers
- reduce the number of metropolitan customers at risk of long duration outages (longer than 5 hrs) due to insufficient distribution transfer capacity by 420,000 by the end of AA3
- return the number of customers at risk of supply interruptions due to single outages of transmission infrastructure to 100,000 by the end of AA3
- reduce the number of metropolitan distribution feeders that are loaded above 80% [136] from 236 to 0 by the end of AA3, thereby significantly reducing the number of customers at risk from prolonged outages

[135] For example, high demand growth in an area with reserve capacity will not require investment in capacity expansion, however even low demand growth will drive capacity expansion if it occurs in an area of the network that is currently has constrained capacity.

[136] The level of interconnection of distribution feeders in the Perth Metropolitan area allows a target utilisation of 80% which is higher than the national benchmark level of 66%.

- reduce the number of country customers at risk of potential equipment damage due to being supplied from voltage constrained country feeders by 70% by the end of AA3
- enable secure connection of proposed new large generators in the mid-west, which is not currently possible

Facilitating growth

Capacity expansion is a key driver of the forecast increase in capital investment. Although the investment required is driven at the substation level, Figure 76 shows the variation in growth in capacity required by region by the end of the AA3 period.

LEGEND

- 15-20 % decrease
- 10-15 % decrease
- 5-10 % decrease
- 0-5 % decrease
- 0-5 % increase
- 5-10 % increase
- 10-15 % increase
- 15-20 % increase

REGION	FORECAST 2012 PEAK DEMAND (MW)	FORECAST 2017 PEAK DEMAND (MW)
Metro CBD	394	441
Metro North	1186	1409
Metro South	1461	1763
Metro East	208	230
Country North	268	312
Country South	484	553
Country East	226	231
Country Goldfields	105	122
TOTAL	4332	5061

Figure 76: Forecast increase in peak demand by region by 2017

The majority of growth-related investment in AA3 is driven by customer connections. Customer-driven work to respond to the needs of residential, commercial, industrial and generating customers is forecast to increase, resulting in 130,000 new loads by the end of the AA3 period.

This customer-driven investment accounts for $1.782 billion (53%) of growth-related capital expenditure during the period, of which 79% relates to works for our distribution-connected customers and the remaining 21% for our transmission-connected customers. Of this investment, we anticipate $914 million[137]will be covered by direct contributions from customers. The effect of these contributions is that it reduces the amount of investment added to the capital base compared to the investment undertaken. This means the customers that require this work pay for it and the reference tariff to all other customers is not affected.

Customer-driven transmission works are subject to fluctuations in customer needs and timeframes. During AA2, the global financial crisis caused the number of new transmission applications to drop below AA1 levels in 2009/10, before picking up in 2010/11. We now have a record number of major load and generator connection applications. In the case of significant differences in actual growth-related investment compared to forecast, the arrangements we had in place during AA2 to ensure customers pay only for growth investment that actually occurs will continue into AA3. This will be managed through the investment adjustment mechanism.

It is important to recognise that customer-driven work is non-discretionary as a result of our obligation to connect under the *Electricity Industry (Obligation to Connect) Regulations 2005*[138] and the requirement for electricity generators to have unconstrained generation dispatch.

Improving network security and reducing system overloads

System security is achieved by building a level of reserve capacity into the system to allow it to continually supply customers in the event of an unplanned outage.

As previously described, deferral of investment in capacity expansion during the AA2 period led to much of the reserve capacity in the network being used up by the connection of new customers and load growth. In AA3 we will ensure network security by building sufficient reserve capacity back into the network. The investment in this program is $489 million or 8% of investment.

The Australian benchmark for maximum individual distribution feeder utilisation is 66%. This was re-confirmed[139] following a catastrophic event in Queensland in 2004 which resulted in widespread outages, and significant economic loss. A root cause was identified as overly aggressive distribution utilisation (76%).

There are currently 420,000 customers connected to our distribution network supplied by feeders at greater than 80% utilisation which are at risk of long-duration[140] outages due to feeder failure. The proposed investment will significantly reduce this risk by the end of AA3. Figure 77 provides an indication of feeder utilisation in the metropolitan area.

[137] 77% from distribution-connected customers and 23% from transmission-connected customers.
[138] See Section 4 *'Obligation to attach or connect premises'*, *Electricity Industry (Obligation to Connect) Regulations 2005.*
[139] *Report on Electricity Distribution and Service Delivery for the 21st Century* (Somerville Report), 2004.
[140] Longer than 5 hours.

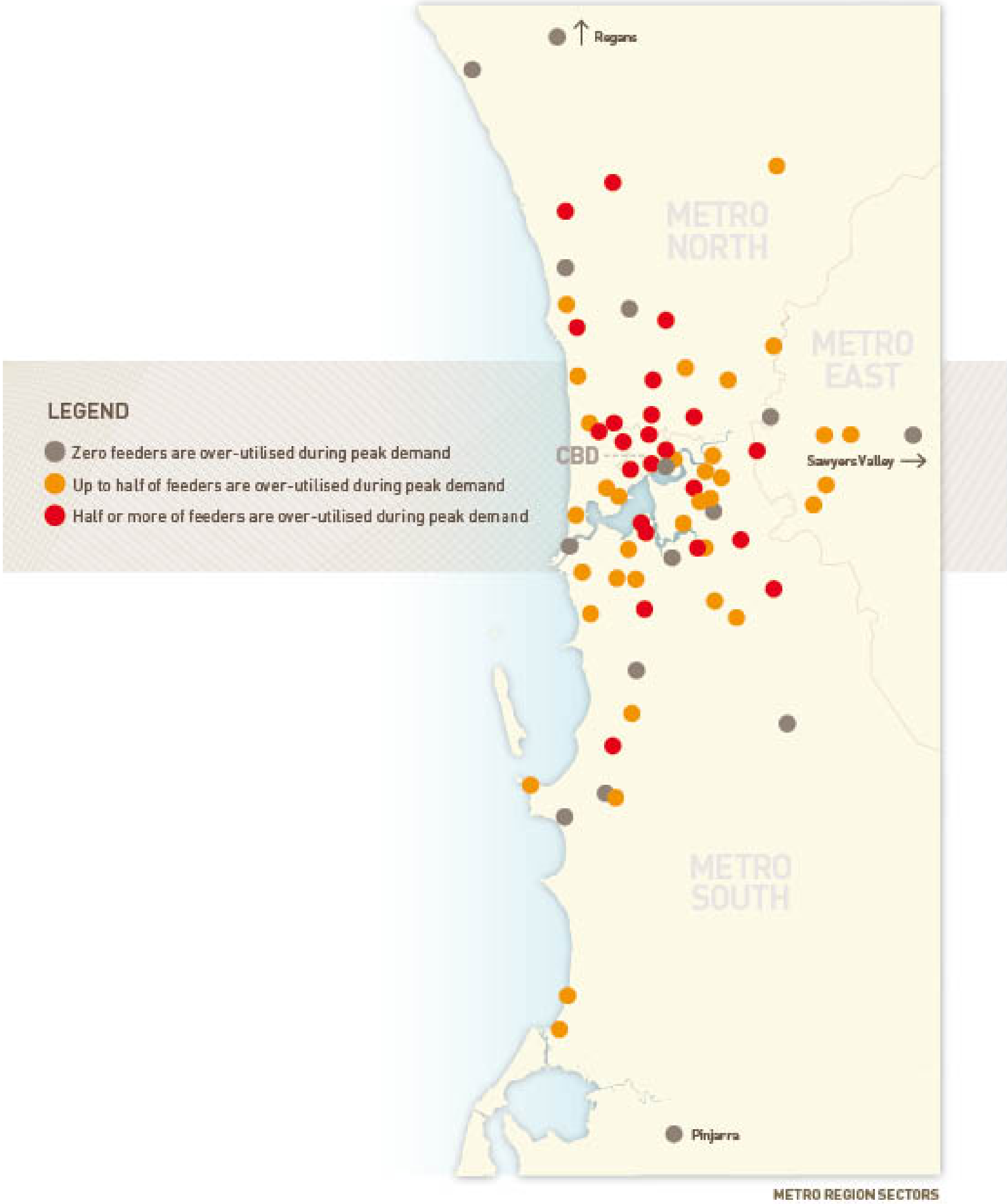


Figure 77: Feeder utilisation in the Perth metropolitan area

8.2.3 Maintaining service levels

In AA3, our focus is to maintain average historical service levels throughout the period.

This includes maintaining compliance with a number of statutes that cover all aspects of planning, developing and managing the electricity network. As new and improved standards are implemented, failure to upgrade the network will result in Western Power becoming non-compliant with regulations to ensure public safety or maintain service quality.

Failure to invest in these programs will:

- increase our legal and operational liability for non-compliance with various legislative requirements
- lead to an increase in public and operator safety risks
- lead to an increasing gap between our practices and recognised prudent asset management practices
- progressively reduce reliability
- progressively increase operating expenditure, which is an inefficient use of resources

The proposed capital investment on maintaining service levels and compliance is $1.214 billion. This represents 21% of the AA3 capital investment proposal. It is focused on replacing unserviceable transmission and distribution assets in addition to the pole replacement program and includes replacing 280,000 non-compliant three-phase electricity meters to ensure we comply with legal obligations under the *Metering Code*.[141]

In some cases, there is a risk that additional investment will be required. For example, ongoing discussions with the Environmental Protection Agency indicate that an additional $270 million of expenditure may be required if we are obligated to comply with new noise regulations relating to distribution assets.

It is important to note that while we are proposing to maintain service and compliance levels for AA3, the cost of achieving this will be greater than in AA2. This is due to asset age, declining asset condition and loading.

The decision to maintain current service levels rather than further invest in improving service is based on:

- a series of customer engagements and survey of customer preferences[142] conducted in October 2010 which provided evidence that the majority of our customers are satisfied with current average service levels[143]
- the service standard incentive framework is considered to be sufficient to ensure investment to maintain and improve service where it is valued more than the cost of delivering. This is preferable to including additional investment for service improvements that would further increase prices.

Delivering improvements in rural and edge-of-grid areas costs significantly more per capita than in metropolitan areas and is often financially prohibitive. However, our proposed

[141] *Electricity Industry Metering Code 2005*.
[142] The KPMG survey engaged more than 600 residents and small businesses to determine their preferred level of reliability.
[143] Customers in rural areas, where reliability performance is often poorer than metropolitan areas, were an exception to this rule and indicated they would prefer service improvements. However the cost of delivering improvements in rural areas is difficult to justify under the current regulatory arrangement.

changes to the incentive regime will provide an increased incentive to deliver improvements in rural and edge-of-grid areas where it is efficient to do so.

We believe our approach to maintaining average service levels and investing in improvement only where it is economically efficient is fairer to all customers.

8.2.4 Regulatory categories of investment

The discussion in this chapter has considered the capital investment required in AA3 under three themes or areas of investment:

- safety
- growth and security
- service

However, the AAI Guidelines specify regulatory categories that are to be used in the regulatory financial statements. The following sections consider the investment requirements and forecasts by these regulatory categories.

Table 41 shows the regulatory categories that make up each area of investment.

Table 41: Capital expenditure regulatory categories that incorporate the proposed areas of investment

Investment area	Associated regulatory category
Safety – four priority programs ($1.222 billion)	Transmission – compliance Distribution – asset replacement Distribution – compliance
Growth and security ($3.374 billion)	Transmission – capacity expansion Transmission – customer-driven Distribution – capacity expansion Distribution – customer access Distribution – gifted assets
Service maintenance and compliance ($1.214 billion)	Transmission – asset replacement Transmission – compliance Transmission – SCADA and Communications Distribution – asset replacement Distribution – compliance Distribution – SCADA and communications Distribution – reliability driven Metering Smart grid SUPP Corporate Support

8.3 Forecasting methodology

This section describes the methodology and approach that we have used to forecast our capital investment requirements for the AA3 period.

We have used a two stage process to determine our AA3 forecast capital investment:

1. **determine the works required to be undertaken in the period**
2. **estimate the cost of the required works**

The two stages are discussed in the following sections.

8.3.1 Determining the AA3 capital works program

To determine the required work to be undertaken over the 5 years, we have relied heavily on our asset management system and historical out turn information. Our growth related investment requirements rely heavily on our forecasts of load growth and new customers which are fed into our network planning tools. For customer-driven growth investment we have adopted the historical investment trends for the most part to avoid having to estimate particular customer requirements. Non-growth investment requirements follow our asset management plans and understanding the current and future costs of complying with our many technical requirements and legal obligations.

The following sections provide an overview of how we have determined our investment requirements for our growth, non-growth and corporate investments.

8.3.1.1 Growth driven capital works

Our growth capital investment program is driven by:

- **customer-driven growth investment** – customer requests for new connections, expansions or modifications to existing connections, and relocation of network assets
- **gifted assets –** assets built by customers are then transferred to Western Power to own and operate
- **capacity expansion** – growth in the peak summer demand (organic load growth) and generation planting scenarios

This investment category remains subject to the investment adjustment mechanism (IAM) for the AA3 period. This mechanism ensures that customers pay only for the investment in growth that actually occurs. Any variation between forecast and actual growth related capital expenditure will be adjusted, meaning that if the actual growth-related investment is less than forecast, the associated revenue is returned to customers under the IAM in the next access arrangement period.

Customer-driven growth investment

The investment program forecast for AA3 customer-driven works reflects historical levels of capital expenditure.

Transmission customer-driven works relate to customer connection applications. The transmission customer-driven works program typically reflects a small number of large projects. For example, in 2010/11 approximately 60% of transmission customer-driven work was attributed to two projects: the Binningup desalination plant and the Collgar wind farm.

We track connection applications to monitor future requirements. Experience shows that not all applications proceed to final connection requests and some may be delayed or modified at the customers' discretion. As a result, there is a high level of uncertainty as to the timing and costs associated with specific projects.

If all the existing transmission access applications went ahead we would incur capital expenditure in excess of $1 billion during AA3 in this category. This is well over the historical expenditure of approximately $60 million per annum. We therefore have forecast AA3 investment on the basis of historical average expenditure given the uncertainty about which access applications are likely to go ahead.

Distribution customer-driven works include work related to new or modified connections for customers connected to the distribution network, network expansion, subdivisions and asset relocations. The works distribution program typically reflects a large number of small projects. These projects are largely completed within a six-to-twelve month period and individual activities are difficult to forecast with accuracy over five years.

However, the level of expenditure in this category is reasonably stable. We consider that the Access Code requirements are best satisfied if forecast investment in distribution customer-driven works reflects historical expenditure, adjusted for expected growth in new connections and other identifiable drivers. This ensures that prices are not increased above levels that have been sufficient to meet customer's needs in the past. The investment adjustment mechanism also ensures that we are able to invest efficiently in customer-driven capital expenditure if necessary.[144]

Gifted assets have been forecast based on the historical volumes and considering land development and lot clearing projections from other utilities and Government planning agencies. The gifted assets contribution is based on an internal estimate of the 'fair value' of the construction cost, rather than on the actual cost incurred by the third party. The impact of gifted assets on customers is the requirement to pay tax on these assets.[145]

Capacity expansion

The required capital expenditure program for capacity expansion in AA3 has been identified through the Transmission Network Development Plan (attached at Appendix O). It includes projects necessary to ensure there is sufficient network capacity to transfer electricity to customers and to meet the Technical Rules considering forecast load growth and new connections. It also identifies the lowest cost combination of projects to meet forecast load scenarios over a ten-year planning period.

We use detailed system studies to forecast capacity shortages or network issues as the load grows and new generators connect to the network. System studies undertaken for the AA3 period cover a variety of load and generation scenarios to ensure that each network element (configuration of assets) satisfies technical criteria so that:

- each individual asset is operated within its design limits
- each network element can operate within its design limits and the network can perform as required when unplanned outages occur
- the quality of supply is maintained to the appropriate standards
- future growth is efficiently provided for
- environmental impacts are responsibly managed in order to ensure the network is maintained and expanded in a sustainable manner

The forecast works program considers how we will most cost effectively achieve the capacity expansion required to satisfy the technical criteria. We investigate the costs and benefits of

[144] Section 2.19(a), *Electricity Networks Access Code 2004.*
[145] Chapter 9 discusses the recovery of these tax costs through our revenue requirement.

both network and non-network options as part of developing the portfolio of works to address the identified network issues. This ensures we determine the optimum projects to address forecast breaches of the technical criteria at the lowest sustainable cost.[146] In AA3 we will continue to use non-network alternatives where appropriate in the form of network control services in both the transmission and distribution network. This is discussed in more detail in Appendix A: AA3 capital and operating expenditure report.

8.3.1.2 Non-growth capital works

The AA3 capital investment program for non-growth works is forecast based on the asset requirements outlined in our Network Management Plan (attached at Appendix L). In most cases, the works are the result of detailed individual asset strategies, identified public safety issues or to introduce new or innovative technology.[147]

Our strategy is to maintain network performance within acceptable risk levels while efficiently minimising costs. This is articulated in our network management plan. We achieve this by balancing a mix of proactive and reactive asset strategies using capital and operating solutions, as defined by the asset's criticality to the performance of the network in terms of reliability, safety, environmental impact and economic consequences.

Our asset management approach reflects the type of asset and the associated risks and consequences of asset failure. The investment trigger is based on an assessment of the criticality of network assets, in conjunction with asset age profiles and condition profiles. Replacement strategies are also guided by cost and risk assessments when setting a run-to-failure or non-run to failure (replace on condition) strategy. This analysis informs the forecasts of future asset replacement requirements, which are documented by asset class in the network management plan. This is good electricity industry practice.

> Good electricity industry practice is defined in the Access Code as:
>
> *The exercise of that degree of skill, diligence, prudence and foresight that a skilled and experienced person would reasonably and ordinarily exercise under comparable conditions and circumstances consistent with applicable written laws and statutory instruments and applicable recognised codes, standards and guidelines.*

Assets that have a significant impact on reliability, safety or the environmental or economic aspects of the business are replaced on condition (non-run to failure). All other assets are classified as run-to-failure assets as they have a minimal impact on overall network performance. This balancing of works planning methods allows us to maintain the safety and reliability of the covered network[148] while efficiently minimising costs.[149]

We have also included a small proportion of our investment is dedicated to investigating and piloting new technologies to enable future cost effective and efficient solutions to network issues or to align to changes in industry practice. Building on our AA2 smart grid foundation program, we are leveraging our requirements to replace 280,000 non-compliant three-phase meters with smart meters and a further 52,000 new and replacement smart three-phase meters per year with the supporting communications required to realise the benefits of those meters.[150]

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[146] Section 6.52(a)(ii), *Electricity Networks Access Code 2004.*
[147] These include, for example, individual strategies related to bushfire mitigation, smart grid and some SCADA and Communications projects.
[148] Section 6.52(b)(iii), *Electricity Networks Access Code 2004*.
[149] Section 6.52(a), *Electricity Networks Access Code 2004*.
[150] We are substituting new and replacement three-phase meters for smart meters. These customers have on average 63% higher electricity consumption than customers with single-phase meters.

8.3.1.3 Corporate capital works

Our corporate capital works program is required to support Western Power's business. The majority of our AA3 program reflects key projects commenced in AA2. These include:

- purchasing property
- purchasing plant and equipment
- refurbishing head office and major depots
- replacing end-of-life IT hardware and software
- delivering the enterprise systems transformation initiative[151]

The AA3 corporate capital works program has been developed and prioritised by the operational areas responsible for delivering corporate services. There are two new major corporate programs identified for AA3: investment in new IT technology and the development and maintenance of metering management systems. The need for these works has been identified through the enterprise systems asset management plan, which is set out in Appendix N.

We have adopted a fit-for-purpose approach to determining the forecasts for corporate capital works. This has involved forecasting:

- recurrent corporate capital investment required to maintain the safety and reliability of the covered network[152]. This includes investing to improve or maintain compliance to the *Building Codes of Australia, Operational Health and Safety Act 1984* (including *NOHSC 2005 Code of Practice for Asbestos Removal*) and the *Environmental Protection Act 1986* for a safe working environment
- recurrent corporate IT capital requirements required to maintain the safety and reliability of the covered network[153]. This includes continuing our historical expenditure, accounting for increases in user demand, the expected useful life of our IT infrastructure and anticipated economies of scale from a greater number of users
- other non recurrent strategic initiatives to deliver a net benefit[154]. This includes the enterprise systems transformation initiatives and identifying further IT system initiatives that will improve staff productivity and develop more efficient processes to streamline the execution of work. Costs are forecast based on historical upgrades of similar scope and size

8.3.2 Optimisation of network capital projects

We have applied a number of tools to test for overlaps and dependencies in identified work programs and to efficiently package or schedule the works. These enable us to realise economies of scale and efficiently minimise costs. These tools include the:

- **smart planning tool** – provides transparency of transmission works by individual primary asset or substation location to minimise transmission network outages and consolidate maintenance, growth and non-growth capital works
- **overlaps and dependencies model** – maps required work by asset class or geographic region under the growth and non-growth (asset replacement and compliance) works programs. This allows the overall program to be optimised. For

[151] This is an IT program that focuses on the design, sourcing and execution of major enterprise level information systems implementation projects.
[152] section 6.52(iii), *Electricity Networks Access Code 2004.*
[153] Section 6.52(iii), *Electricity Networks Access Code 2004.*
[154] section 6.52(ii), *Electricity Networks Access Code 2004.*

example; a transformer may be scheduled for replacement under the asset replacement program as well as scheduled to be upgraded under the capacity expansion program. The model allows this duplication to be identified and ensures that the transformer is upgraded at the same time that it is replaced

- **deliverability assessment models** – determines total labour and material requirements underpinning the AA3 forecasts to then test against the capacity of each of our delivery channels and procurement options
- **investigation of non-network alternatives** – analyses the ability for non-network alternatives to support cost efficient deferral of capital expenditure for major augmentations. For example; we have used network control services to delay major augmentations in Ravensthorpe and forecast further use of network control services through AA3

8.3.3 Forecasting capital expenditure and contributions

We have forecast the cost of our capital works program using a combination of three methods:

1. project specific costing using building blocks cost estimates
2. unit costs for volume-based works
3. historical expenditure profiling

Figure 78 shows the proportion of our capital expenditure forecast using each method. These methods reflect the fact that capital expenditure mainly comprises specific, non-recurring projects, which can vary significantly over time and are dependent on demand and customer requirements.

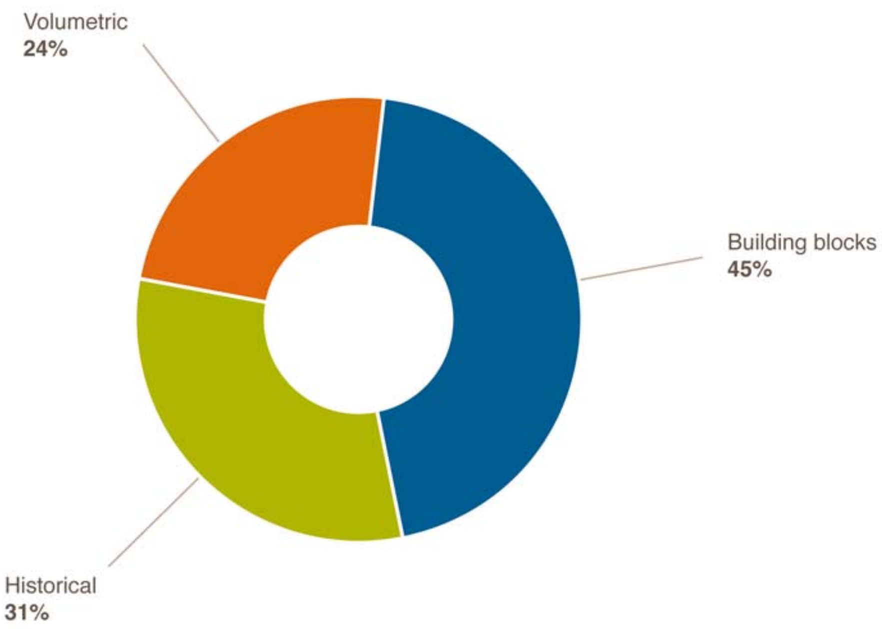

Figure 78: Percentage of capital expenditure by forecasting method

8.3.3.1 Project specific estimation

We have forecast the cost of many projects for AA3 using a project specific estimation method which involves the following steps:

a) determining the network issue or need

b) developing a suite of options to address the need

c) costing those options

d) selecting the lowest sustainable cost option

If options analysis is not feasible for projects, for example where they are in the very early stages of development, typical options that have addressed similar network issues in the past are selected and costed.

Transmission, distribution and corporate project cost estimates have been applied to the individual projects identified through the processes described in section 8.3.1 of this document. Project specific estimations have been built up by using individual cost estimates for each item within a project based on cost 'building blocks'. This accommodates any deviation in design requirements, enables greater customisation and allows for project variations.

Transmission building blocks

We have developed a set of cost 'building blocks' for estimating the cost of AA3 transmission capacity expansion projects and specific AA3 transmission projects in categories comprising SCADA and communications and regulatory compliance works.

The transmission building blocks are based on common elements such as substations and individual grades of line. The cost building blocks draw from standard design, typical engineering parameters and Technical Rules as well as historical cost data and expenditure. They provide a pool of itemised costs suitable for consolidation; to form larger scoped estimates, or to use for an individually run project.

The building blocks are prepared and maintained by our Estimating Centre. The Estimating Centre coordinates annual reviews of each building block, incorporating feedback from the project managers, estimators, and procurement staff. This provides the basis for regularly updating the building blocks for use in the business as usual project estimation processes and quotation processes.

We engaged independent experts Sinclair Knight Merz (SKM) to benchmark the current transmission building blocks that underpin the AA3 capital expenditure forecasts. The building block estimates for substations, lines and cables were compared to the costs of similar projects for other Australian utilities. SKM found that our cost estimates are within the 20% tolerance for substations, lines and cables are 'closely aligned with those in other states'.

Distribution building blocks

As with transmission, we have developed a set of cost 'building blocks' for estimating the cost of AA3 distribution capacity expansion projects. The distribution building blocks are based on common elements (also known as compatible units) such as pole top transformers and individual grades of line. Distribution works generally comprise smaller specific projects than transmission and have been forecast by analysing the individual cost components and aggregating them into projects or activities.

We have developed a distribution estimating tool based on compatible units, which draws from standard design, typical engineering parameters and Technical Rules as well as historical cost data and expenditure. It provides a database of distribution compatible units that can be combined to form the scope of the project and provide an itemised and costed list of requirements.

The distribution estimating tool and associated compatible units are prepared, maintained and reviewed annually by the Network Planning and Development Branch, incorporating feedback from the project managers, estimators, and procurement staff.

This provides the basis for routinely estimating and quoting distribution capacity expansion projects. The distribution compatible units are used to forecast the costs associated with specific projects and are maintained in a central database that is used for preparing discrete distribution project forecasts, annual works program forecasts and AA3 forecasts. It also provides a reference source to test market rates against on a more regular basis.

Corporate building blocks

Most of the AA3 corporate capital works programs have been continued from AA2. This means that we have a good understanding of the cost of the individual components that make up the corporate works program. The different costing methods are as follows:

- forecasts of the cost of specific AA3 projects have primarily been based on historical costs of similar projects and refined through analysis of the actual spend
- forecasts for larger planned works at sites (other than head office) have been developed based on estimates from building architects, quantity surveyors and similar quotes for works in progress
- forecasts for the IT capital expenditure program have regard to expected increases in user demand and economies of scale associated with larger user numbers

8.3.3.2 Volumetric estimation

Around one quarter of our capital investment program is forecast on the basis of unit costs applied to forecast work volumes. This approach has been applied primarily to the asset replacement and regulatory compliance expenditure categories, which are program based works.

These unit costs were developed in consultation with our relevant program sponsors and delivery partners and take into account the most recent delivered works, existing procurement contracts and current market rates. Unit costs were then tested against historical unit costs to ensure an appropriate market value.

8.3.3.3 Historical expenditure profiling

As discussed in section 8.3.1.1 of this document, customer-driven works have been forecast based on average historical expenditure, adjusted where appropriate for expected growth in new connections and other identifiable drivers.

8.3.4 Indirect network costs

As discussed in section 7.2.3 of this document, indirect network costs cover project management and coordination, and maintenance of computers and facilities for operational staff. They are allocated to activities and expensed or capitalised using the cost and revenue allocation method provided in Appendix E.

8.3.5 Forecasting contributions

We charge some customers a contribution towards the cost of connections in accordance with our approved capital contributions policy. We also receive gifted assets from certain connecting parties such as developers of new estates.

Contributions are charged where the capital costs associated with a new connection are not off-set by the incremental revenues that will be earned from the connection. The difference between these two is charged as a contribution. This is consistent with the requirements of section 5.14 (a) of the Access Code.

We have forecast AA3 capital contributions in a manner consistent with the method and assumptions used to forecast AA3 customer-driven capital expenditure. The approach uses average historical expenditure and average historical contributions rather than the incremental revenue test that is used to assess individual projects.

We consider that this is the most appropriate forecasting approach in the circumstances and is consistent with the Access Code provisions. The alternative approach of applying the incremental revenue test on a case by case basis is not possible given the uncertainty and any limited control we have over customer requirements.

Contributions for individual projects occurring during AA3 will be assessed on a case-by-case basis using Western Power's approved contributions policy for applying the incremental revenue test. Variations in contributions and investment will be addressed through the investment adjustment mechanism in AA4.

We have forecast AA3 contributions separately for:

- customer-initiated transmission capital works
- customer-initiated distribution capital works
- the State Underground Power Program (SUPP) works
- gifted assets from developers when new network segments are constructed (e.g., urban subdivisions)

Each of these forms of contribution has been forecast separately using the methods discussed below.

Transmission contributions

Transmission contributions are forecast assuming a 50% contribution rate.[155] While actual capital contributions will be assessed on a case-by-case basis, this forecasting assumption reflects the recoveries of a sample set of transmission projects between 2001 and 2011, noting the highly variable expenditure associated with customer-driven work.

This forecasting method is consistent with using the historical average expenditure to forecast transmission customer-driven capital expenditure. It also avoids the need to identify the most likely projects from the existing applications, in an uncertain environment.

Distribution contributions

Distribution contributions are forecast assuming a 35% contribution rate. This rate reflects the historical recovery rate for capital contributions from distribution customers. As with the transmission contributions, this forecasting method aligns with using historical average expenditure to forecast distribution customer-driven capital expenditure.

[155] Except for transmission line relocations which are assumed to have a 100% contribution rate.

Given the small scale and high volume nature of distribution customer-driven works, expenditure levels and contribution rates are fairly stable over time. This provides a high degree of predictability and supports using historical levels as the forecasting method.

SUPP contributions

Our contributions to the agreed AA3 expenditure on SUPP are forecast in accordance with a capital and operating cost sharing agreement between:

- State Government – 50%
- local governments – 25%
- Western Power – 25%

Gifted asset contributions

Gifted assets have been forecast based on the historical volumes and considering land development and lot clearing projections from other utilities and Government planning agencies. The gifted assets contribution is based on an internal estimate of the 'fair value' of the construction cost, rather than on the actual cost incurred by the third party.

8.3.6 Adjusting for forecast movements in the market price of labour and materials

We have escalated the forecast capital expenditure for forecast real growth in the cost of labour and materials. The input cost escalation factors were developed by independent experts, CEG. Section 7.2.5 of this document provides an overview of our input cost escalation method. CEG's report is provided in Appendix W.1.

Table 42 sets out the dollar impact of forecast movements in labour and materials input costs for capital expenditure over the AA3 period.

Table 42: Impact of forecast movements in labour and materials costs on capital expenditure

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total
Labour escalation[156]	13.9	31.9	57.5	85.9	99.1	288.3
Materials escalation	-0.3	0.7	2.8	4.6	5.2	13.0
Total input cost escalation	13.7	32.7	60.3	90.5	104.2	301.3

[156] The labour escalation relates to both internal and external labour.

8.4 Transmission capital expenditure

In AA3, Western Power proposes to invest $1.927 billion of capital in the transmission network (see Table 43).

Table 43: Transmission capital expenditure by regulatory category

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3	% of transmission capital
Growth	290.7	206.3	290.9	440.6	326.7	1,551.2	80.7%
Asset replacement and renewal	30.8	33.9	34.8	35.4	37.8	172.6	9.0%
Compliance	14.3	17.3	24.8	31.5	32.8	120.7	6.3%
Improvement in service	14.4	12.2	13.5	19.3	19.4	78.8	4.1%
Total capital expenditure	**350.2**	**269.7**	**363.9**	**526.9**	**416.7**	**1.927.3**	**100.0%**
Less contributions	41.4	41.8	42.5	43.1	44.7	213.6	11.1%
Transmission capital expenditure to be added to the capital base	**308.7**	**227.9**	**321.4**	**483.7**	**372.0**	**1,713.7**	**88.9%**

Capital expenditure on electricity networks is inherently lumpy. Projects that expand capacity and improve security, particularly on the transmission network, happen infrequently yet provide large tranches of capacity to meet future growth.[157]

The vast majority ($1.555 billion) of our AA3 capital investment is driven by forecast load growth, which is triggered by customer requirements ($378 million) and requirements of the technical rules and planning criteria ($1.177 billion). Investment to meet growth requirements includes upgrading existing infrastructure and installing new/additional infrastructure on the transmission network.

The remaining forecast capital expenditure is not related to growth and reflects our need to maintain the performance of the existing assets and continue to comply with regulatory and legislative obligations as well as technical requirements.

Figure 79 shows the capital expenditure that we will incur on the transmission network by regulatory category, and a comparison with historical expenditure.

[157] This capacity lumpiness is recognised by clause 6.52(ii) of the Access Code which requires consideration of the efficiency capacity increments having regard to a reasonable period of time.

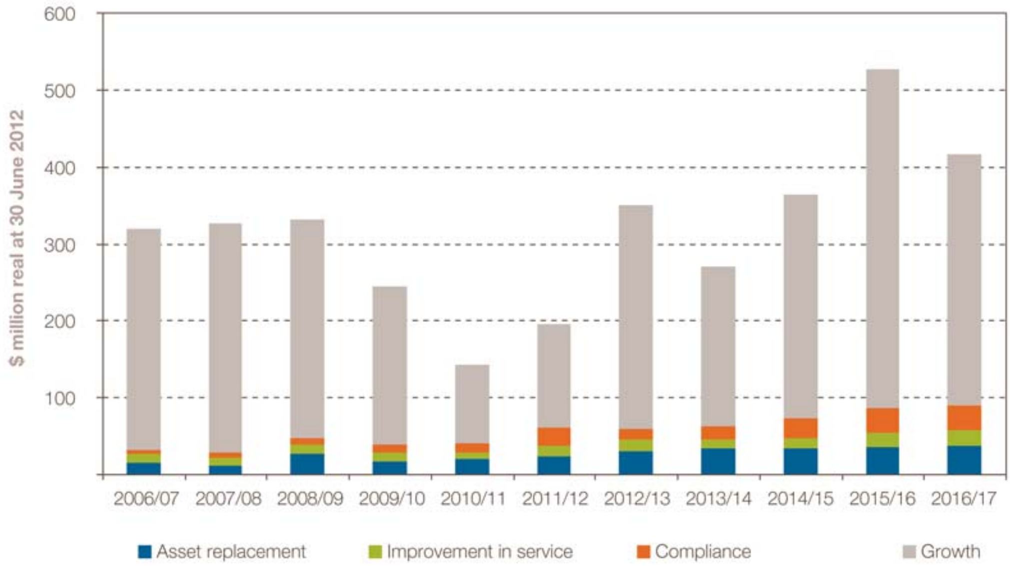

Figure 79: Transmission expenditure historical trend by regulatory category

The increase in expenditure in AA3 compared to AA2 will:

- expand system capacity to meet a predicted increase in peak demand from 3639 MW in 2009/10 to 5061 MW by the end of AA3
- deliver a significant part of the Mid-West Energy Project to increase power transmission capacity between Perth and Geraldton to meet increased peak demand and generation capacity in the region
- reduce the number of customers at risk of supply interruptions due to single outages of transmission infrastructure to 100,000 by the end of AA3
- restore system security in order to meet our legislative obligations by increasing the capacity through the upgrading of existing infrastructure
- replace 35% of the indoor circuit breaker population[158]
- replace the Muja to Merredin microwave bearer and commence the Goldfield Alcatel microwave replacement[159]
- continue the transmission pole replacement and reinforcement programs in accordance with Energy*Safety* Order 01-2009, replacing 4,000 transmission poles through AA3

The forecast expenditure considers the key regulatory obligations drive our transmission growth capital expenditure.

[158] In the past ten years, four catastrophic failures of circuit breakers in pitch-filled type switchboards have contributed to over a third of our indoor circuit breaker population being assessed as being in poor or bad condition and in need of replacement.
[159] These radio systems extend the communications backhaul network through areas where the use of optical fibre or other cables is uneconomical.

Transmission growth obligations
Key regulatory obligations driving transmission growth expenditure include:

Section 2.7 of the Access Code
A service provider for a covered network must use all reasonable endeavours to accommodate an applicant's:

a) *requirement to obtain covered services; and*

b) *requirements in connection with the negotiation of an access contract*

Section 2.8 of the Access Code
Without limiting section 2.7 a service provider must:

a) *comply with the access arrangement for its covered network and must expeditiously and diligently process access applications; and*

b) *negotiate in good faith with an applicant regarding the terms for an access contract; and*

c) *to the extent reasonably practicable in accordance with good electricity industry practice, permit an applicant to acquire a covered service containing only those elements of the covered service which the applicant wishes to acquire; and*

d) *to the extent reasonably practicable, specify a separate tariff for an element of a covered service if requested by an applicant, which tariff must be determined in accordance with sections 10.23 and 10.24; and*

e) *when forming a view as to whether all or part of any proposed new facilities investment meets the test in section 6.51A, form that view as a reasonable and prudent person.*

Wholesale Electricity Market Rules requires generators to have access to Western Power's network on an unconstrained basis. This requires higher investment than would otherwise apply in a market where access is provided on a constrained basis.

Section 2.5.1 of the Technical Rules
The Network Service Provider must design connection assets in accordance with a User's requirements and the relevant requirements of section 3.

Table 44 shows the amount of capital expenditure we will incur over the AA3 regulatory on transmission growth related projects, namely $1.555 billion[160]. This is necessary to fulfil regulatory obligations to connect customers and provide covered services.

Table 44: Transmission growth capital expenditure by regulatory category

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3	% of transmission growth
Capacity expansion	217.3	132.3	215.7	364.3	247.7	1,177.3	75.7%
Customer-driven	73.4	74.0	75.2	76.3	79.0	377.9	24.3%
Total transmission growth capital expenditure	290.7	206.3	290.9	440.6	326.7	1555.3	
Less contributions from customers	41.4	41.8	42.5	43.1	44.7	213.6	13.7%
Transmission capital expenditure to be added to the capital base	**249.2**	**164.5**	**248.4**	**397.5**	**282.1**	**1,341.7**	**86.3%**

The transmission growth category of work includes:

[160] Inclusive of capital contributions from customers.

- **capacity expansion** ($1.177 billion) – to meet forecast load growth and maintain the security of the network influenced by the requirements of the Technical Rules including planning criteria. This work involves upgrading existing infrastructure and installing new/additional infrastructure on the transmission network. This includes $244 million in expenditure for the Mid West Energy Project.
- **customer-driven** ($378 million) – to meet the requirements of individual customers. This work provides the connection between transmission connected customer premises and the network and is usually funded by the customer directly. The contributions for customer-driven works are forecast to be $214 million

Figure 80 shows the proportion of transmission growth capital expenditure that is being driven by capacity expansion versus customers. It also shows the significant increase in overall transmission growth capital expenditure compared to AA2. The $164 million increase in gross annual average expenditure when compared with AA2 will allow Western Power to commence the critical projects deferred from AA2, address deteriorating system security and cater for the customer-driven projects delayed during the economic downturn.

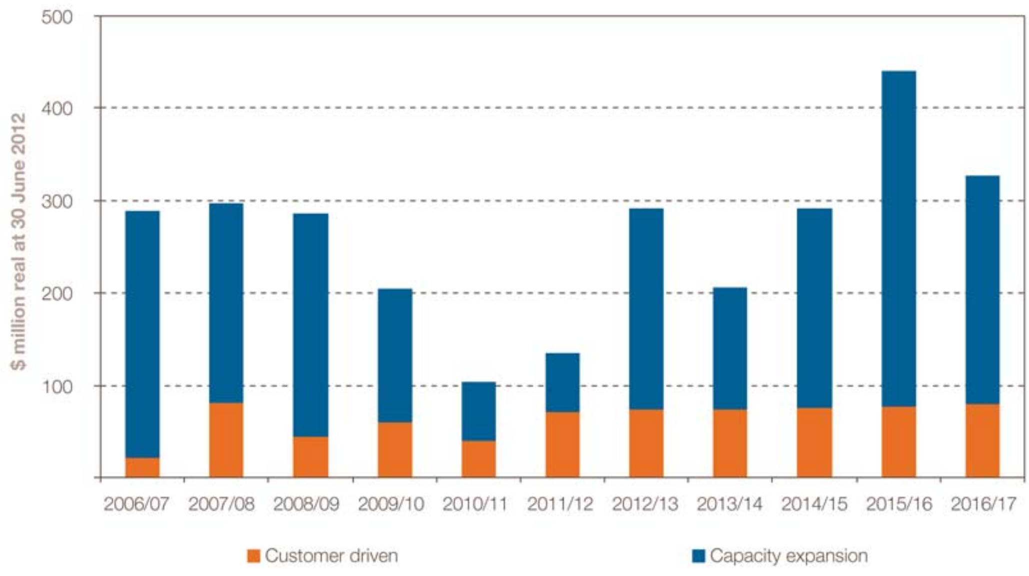

Figure 80: Transmission growth capital expenditure by regulatory category

As transmission customer-driven works are driven by demand and often rely on financing of large industrial projects, expenditure in this category is highly volatile. Capacity expansion projects in AA2 were affected by a slow down in customer work and a reprioritisation of the work program following a governance and efficiency review. These factors, combined with the deferral of several major projects led to a lower level of capital investment than originally forecast and subsequently endorsed by the Authority. However, investment in capacity expansion will increase significantly in AA3 and will be more aligned with expenditure levels in AA1.

In AA3, transmission growth capital expenditure will focus on maintaining supply and expanding capacity to meet the growing demand for energy through increasing the capacity of lines, substations and feeders. This is particularly important to ensure our ongoing ability to support the growth of existing residential and small business loads on the Western Power Network despite the lower than forecast expenditure in AA2.

In addition, we will complete a significant portion of the Mid-West Energy Project. This requires $244 million in the AA3 period to provide additional transmission line capacity between Perth and Geraldton. This will accommodate the natural load growth (particularly in the Geraldton area) and support system security by increasing the capacity of the existing transmission network.

To manage the overall level of capital investment in AA3, we will also use network control services to allow the procurement of generation in localised areas of network constraint and thereby defer the need for more costly network augmentation (see section 7.4.3 of this document).

8.4.1 Transmission non-growth

Less than 20% of our total transmission capital expenditure is not growth related. Transmission non-growth work is largely driven by the replacement of critical transmission assets and the need to avoid further deterioration of the transmission network. It also reflects expenditure required to comply with regulatory obligations and to maintain service across a growing network through continuous improvements in SCADA and communications.

In undertaking transmission non-growth works, we aim to:

- reduce the risk of plant failure particularly with respect to critical (non run-to-failure) assets to ensure we maintain covered services to customers
- invest in network assets as required by our network management plan to ensure asset management and operational requirements are met
- comply with relevant safety, environmental and service obligations

Transmission non-growth obligations
Our forecast transmission non-growth capital expenditure reflects our obligations under a number of significant pieces of legislation including:

Section 14(1) of the *Electricity Industry Act 2004*
It is a condition of every licence, other than a retail licence, that the licensee must:

a) provide for an asset management system in respect of the licensee's assets;

Safety – Regulation 10(1) of the *Electricity (Supply Standards and System Safety) Regulations 2001*
A network operator must ensure that each prescribed activity is, so far as is reasonable and practicable, carried out in such a way as to:

a) provide for the safety of persons, including employees of and contractors to the operator;

b) avoid or minimise the exposure of persons, including employees of and contractors to the operator, to electric and magnetic field effects; and

c) avoid or minimise any damage to property, inconvenience or other detriment as a result of the activity

Regulation 11(1) of the Electricity (Supply Standards and System Safety) Regulations 2001
Compliance by a network operator to whom Division 2 applies with a relevant provision of:

a) a standard or code published under a law any jurisdiction in Australia

b) a standard or code published by Standards Australia, the Electricity Supply Association of Australia, or any other body approved by the Director

c) a standard or code published by any other body and approved by the Director

d) a standard or code published specified in Schedule 2.

Section 9 of the Electricity Industry (Network Quality and Reliability of Supply) Code 2005
A transmitter or distributor must, so far as is reasonably practicable, ensure that the supply of electricity to a customer is maintained and the occurrence and duration of interruptions is kept to a minimum.

Section 10(1) of the Electricity Industry (Network Quality and Reliability of Supply) Code 2005
A transmitter or distributor must, so far as is reasonably practicable, reduce the effect of any interruption on a customer.

Transmission non-growth obligations

Section 3.2.8 of the Wholesale Electricity Market Rules
System Management must operate the SWIS in accordance with the Power System Operation Procedure and the Technical Envelope for the applicable SWIS Operating State.

Section 2.9.1 of the Technical Rules

a) *All primary equipment on the transmission and distribution system must be protected so that if an equipment fault occurs, the faulted equipment item is automatically removed from service by the operation of circuit breakers or fuses. Protection systems must be designed and their settings coordinated so that, if there is a fault, unnecessary equipment damage is avoided and any reduction in power transfer capability or in the level of service provided to Users is minimised.*

b) *Consistent with the requirement of clause 2.9.1(a), protection systems must remove faulted equipment from service in a timely manner and ensure that, where practical, those parts of the transmission and distribution system not directly affected by a fault remain in service.*

c) *Protection systems must be designed, installed and maintained in accordance with good electricity industry practice. In particular, the Network Service Provider must ensure that all new protection apparatus complies with IEC Standard 60255 and that all new current transformers and voltage transformers comply with AS 60044 (2003).*

Section 2.9.2 of the Technical Rules

a) *Transmission system*

   1. *Primary equipment operating at transmission system voltages must be protected by a main protection system that must remove from service only those items of primary equipment directly affected by a fault. The main protection system must comprise two fully independent protection schemes of differing principle. One of the independent protection schemes must include earth fault protection.*

   2. *Primary equipment operating at transmission system voltages must also be protected by a back-up protection system in addition to the main protection system. The back-up protection system must isolate the faulted primary equipment if a small zone fault occurs, or a circuit breaker failure condition occurs. For primary equipment operating at nominal voltages of 220 kV and above the back-up protection system must comprise two fully independent protection schemes of differing principle that must discriminate with other protection schemes. For primary equipment operating at nominal voltages of less than 220kV the back-up protection system must incorporate at least one protection scheme to protect against small zone faults or a circuit breaker failure. For protection against small zone faults there must also be a second protection scheme and, where this is co-located with the first protection scheme, together they must comprise two fully independent protection schemes of differing principle.*

   3. *The design of the main protection system must make it possible to test and maintain either protection scheme without interfering with the other.*

   4. *Primary equipment operating at a high voltage that is below a transmission system voltage must be protected by two fully independent protection systems in accordance with the requirements of clause 2.9.2(b)(1).*

Section 2.9.3 of the Technical Rules

a) *All protection schemes, including any back-up or circuit breaker failure protection scheme, forming part of a protection system protecting part of the transmission or distribution system must be kept operational at all times, except that one protection scheme forming part of a protection system can be taken out of service for period of up to 48 hours every 6 months.*

b) *Should a protection scheme forming part of the main or back-up protection system protecting a part of the transmission system be out of service for longer than 48 hours, the Network Service Provider must remove the protected part of the transmission system from service unless instructed otherwise by System Management.*

c) *Should either the two protection schemes protecting a part of the distribution system be out of service for longer than 48 hours, the Network Service Provider must remove the protected part of the distribution system from service unless the part of the distribution system must remain in service to maintain power system stability.*

Schedule 3 of the Telecommunications Act 1997
A carrier may enter on land and exercise any of the following powers:

- *the power to inspect the land to determine whether the land is suitable for the carrier's purposes;*
- *the power to install a facility on the land;*
- *the power to maintain a facility that is situated on the land.*

In AA3, we will undertake $372 million or 19% of total transmission capital expenditure to maintain the transmission network as shown in Table 45.

Table 45: Transmission non-growth capital expenditure by regulatory category

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3	% of transmission non-growth
Asset replacement and renewal	30.8	33.9	34.8	35.4	37.8	172.6	46.4%
Compliance	14.3	17.3	24.8	31.5	32.8	120.7	32.4%
Improvement in service	14.4	12.2	13.5	19.3	19.4	78.8	21.2%
Transmission non-growth expenditure	**59.5**	**63.4**	**73.0**	**86.2**	**89.9**	**372.1**	**100.0%**

The transmission non-growth expenditure reflects the following categories of expenditure[161]:

- **asset replacement and renewal** ($173 million) – to reduce the risk of plant failure affected by the age, condition and performance of individual assets.
- **regulatory compliance** ($121 million) – to meet external regulatory and legislative obligations, including technical and safety requirements
- **improvement in service**[162] ($79 million) – to enable the real-time monitoring and automation of our transmission assets

[161] Further information on the regulatory categories is provided in Appendix A: AA3 capital and operating expenditure report.
[162] Western Power has no planned investment in transmission reliability driven works. In AA3, we will undertake a large program of work to address security (and hence improve reliability). However, this is part of our transmission capacity expansion program, acknowledging the contribution of growth in demand and energy consumption increasing the risk of widespread, long duration outages.

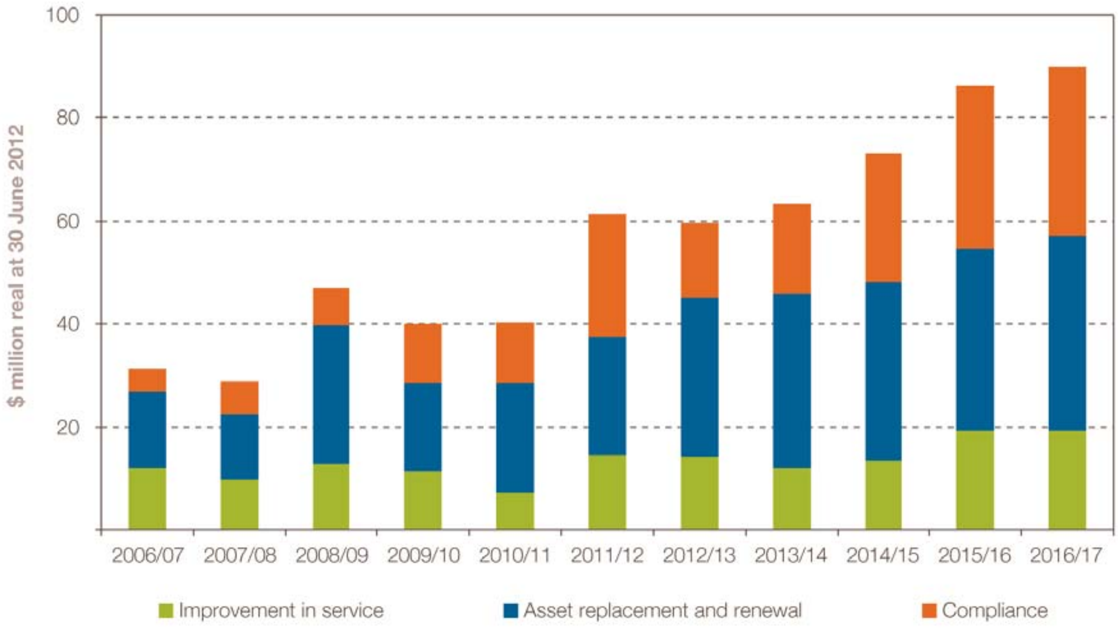

Figure 81: Transmission non-growth expenditure by regulatory category

In AA3, we will continue our major asset replacement strategies, compliance works and replacement and refurbishment of our SCADA and communications infrastructure. This includes:

- **asset replacement and renewal** – replacing 208 circuit breakers (8 of 18 indoor and all 190 outdoor circuit breakers no longer supported by the manufacturer and in bad condition) to prevent costly damage from unplanned failure, following four catastrophic failures during AA2
- **compliance** – replacing and reinforcing 19% of the transmission pole population in accordance with Energy*Safety* Order 01-2009
- **asset replacement and renewal** – replacing 450 (2% of the population) current transformers to address those with known issues and at risk of failure or pose safety and environmental risks
- **improvement in service** – upgrading the XA/21 master station hardware, which has exceeded its standard industry life to reduce the threat of failure

8.5 Distribution capital expenditure

In AA3, we will invest $3.581 billion of capital in the distribution network. $744 million of this is forecast to be recovered from customer contributions and will therefore not be added to the capital base (see Table 46). The effect of the capital contributions is to ensure other customers do not pay for investment required by individual customers.

Table 46: Distribution capital expenditure by regulatory category

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3	% of distribution capital
Growth	338.5	348.5	369.9	374.8	386.7	1,818.3	50.8%
Asset replacement and renewal	217.5	264.3	257.3	260.6	244.9	1,244.6	34.8%
Compliance	100.7	107.3	110.4	79.3	87.6	485.3	13.6%
Improvement in service	5.5	6.6	7.7	4.8	8.2	32.9	0.9%
Total expenditure	662.3	726.7	745.3	719.4	727.4	3,581.1	100%
Less contributions	166.4	151.6	140.3	141.5	144.2	744.0	20.8%
Distribution capital expenditure to be added to the capital base	**495.9**	**575.1**	**605.0**	**578.0**	**583.2**	**2,837.2**	**79.2%**

The drivers of capital expenditure in the distribution network are[163]:

- **growth** ($1.818 billion) – forecast load growth expenditure is triggered by customer requirements ($1.404 billion) and requirements of the Technical Rules and planning criteria ($414 million). This work involves upgrading existing infrastructure and installing new/additional infrastructure on the distribution network. In AA3, this work is primarily aimed at increasing capacity to meet the forecast maximum peak demand. Although system peak demand is growing at 3.2% per year, it is the growth in demand at each substation that drives the need for additional investment. Growth by substation varies considerably across our network assets. We must also connect an additional 130,000 (or 13%) new distribution customers. $700 million of this is forecast to be provided in customer contributions
- **asset replacement and renewal** ($1.245 billion) – driven by the age, condition and performance of individual assets including expenditure to reduce the risk of plant failure. This category includes our pole replacement and reinforcement program which is the largest component ($748 million), the replacement of the non-compliant three phase meters and the supporting communications infrastructure ($91 million) and Stage 5 of the State Underground Power Program (SUPP) ($58 million) of which $44 million is forecast to be received in contributions from customers and Government
- **compliance** ($485 million) – required to meet our external regulatory and legislative obligations, including technical and safety requirements on the distribution network

[163] More information for each regulatory category is provided in Appendix A: AA3 capital and operating expenditure report.

- **improvement in service**[164] ($33 million) – to enable the real-time monitoring and automation (SCADA and communications) of our distribution assets

Figure 82 shows the capital expenditure that we will incur on the distribution network by regulatory category, and a comparison with historical expenditure.

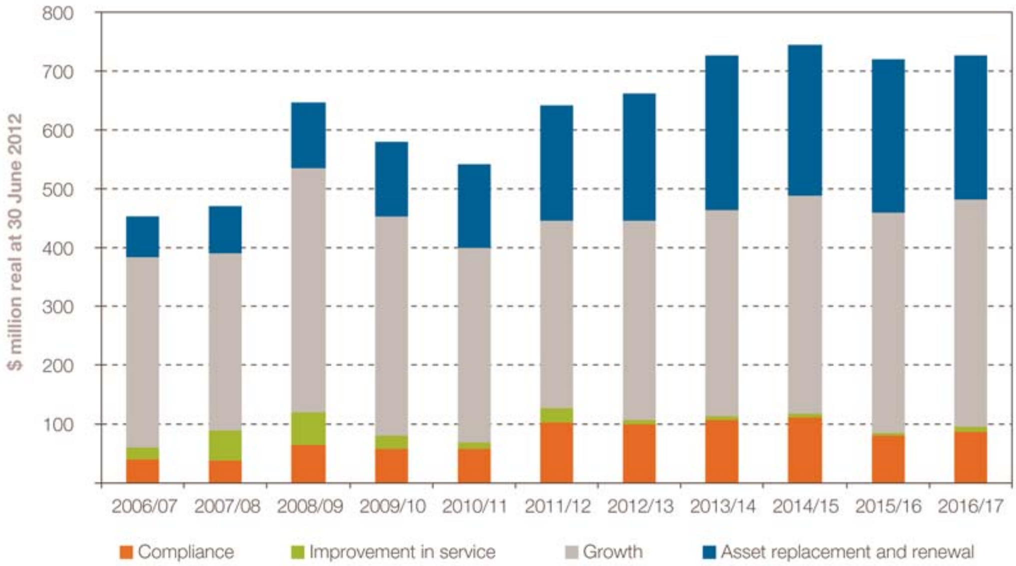

Figure 82: Total distribution capital expenditure by regulatory category

The distribution works will:

- reduce the number of customers at risk of widespread, long duration outages because of a fault due to insufficient distribution transfer capacity
- reduce the number of customers exposed to voltage constraints which lead to outages and equipment damage
- continue the distribution pole programs, reinforcing and replacing 26% of our distribution poles, in line with requirements under the Energy*Safety* Order (01-2009) to move towards the industry benchmark levels for unassisted distribution pole failure
- continue the bushfire mitigation program, targeting sources of pole top fires, conductor clashing, equipment failure and wires down in extreme and high risk fire areas to reduce the likelihood of asset initiated fires
- improve the condition of our overhead wire population to reduce the likelihood of public safety incidents (including electric shocks and fires) and reduce the risk of poor distribution reliability as a result of wires falling
- replace non-compliant three-phase meters with smart meters and provide SCADA and communications equipment to enable the realisation of the full benefits associated with the installation of smart meters
- ensure compliance with environmental obligations including transformer bunding and noise mitigation works[165]

[164] There is no investment included specifically targeting average reliability for the AA3 period.

- maintain compliance with the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*, which requires that small use customers must not experience more than one twelve hour duration every ten years. Related works include automating existing switching points and protective devices, installing new interconnectors between feeders and adding telemetry to existing protective devices
- maintain compliance with the *Electricity Act 1945* by addressing voltage levels that have become non-compliant as a result of subdivision of land in inner metropolitan and semi-rural areas. 1,500 multi-customer LV networks will be addressed over a sustained 10 – 15 year program

8.5.1 Distribution growth

In AA3, we will invest $1.818 billion in projects to respond to growth impacts on the distribution network. Of this, $700 million will be funded by customers where capital costs associated with projects are not offset by incremental revenue (see Table 47).

Table 47: Distribution growth capital expenditure by regulatory category

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3	% of distribution growth
Customer access	207.9	209.0	217.3	220.5	228.3	1,083.0	59.6%
Capacity expansion	66.3	75.2	88.3	90.0	94.1	413.9	22.8%
Gifted assets	64.3	64.3	64.3	64.3	64.3	321.3	17.7%
Total distribution growth capital expenditure	**338.5**	**348.5**	**369.9**	**374.8**	**386.7**	**1,818.3**	**100.0%**
Less contributions from customers	137.0	137.4	140.3	141.5	144.2	700.4	38.5%
AA3 distribution growth capital expenditure to be added to the capital base	**201.4**	**211.1**	**229.5**	**233.3**	**242.5**	**1,117.9**	**61.5%**

Growth-related investment represents 51% of total distribution capital expenditure. $1.404 billion in expenditure is required for distribution customer-driven works which we are obliged to undertake. The remaining $414 million is driven by the growth in demand.

Approximately 3% of the distribution growth expenditure is related to transmission expansion activities. In contrast to transmission growth work, distribution growth expenditure generally comprises a relatively large number of small projects and is reasonably stable over the period, reflecting the consistent growth in demand.

[165] See Appendix B.2: AA2 project and program variance analysis and commentary.

Distribution growth obligations
Key regulatory obligations driving distribution growth expenditure include:

Section 2.7 of the Access Code
A service provider for a covered network must use all reasonable endeavours to accommodate an applicant's:
a) requirement to obtain covered services; and
b) requirements in connection with the negotiation of an access contract.

Section 2.8 of the Access Code
Without limiting section 2.7 a service provider must:
a) comply with the access arrangement for its covered network and must expeditiously and diligently process access applications; and
…
e) when forming a view as to whether all or part of any proposed new facilities investment meets the test in section 6.51A, form that view as a reasonable and prudent person.

Wholesale Electricity Market Rules *requires generators to have access to Western Power's network on an unconstrained basis. This requires higher investment than would otherwise apply in a market where access is provided on a constrained basis.*

Section 2.5.1 of the Technical Rules
The Network Service Provider must design connection assets in accordance with a User's requirements and the relevant requirements of section 3.

Section 2.6 of the Technical Rules
All distribution systems must be designed to supply the maximum reasonably foreseeable load anticipated for the area served. The maximum reasonably foreseeable load must be determined by estimating the peak load of the area after it has been fully developed, taking into account restrictions on land use and assuming current electricity consumption patterns.

The distribution growth category of work includes:

- **customer access** ($1.083 billion) – the majority of this work is to meet the requirements of individual customers in line with our obligations and includes new or modified connections, network expansion, subdivisions and asset relocations. Customers requesting specific works are often required to make a contribution to the cost of the works. $698 million is expected to be recovered directly from customers.
- **capacity expansion** ($414 million) – to meet the requirements of the Technical Rules and planning criteria, with the main trigger for investment being forecast load growth (see section 6.2 of this document). This work involves expanding the network through installation of new or additional infrastructure and upgrading existing assets on the distribution network
- **gifted assets** ($321 million) – network assets built by developers (residential and commercial subdivisions), which are then transferred to Western Power to own and operate. Gifted assets are not added to the capital base because we do not incur the cost of construction

In order to support the expenditure in AA3, we will also use network control services to defer augmentations.

Figure 83 shows the AA3 expenditure segregated by regulatory category.

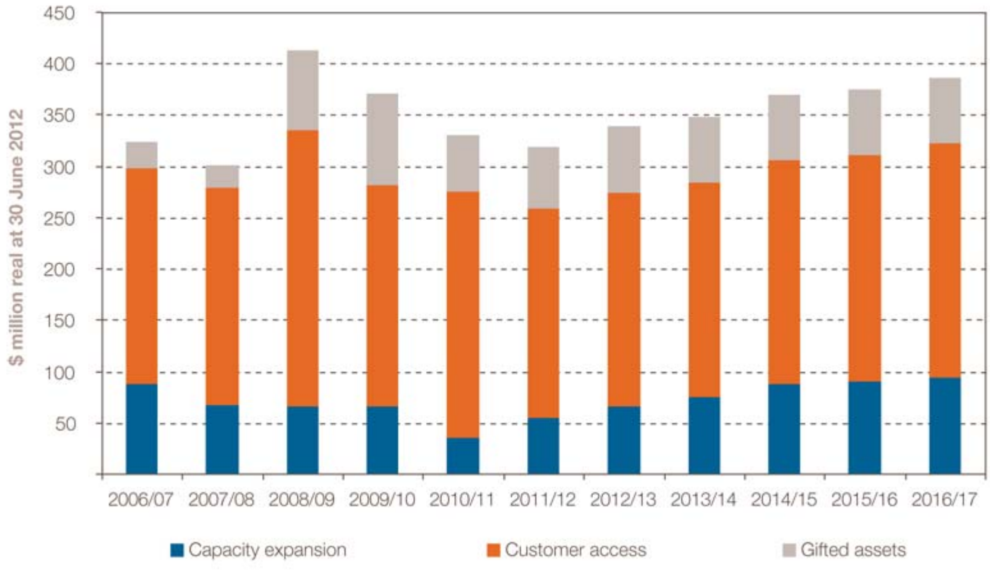

Figure 83: AA3 distribution growth expenditure historical trend by regulatory category

8.5.2 Distribution non-growth

Approximately ($1,763 million) 49% of Western Power's proposed distribution capital expenditure relates to non-growth activities. This expenditure aims to:

- reduce the risk of plant failure particularly with respect to critical (non run-to-failure) assets to ensure we maintain covered services to customers
- invest in network assets as required by our network management plan to ensure efficient and effective asset management and operation
- comply with relevant safety, environmental and service obligations

Distribution non-growth obligations
Forecast distribution non-growth capital expenditure reflects our obligations under a number of significant pieces of legislation including:

Section 14(1) of the *Electricity Industry Act 2004*
It is a condition of every licence, other than a retail licence, that the licensee must:
- *a) provide for an asset management system in respect of the licensee's assets;*

Section 25(1)(a) of the *Electricity Act 1945*
A network operator shall - at all times maintain all service apparatus belonging to the network operator which is on the premises of any consumer, in a safe and fit condition for supplying electricity

Regulation 10(1) of the Electricity (Supply Standards and System Safety) Regulations 2001
A network operator must ensure that each prescribed activity is, so far as is reasonable and practicable, carried out in such a way as to:
- *a) provide for the safety of persons, including employees of and contractors to the operator;*
- *b) avoid or minimise the exposure of persons, including employees of and contractors to the operator, to electric and magnetic field effects; and*
- *c) avoid or minimise any damage to property, inconvenience or other detriment as a result of the activity.*

Regulation 11(1) of the Electricity (Supply Standards and System Safety) Regulations 2001
Compliance by a network operator to whom Division 2 applies with a relevant provision of:
- *a) a standard or code published under a law any jurisdiction in Australia*
- *b) a standard or code published by Standards Australia, the Electricity Supply Association of Australia, or any other body approved by the Director*
- *c) a standard or code published by any other body and approved by the Director*
- *d) a standard or code published specified in Schedule 2.*

Section 9 of the Electricity Industry (Network Quality and Reliability of Supply) Code 2005
A transmitter or distributor must, so far as is reasonably practicable, ensure that the supply of electricity to a customer is maintained and the occurrence and duration of interruptions is kept to a minimum.

Section 10(1) of the Electricity Industry (Network Quality and Reliability of Supply) Code 2005
A transmitter or distributor must, so far as is reasonably practicable, reduce the effect of any interruption on a customer.

Section 3.5(3) of the Electricity Industry Metering Code 2005
A network operator must, for each metering installation on its network, on and from the time of its connection to the network:

- *a) unless otherwise agreed between the network operator and a user, provide, install, operate and, subject to clause 3.5(7), maintain the metering installation in accordance with:*
  - *i. this Code; and*
  - *ii. good electricity industry practice; and*
  - *iii. the metrology procedure for the network; and*
  - *iv. the service level agreement between the network operator and the user in respect of the metering installation; and*
- *b) ensure that the metering installation complies with clause 3.9; and*
- *c) without limiting clause 3.5(3) (a) ensure that the metering equipment in the metering installation:*
  - *i. is suitable for the range of operating conditions to which it will be exposed (e.g. temperature, impulse levels); and*
  - *ii. operates within the defined limits for that metering equipment as specified in the approved metrology procedure.*

Sections 3.2.8 of the Wholesale Electricity Market Rules
System Management must operate the SWIS in accordance with the Power System Operation Procedure and the Technical Envelope for the applicable SWIS Operating State.

Sections 2.9.1 of the Technical Rules
- *a) All primary equipment on the transmission and distribution system must be protected so that if an equipment fault occurs, the faulted equipment item is automatically removed from service by the operation of circuit breakers or fuses. Protection systems must be designed and their settings coordinated so that, if there is a fault, unnecessary equipment damage is avoided and any reduction in power transfer capability or in the level of service provided to Users is minimised.*
- *b) Consistent with the requirement of clause 2.9.1(a), protection systems must remove faulted equipment from service in a timely manner and ensure that, where practical, those parts of the transmission and distribution system not directly affected by a fault remain in service.*
- *c) Protection systems must be designed, installed and maintained in accordance with good electricity industry practice. In particular, the Network Service Provider must ensure that all new protection apparatus complies with IEC Standard 60255 and that all new current transformers and voltage transformers comply with AS 60044 (2003)*

Table 48 provides an overview of investment in non-growth activities during the AA3 period.

Table 48: Distribution non-growth capital expenditure by regulatory category

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	Total AA3	% of distribution non-growth
Asset replacement and renewal	217.5	264.3	257.3	260.6	244.9	1,244.6	70.6%
Compliance	100.7	107.3	110.4	79.3	87.6	485.3	27.5%
Improvement in service	5.5	6.6	7.7	4.8	8.2	32.9	1.9%
Distribution non-growth expenditure	**323.8**	**378.2**	**375.4**	**344.7**	**340.7**	**1,762.8**	**100.0%**

The majority (71%) of distribution non-growth capital expenditure is associated with asset replacement and renewal ($1.245 billion). This expenditure is required to reduce the risk of plant failure associated poor performing and poor condition assets. Plant failure impacts on several areas of performance on the network including safety, reliability, environment, nearby assets, and creates operational issues. The increase in asset replacement and compliance expenditure is largely driven by the significant costs associated with our priority safety programs, for example:

- **wood poles** – introducing the necessary increase in pole replacements and reinforcements to reduce the incidence of unassisted pole failures in response to Energy*Safety* Order 01-2009 and in line with our wood pole management plan
- **conductors** – to replace aged and deteriorated wires and cables, particularly corroded steel-based conductors and small cross sectional area copper conductors
- **overhead customer service connections** – complete the replacement of at risk service connections by 2015/16

We also have a unique opportunity during AA3 to move towards a ‘smart’ future. During AA3 there are 280,000 three-phase electricity meters that are non-complaint with the Metering Code and must be replaced.

Over recent years we have taken a watching brief on smart grid developments in other states. We believe it is now appropriate to seize this opportunity and consider replacing these non-compliant meters with ‘smart’ meters and providing supporting communications and supporting IT infrastructure. We will also install communications and IT for all other three-phase meters that are new and or replaced during the period.

This means we can take a huge step towards developing a ‘smart grid’. This will deliver benefits to both customers and achieve network planning and operating efficiencies while establishing an adaptable platform on which new applications (such as electric vehicles) can be cost-effectively managed. We will also continue to investigate emerging technology that can improve the effectiveness of demand-side management and ‘smart’ energy solutions. $91 million of distribution non-growth capital will be invested in this project (see Appendix R: smart grid proposal for more information).

The remaining 29% of distribution non-growth expenditure (see Figure 84) is for:

- **regulatory compliance** ($485 million) – expenditure to meet our external regulatory and legislative obligations, including technical and safety requirements

- **improvement in service** ($33 million) – to enable the real-time monitoring and automation of our distribution assets (SCADA and communications)

Figure 84: Distribution non-growth capital expenditure by regulatory category

8.6 Deliverability of the capital works program

We will be able to deliver the proposed work program in the AA3 period. We have undertaken extensive analysis to ensure that the scale and scope of the works is able to be delivered in an efficient and effective manner. We have achieved this by:

- ensuring the timing of projects reflects a realistic timeframe for receiving all external and internal planning and process
- assessing work levels (magnitude of work by type and work activity) and mix (internal or external capabilities) in accordance with the works delivery framework. This has also taken into account: viable work loads, overall and year on year works program variation, uncertainty of customer funded projects and delivery risk
- surveying the market to satisfy ourselves that our external service providers have the capacity to acquire the increased skilled labour requirements and that there is sufficient interest in the large transmission projects to attract competitive tenders
- analysing our labour attrition and training requirements to ensure we have the appropriate skills and factor the costs associated with these requirements into our forecasts
- bundling works by type and geographic location to achieve economies of scale
- leveraging our purchasing power to ensure we can procure materials efficiently

Our Works Delivery Strategy, attached at Appendix M provides an assessment of our ability to leverage domestic and global resources to effectively manage the labour and material requirements. It also supports our ability to deliver higher work volumes.

We have worked closely with key government stakeholders to inform them of our investment plans and funding requirements to improve the certainty of obtaining funds when they are required.

In summary, the following factors ensure we can and will deliver the proposed works program:

- **network risk dictates that this investment *must* be undertaken** – our network cannot sustain the safety and security risk associated with not delivering this investment program. In many cases this means that the cost of not undertaking the works could be higher than the cost of doing the work. We are committed to key programs for lowering bushfire risks, addressing legal obligations, and completing existing asset compliance-improvement programs
- **We have a flexible and efficient delivery strategy** – our delivery strategy ensures that we will efficiently minimise delivery costs through a balanced portfolio of internally and externally delivery mechanisms that allows us to ramp-up resources to deliver large projects and respond to customer needs
- **higher-powered incentives will drive efficient expenditure** – the amended service incentives will strengthen the penalty for not delivering service outcomes. It will also increase our incentive to efficiently minimise costs by increasing the likelihood that we will be rewarded for such efficiencies
- **the expenditure will be funded** – we have worked with the Department of Treasury, Department of Finance, Department of the Premier and Cabinet and the Office of Energy to increase the certainty that funds will be made available for the AA3 investment proposal

8.7 Corporate capital expenditure

In AA3, we will invest $301 million of capital in corporate services (see Table 49). This represents around 5% of total capital expenditure. The expenditure features in the regulatory categories on IT and business support[166]. Table 49 shows the forecast by regulatory category.

Table 49: Corporate capital expenditure

$ million real at 30 June 2012	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	% non-network
IT	44.4	43.0	26.9	29.2	30.3	173.8	57.7%
Business support	32.1	31.3	22.6	22.9	18.8	127.6	42.3%
Total corporate	**76.5**	**74.2**	**49.5**	**52.1**	**49.1**	**301.4**	**100.0%**

Approximately 58% of corporate expenditure is attributable to IT costs, with the remaining 42% attributable to business support capital expenditure. Business support capital expenditure includes investment in corporate real estate; property, plant and equipment, low value asset pool and East Perth Control Centre (see Figure 85).

[166] We allocate corporate capital expenditure between the transmission and distribution system in accordance with the method set out in the cost and revenue allocation methodology (Appendix E).

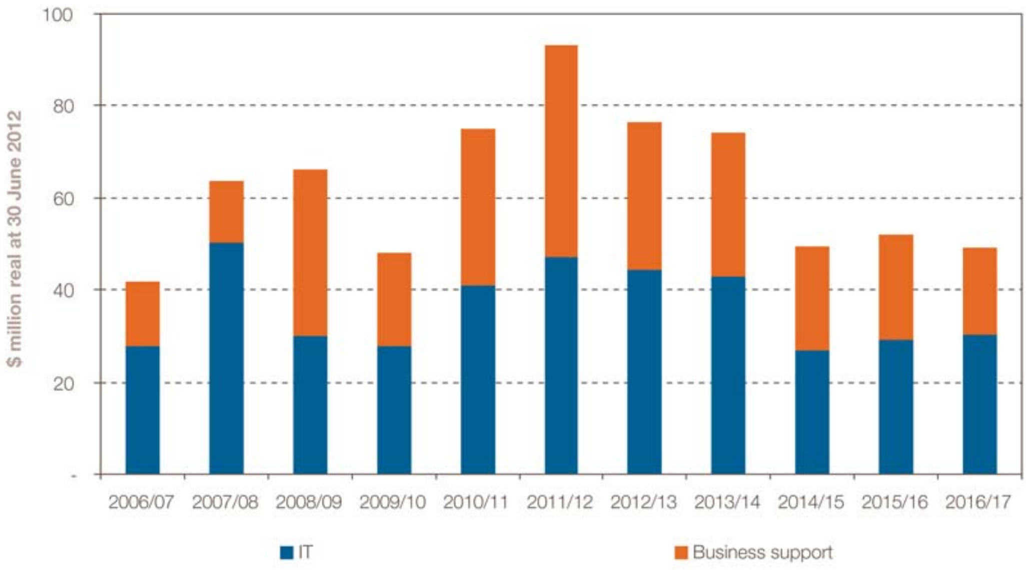

Figure 85: Corporate capital expenditure historical trend by regulatory category

The large increases in Business Support capital expenditure reflect the significant work underway to refurbish head office and depots. The major contribution to IT capital expenditure is the work underway to address our legacy IT systems through the Enterprise Systems program of work as outlined in the Enterprise Systems Asset Management Plan (ESAMP) provided in Appendix N.

We have forecast $174 million of IT capital expenditure over the AA3 period. The key drivers of this investment are the condition of existing IT assets and the need to meet and maintain current network standards.

The majority of this expenditure relates to the design, sourcing and execution of major enterprise systems transformation initiatives to improve our operations and improve the efficiency of our IT systems. The IT transformation journey commenced in AA2 and continues into AA3.

The remaining IT capital expenditure relates to:

- IT hardware and software asset replacement, capacity upgrades to meet organic growth and implementation of new technology to improve operations
- small enhancements to business systems

The business support capital expenditure covers the refurbishment and maintenance of office and depot accommodation and the purchase of property, plant and equipment. The expenditure increases during the 2010/11 to 2013/14 period due to the Vista project. This involves investment in refurbishing our head office and depot locations to comply with current building codes and remove asbestos and modernising our working environment. Expenditure in our other business support activities are relatively constant over time.

The investment proposed for AA3 is necessary to:

- ensure that we meet existing safety regulation and legislation[167]
- develop a bund facility[168] to reduce the environmental risk associated with the pressure on a transformer storage facility in Jandakot (which is currently located on a Priority 1 water mound)

8.8 Trend analysis

To assess the efficiency of our investment, we have compared our AA3 capital expenditure with historical trends. We have also benchmarked our capital investment against other Australian network businesses. The trend analysis is discussed in this section; benchmarking analysis can be found in section 8.9.

Figure 86 shows the total annual capital expenditure since 2006/07 by regulatory category. It illustrates:

- the lumpiness associated with large transmission capital works programs
- the impact of the global financial crisis, resulting in a decrease in growth related capital expenditure from 2008/09 to 2009/10
- the investment hiatus during the AA2 period resulting from project deferrals and a decrease in customer-driven work

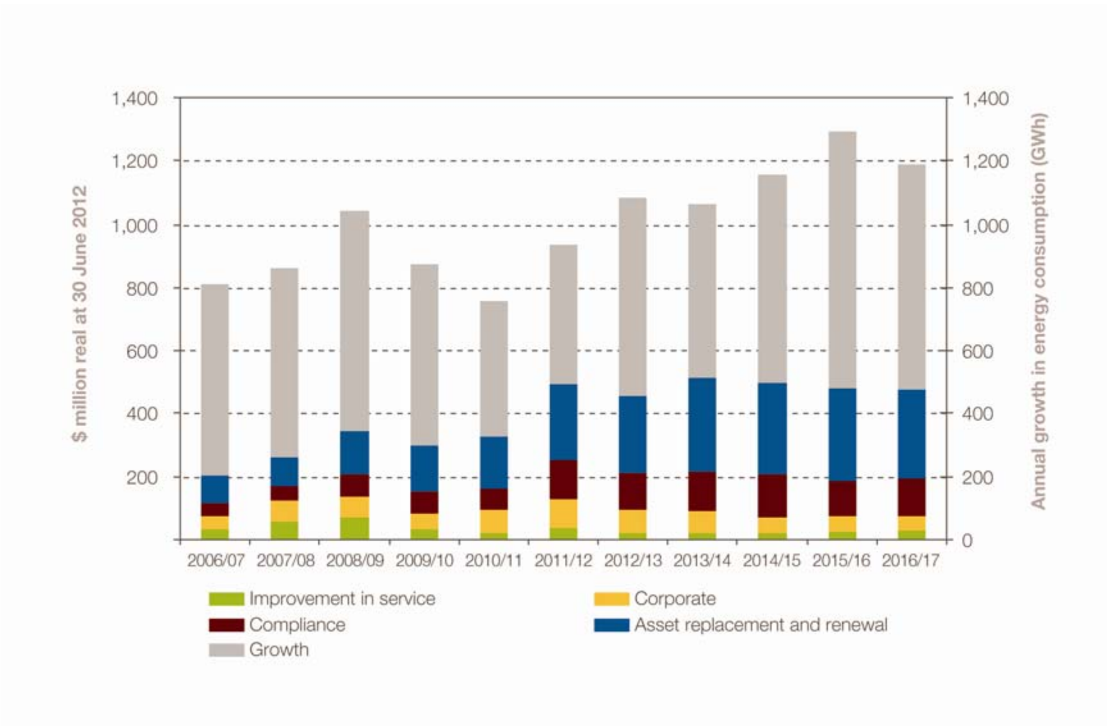

Figure 86: Total capital expenditure compared to history by regulatory category

[167] Including requirements set out in Australian building codes, the *Disability Discrimination Act 1992*, the *Operational Health and Safety Act 1984 (including NOHSC 2005 Code of Practice for Asbestos Removal)* and the *Environmental Protection Act 1986*.
[168] Bunds are designed to capture and contain oil leaks and spills to avoid environmental contamination.

Figure 86 illustrates that there is a step increase in capital expenditure for asset replacement and renewal and compliance from 2010/11 to 2011/12, and is then held relatively consistent during the AA3 period. The increase in asset replacement and renewal and compliance capital expenditure is largely due to an increase in the pole management program and bushfire mitigation activities and the replacement of 280,000 non-compliant meters.

Table 50 compares the growth rate in capital expenditure during the AA3 period with the growth rate in the five years prior to AA3. It also provides the growth rates in a number of drivers of capital expenditure for the same two periods. The growth rates in the number of distribution transformers and zone substation capacity are significantly higher for the AA3 period than the five year period prior to AA3, consistent with the increase in capital expenditure. This is due, in part, to the investment hiatus during the AA2 period.

Table 50: Comparison of capital expenditure growth with growth in activity drivers

Activity driver	Annual average growth rate in the five years prior to AA3	Annual average growth rate in the five year AA3 period
Customer numbers	2.5%	2.4%
Line length	1.4%	1.2%
Energy consumption	2.3%	2.7%
Number of distribution transformers	1.8%	3.0%
Zone substation capacity	4.9%	6.8%
Capital expenditure	2.9%	5.5%

8.9 Benchmarking capital expenditure

We have benchmarked our capital expenditure to our peers to indicate how it compares with other Australian network businesses. While benchmarking cannot be relied upon as the only source of data to inform decisions regarding investment, it can provide some guidance on average industry performance.

In making these comparisons with our peers, we note:

- that the definition of transmission and distribution varies from jurisdiction to jurisdiction and the nature of transmission and distribution businesses can vary significantly across jurisdictions. To ensure that our expenditure is more comparable with our peers, we have allocated some expenditure from transmission to distribution
- the difficulty of obtaining reliable publicly available information on which to undertake such benchmarking

In benchmarking the capital expenditure forecasts, we have:

- compared our historical capital expenditure for the transmission and distribution networks against other Australian network businesses on the basis of key network cost metrics for each network:
    - for transmission – peak demand and line length
    - for distribution – peak demand, line length and customer numbers

- compared our forecast capital expenditure for 2016/17 against the most recent publicly available actual data[169] using the same network cost metrics listed above in order to compare how our own costs move into the future. We note that comparisons of future cost to our peers' current costs are not meaningful because they do not account for any future cost movements that our network peers anticipate
- compared our historical and forecast capital expenditure against that which has been recently approved for other Australian network business in recent regulatory decisions (or submitted by the businesses where a decision is pending). Where enough forward looking data is available, this helps overcome the issue of accounting for our network peers' anticipated cost movements in our comparative analysis

Transmission capital investment

Our transmission net capital expenditure compares favourably with other transmission businesses on the basis of peak demand and line length, as shown in Figure 87 and Figure 88 respectively.

Figure 87 illustrates that the transmission capital expenditure as a function of peak demand is reasonably consistent with other transmission businesses and will become increasingly so over AA3 as our peak demand continues to increase.

The reduction in our capital expenditure as a function of peak demand between 2008/09 to 2016/17 shows that despite our major program of capacity expansion investment, peak demand will still outpace capital expenditure in 2016/17 relative to 2008/09.

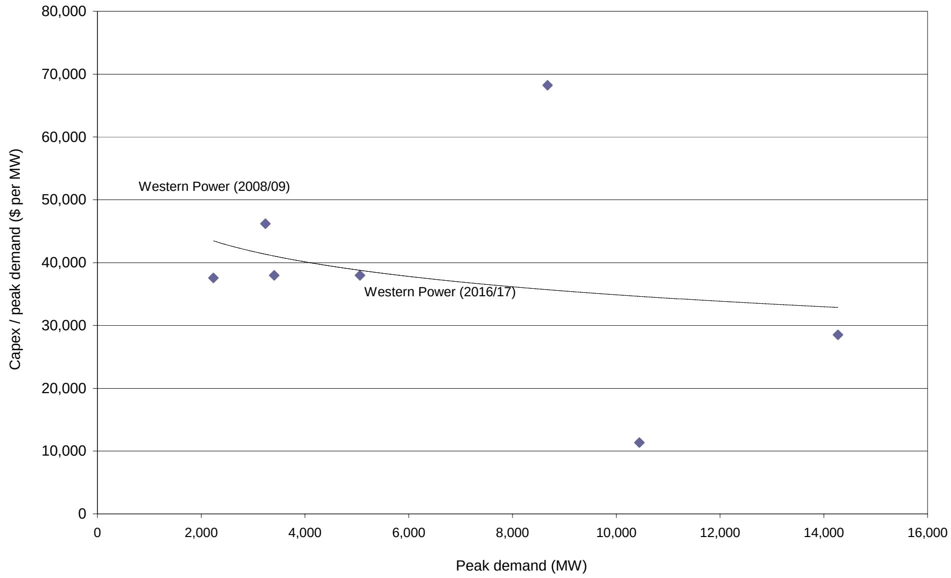

Figure 87: Comparison of transmission capital expenditure as a function of peak demand against peers, 2008/09

Figure 88 illustrates that the transmission net capital expenditure as a function of line length increases as line length increases.

[169] Actual data was not available for some distribution businesses in 2009/10. For these businesses, the data was estimated based on the best publicly available data.

The increase in our transmission net capital expenditure from 2008/09 to 2016/17 is greater than the growth in the line length from 2008/09 to 2016/17 due to our significant AA3 investment in capacity expansion and asset replacement. Hence our capital expenditure as a function of line length increases from 2008/09 to 2016/17, whilst remaining lower in 2016/17 than two of the businesses in 2008/09.

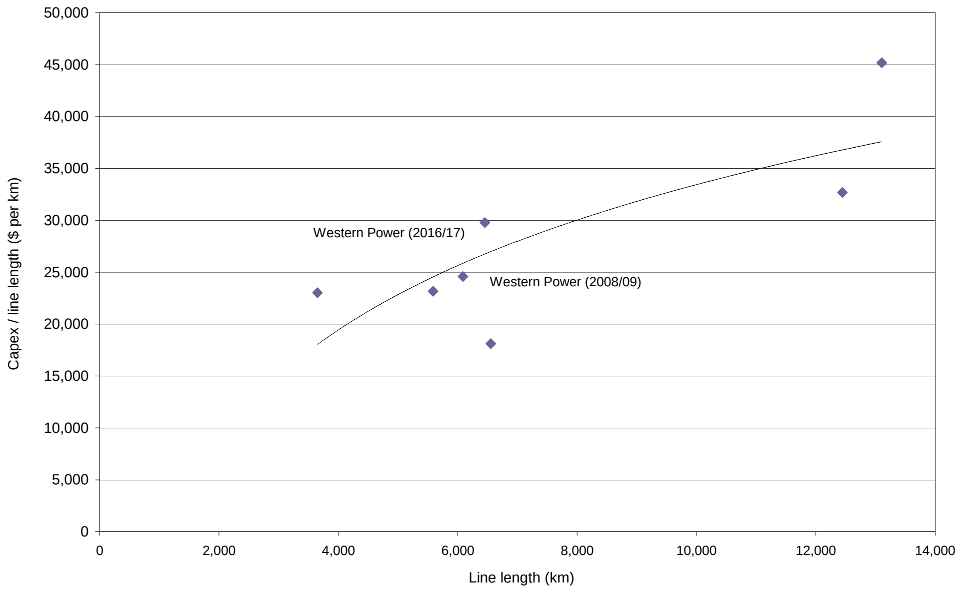

Figure 88: Comparison of our transmission capital expenditure as a function of line length against peers, 2008/09

We have also compared how our transmission net capital expenditure is forecast to increase over time relative to our peers as shown in. The forecast capital expenditure for all transmission businesses except Powerlink[170] is based on decisions that have been made by the relevant regulator.

Figure 89 illustrates that our forecast increase in transmission net capital expenditure is modest compared to the increases in capital expenditure accepted by the regulator for Transgrid and forecast by Powerlink. SP AusNet (Victoria), ElectraNet (South Australia) and Transend (Tasmania) are all expected to submit regulatory proposals for a period similar to AA3 within the next year, which may also propose similar increases.

Figure 89 also shows that the year-on-year variability in transmission capital expenditure that we experience is also experienced by the businesses in other jurisdictions due to the inherent lumpiness of transmission capital works projects.

[170] The forecast capital expenditure for Powerlink is based on its revenue submission to the AER.

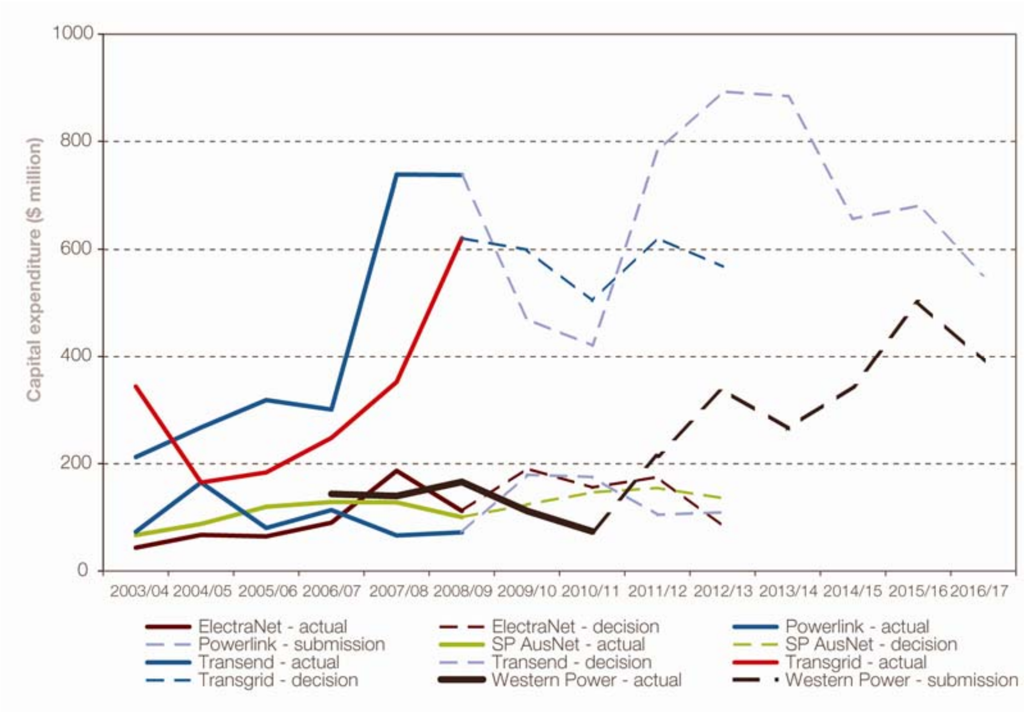

Figure 89: Comparison of historical and forecast transmission capital expenditure against peers

Distribution capital investment

Our distribution net capital investment compares favourably with the other distribution businesses, on the basis of the key drivers of capital investment: peak demand, line length and number of customers as shown in Figure 90, Figure 91 and Figure 92, respectively.

Figure 90 illustrates that the distribution net capital expenditure as a function of peak demand is reasonably consistent across all distribution businesses except Essential Energy (New South Wales) and Ergon Energy (Queensland), which have a higher capital expenditure to peak demand ratio than the other businesses. These two businesses both have large rural-based networks.[171]

The increase in our distribution net capital expenditure from 2009/10 to 2016/17 is similar to the growth in the peak demand in our network from 2009/10 to 2016/17 and hence the distribution net capital expenditure as a function of peak demand is relatively consistent between 2009/10 and 2016/17.

[171] Western Power has a large rural-based network as well as an urban network and can therefore be expected to have a higher ration that most Australian network businesses, but not quite as high as completely rural-based networks.

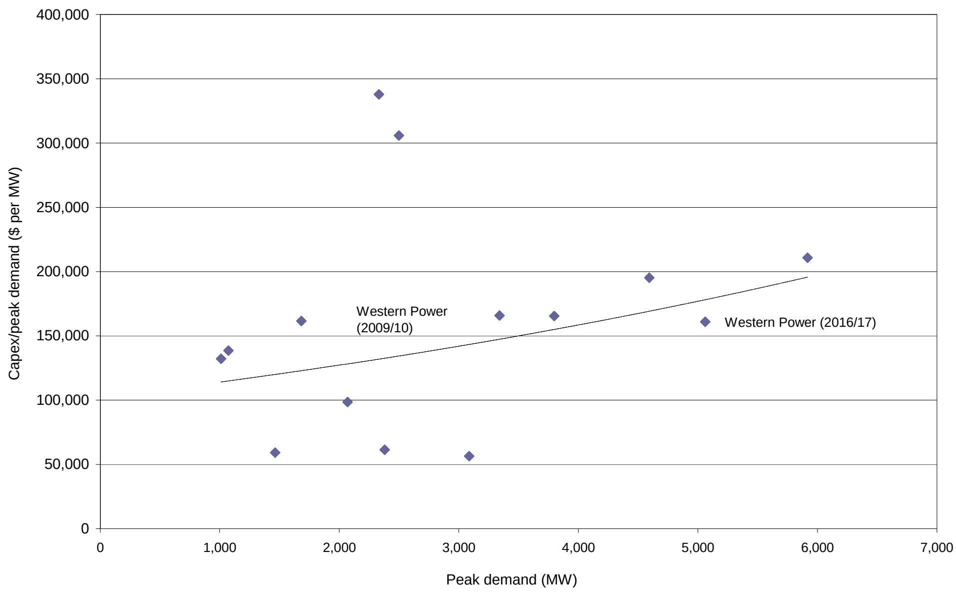

Figure 90: Comparison of distribution capital expenditure as a function of peak demand against peers, 2009/10

Figure 91 shows that the distribution capital expenditure as a function of line length decreases as line length increases.

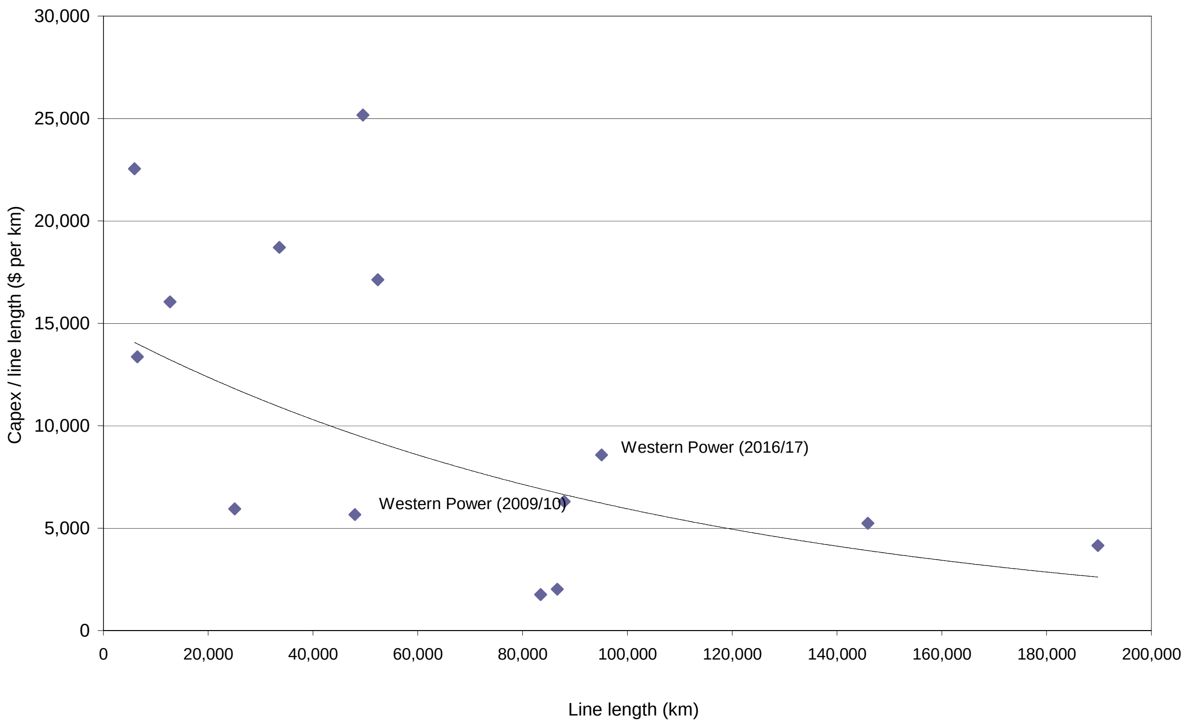

Figure 91: Comparison of distribution capital expenditure as a function of line length against peers, 2009/10

Our distribution net capital expenditure as a function of line length increases from 2009/10 to 2016/17. The capital expenditure between 2009/10 and 2016/17 is driven by factors other than line length. For example, replacing and reinforcing poles and replacing conductors under our substantial asset replacement and renewal program from AA3 will not result in an increase in line length. Despite the increase in the distribution net capital expenditure to line length ratio, the ratio continues to be reasonably consistent with the other distribution businesses.

Figure 92 shows that the net capital expenditure as a function of customer numbers for Australian distribution businesses lies broadly within a band between $200 per customer and $1,000 per customer. We compare favourably with the other distribution businesses in 2009/10.

Our distribution capital expenditure to customer numbers ratio increases from 2009/10 to 2016/17. However, the ratio continues to fall within the general band. The capital expenditure between 2009/10 and 2016/17 is driven by factors other than customer numbers. The need to replace and reinforce poles conductors is not driven by an increase in customer numbers.

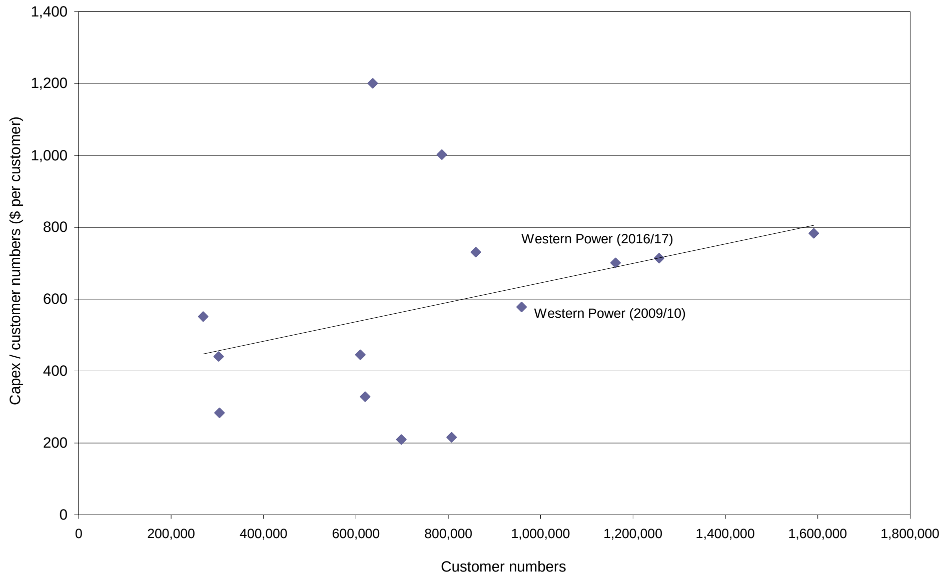

Figure 92: Comparison of distribution capital expenditure as a function of customer numbers against peers, 2009/10

We have also compared how our distribution net capital expenditure is forecast to increase over time relative to our peers as shown in Figure 93 and Figure 94. Figure 93 compares Western Power's forecast capital expenditure against the distribution businesses in Victoria, South Australia and Tasmania, and Figure 94 compares Western Power's forecast capital expenditure against the distribution businesses in New South Wales and Queensland. The forecast capital expenditure for all distribution businesses except Aurora[172] is based on decisions that have been made by the relevant regulator.

Consistent with our approach to comparing forecast distribution operating expenditure, we have illustrated the forecast distribution capital expenditure relative to the capital expenditure in 2009/10, which is given a value of 100.

Figure 93 shows that our forecast increase in distribution net capital expenditure over the AA3 period is less than ETSA Utilities (South Australia), CitiPower (Victoria) and Powercor (Victoria) but more than for United Energy (Victoria), Jemena (Victoria), SP AusNet and Aurora (Tasmania).

[172] The forecast capital expenditure for Aurora is based on a revenue submission to the AER.

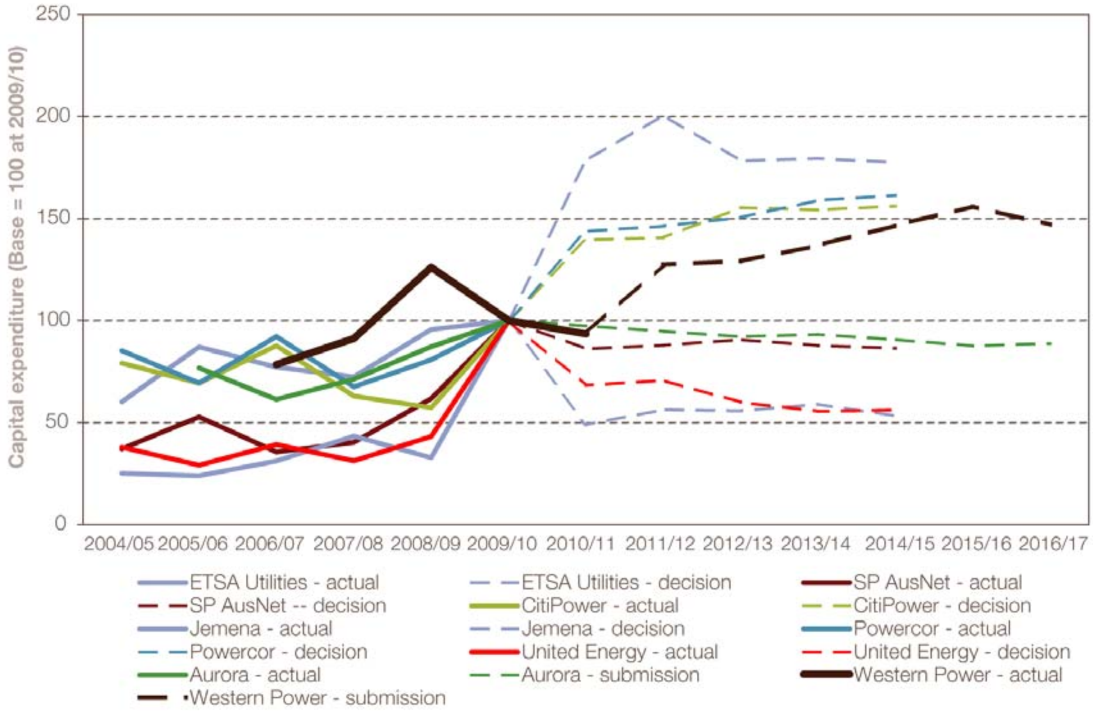

Figure 93: Comparison of forecast distribution capital expenditure against peers in Victoria, South Australia and Tasmania

Figure 94 shows that our forecast increase in distribution net capital expenditure over the AA3 period is less than for the Queensland electricity distributors, is consistent with Ausgrid (New South Wales) but more than for Endeavour Energy (New South Wales) and Essential Energy.

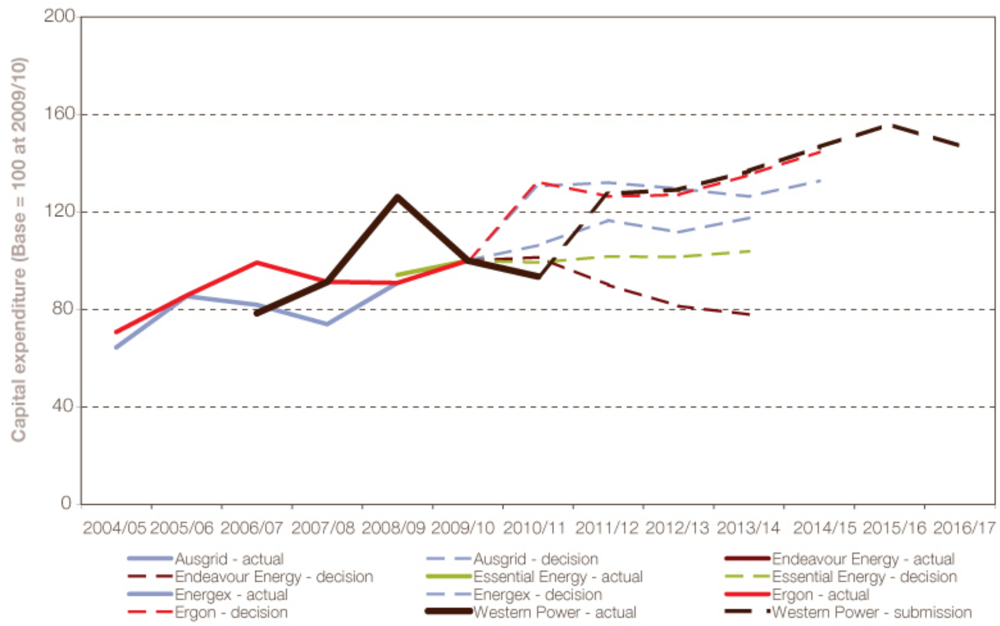

Figure 94: Comparison of forecast distribution capital expenditure against peers in New South Wales and Queensland

8.10 Capital expenditure items not yet included

There are a number of items that have emerged recently that are likely to have an impact on our future capital expenditure requirements. These items relate to the installation of metering at Verve generation sites, achieving compliance with existing noise regulations and proposed Energy*Safety* legislative changes. These have not been included in the AA3 forecasts to date, but are discussed below.

8.10.1 Interval metering at Verve generation sites

The Office of Energy is reviewing the suitability of the provisions of the Electricity Industry Metering Code 2005 (the Metering Code) to meet its objectives. In August 2011, the Office of Energy released a final recommendations report.[173] This report has been published on the Office of Energy's website[174] for information only and is not subject to public consultation. The recommendations in the report have been presented to the Minister for Energy for approval.

The report includes a recommendation that the Metering Code be amended so that generators who hold a generation licence will not be covered by clause 3.14:

> *Nothing in this Code requires a Code participant to upgrade, modify or replace a metering installation or any part of a metering installation which was commissioned before this clause 3.14 commenced.*

Generators would have until 30 June 2017 to ensure all the metering installations for their licensed generating plant currently covered by clause 3.14 are Metering Code compliant. This recommended change, which had not previously been considered in the April 2011 Recommendations report or April 2010 Issues Paper released by the Office of Energy, would require expenditure to be included in the AA3 submission to install interval meters of the accuracy required at all of Verve Energy's power stations. Subject to NFIT assessment, the costs to install the meters may require a capital contribution from Verve Energy.

We have not yet had an opportunity to fully cost the installation of the proposed Verve metering, and to consider the extent to which that cost should be recovered through reference tariffs and/or customer contributions. We anticipate costs to be more than $10 million. We expect that these costs and associated benefits will be subject to a regulatory impact assessment.

Should the changes be approved, we will use the relevant recovery provisions of the Access Code and access arrangement, which will allow costs to be passed through to customers in the AA4 period.[175]

8.10.2 Noise regulations

We are currently required to comply with the Environmental Protection (Noise) Regulations 1997 (WA). In June 2006, the Minister for Environment agreed to a variation under Regulation 17 of the Noise Regulations for our non-complying transmission substations. A works program was planned and agreed to bring all substations progressively into compliance by December 2019.

[173] *Amendments to the Electricity Industry Metering Code 2005; Final Recommendations Report*, Office of Energy, August 2011.
[174] http://www.energy.wa.gov.au
[175] If related to an unforeseen event under section 6.6 – 6.8 of the Access Code. However we will request recovery of the costs in this access arrangement revisions submission if the changes are approved before the conclusion of this access arrangement review process.

Progress against the agreed works program has been slow, primarily due to difficulty in identifying cost effective, workable technical solutions. In 2009, we estimated that the cost associated with achieving full compliance across the entire Western Power asset base including transformers, reclosers and emergency generators would be around $270 million. Priority has therefore been given to the most non-compliant substations.

To date $3 million has been spent completing noise mitigation at three substations, and a further $3.5 million is planned for works at a further five substations in AA2. Nine non-compliant substations will be addressed in the AA3 period with the remaining to be included in AA4.

The compliance implications for distribution assets were not fully appreciated at the time by either the Department of Environment and Conservation or Western Power. The first phase of the Regulation 17 approval expired on 31 December 2009. As a consequence 19 of the 34 transmission substations no longer have regulatory protection from non-compliance.[176] Negotiations with the Department over the past three years have failed to achieve an acceptable or workable outcome to address this issue. In light of the practical difficulties of achieving compliance in relation to distribution assets and the significant cost, we have not included the expenditure required for full compliance with Regulation 17 in our forecasts.

8.10.3 Clean Energy Future package

On 11 July 2011, the Commonwealth Government announced the introduction of the Clean Energy Future package which comprises a number of policy initiatives that have not yet been legislated including:

- a legislated carbon price of $23/t CO_2-e, increasing at a fixed rate above inflation for three years, and then transitioning to a cap-and-trade scheme linked to the international price
- promotion and investment of innovation in renewable energy
- support for energy markets to maintain security, while retiring 2000 MW of generation
- initiatives to encourage energy efficiency
- opportunities in the land sector to cut pollution and improve resilience

In the time available since the release of the Government's package, we have been unable to fully assess the implications of the carbon tax and broader policy initiatives for the AA3 period. However, our initial view is that:

- there is likely to be some increase in input costs from local products as a flow on from general increases in services and materials. The impact from overseas products is less certain. This may potentially affect both our capital and operating costs. However, we have not yet formed a view as to the magnitude of these costs
- there are likely to be reduced fuel tax credits from 2012/13. This is likely to potentially increase fuel costs and will affect our capital and operating costs. Our early assessment is that fuel cost increases would be less than $0.5 million per year
- the Biodiversity Fund may create cost or statutory barriers to purchasing land and biodiversity offsets. These may be covenants or other retention requirements, or needing to cover the additional costs associated with the purchased revegetated areas. Costs relating to land easements would impact our transmission capacity expansion portfolio. However, we have not formed a view as to the magnitude of

[176] In December 2009 Western Power requested an extension to Schedule 1 of the Regulation 17 Approval which was subsequently declined by the Minister for Environment.

these costs. The costs associated with purchasing land easements may increase as a result of the Biodiversity Fund. Given the limited details provided in the Government's package, we have not formed a view as to the magnitude of these costs. However, costs relating to land easements would impact our transmission capacity expansion portfolio

- the cost associated with transmission line projects (and hence our transmission capacity expansion and customer-driven portfolio) may increase as a result of the energy efficiency opportunities program. However, we have not formed a view as to the magnitude of these costs

We will continue to investigate these and provide supplementary forecasts to the Authority as soon as the legislation is passed and we have assessed the impact.

8.10.4 Energy*Safety* measures

Energy*Safety* advised Western Power in July and August 2011 of a number of proposed legislative changes as discussed in section 7.2.1. We have not yet had an opportunity to fully cost or assess the impact of the proposed changes. However, there may be associated capital costs arising from any required changes to work practices.

Should additional costs be incurred, we will use the relevant recovery provisions of the Access Code and access arrangement, which will allow costs to be passed through to customers in the AA4 period[177] or will trigger a reopening of the access arrangement[178].

8.11 Compliance with Access Code requirements

Western Power's capital expenditure forecasts must comply with a number of requirements under sections 2.8(e), and 6.49 to 6.52 of the Access Code.

When forming a view as to the whether the forecast capital expenditure meets the NFIT under section 6.52 of the Access Code, section 2.8(e) states that *a service provider must form that view as a reasonable and prudent person*. The capital expenditure forecasts have been developed to:

- reflect the network management plan and asset strategies which incorporate changes in obligations or good electricity industry practice from the previous regulatory period and are informed by recent asset performance and/or condition (see Appendix L: Network Management Plan)
- reflect the forecast cost of network augmentations sufficient to meet the forecast sales from the growth in load (demand), generation and customer numbers as detailed in the network development plan, where the assumptions underpinning these growth forecast parameters have been forecast or verified by independent experts (see chapter 6 of this document and Appendix S: SKM/MMA report – Review of WP's demand forecasts for the AA3 period)
- reflect an ongoing requirement to maintain covered services (the relevant obligations our provided in section 1.2 of this document and discussed throughout Appendix A: AA3 capital and operating expenditure report where relevant to particular regulatory categories)
- include forecast escalation in the market price of labour and materials using independent expert forecasts of these price movements (see Appendix W.1: CEG

[177] If related to an unforeseen event under section 6.6 – 6.8 of the Access Code or Technical Rule changes under section 6.9 – 6.12 of the Access Code.
[178] If related to a trigger event under section 4.37 of the Access Code.

report – Western Power escalation factors and Appendix W.2: Macromonitor report – Forecast of labour costs – electricity, gas, water and waste services sector)

- ensure the program of work will be delivered in an efficient manner under a balanced portfolio (see a summary of our delivery strategy in section 4.6 and Appendix M: Works Delivery Strategy)

A key requirement is the need for forecast capital expenditure to not exceed the amount that would be invested by a service provider efficiently minimising costs.[179] Our capital expenditure forecasts are consistent with this requirement because they:

- represent the least cost combination of asset management and development options as required by the network management and development plans through:
    - our planning, management and delivery system (see chapter 4 of this document)
    - recent initiatives to ensure optimisation and coordination of differing programs of work, such as the 'smart planning[180]' initiative and 'overlaps and dependencies' model[181] (see Chapter 3 of this document)
- incorporate unit costs that are consistent with current market rates as tested through our competitive tendering processes and procurement practices
- use building block estimates which are accurate and compare favourably with our peers (see section 8.3)
- compare favourably with our peers (see section 8.9)
- will be delivered in accordance with our delivery strategy that takes into account economies of scale or scope that can be achieved when packaging and scheduling the works (see Appendix M: Works Delivery Strategy)
- will be delivered on the basis of the lowest sustainable cost of providing the forecast covered services through a number of internal and external delivery mechanisms (see Appendix M: Works Delivery Strategy)

The AA3 capital expenditure forecasts are also consistent with the requirement that they be reasonably expected to satisfy the NFIT test in section 6.51A of the Access Code.

We routinely complete NFIT assessments as part of our business case development (see chapter 4 of this document). We apply planning processes to determine the need for network investment and the evaluation of options that address the NFIT criteria under section 6.52 of the Access Code with respect to efficiently minimising costs and the 'incremental revenue', 'net benefits' and 'provide covered services' tests under section 6.52 (b).

Table 51 identifies the relevant test under part (b) of the NFIT that applies to the majority of expenditure in each regulatory category.

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[179] Section 6.52(a), *Electricity Networks Access Code 2004*.
[180] The 'smart planning' initiative implemented in 2009/10 aims to reduce the number, frequency and cost associated with network outages by coordinating all work that requires isolation of a particular part of the network. During AA2, we applied smart planning to 12 substations coordinating replacement capital investment, planned maintenance work and protection testing activities.
[181] The 'overlaps and dependencies' model overlays expenditure forecasts in growth and asset replacement works by work type and activity to ensure there is no double counting of costs. It also assists planning efforts to identify works that can be combined to address different work drivers by asset or by geographic region.

Table 51: The NFIT part (b) test that applies in the majority of circumstances to each regulatory category of capital expenditure

AAI Guidelines category	Western Power's regulatory category	Most applicable NFIT Part b) test
Transmission		
Growth	Capacity expansion	Provide covered services
	Customer-driven	Incremental revenue
Asset replacement and renewal	Asset replacement	Provide covered services
Improvement in service	SCADA and communications	Provide covered services
Compliance	Regulatory compliance	Provide covered services
Distribution		
Growth	Capacity expansion	Provide covered services
	Customer access	Incremental revenue
	Gifted assets	Not applicable [182]
Asset replacement and renewal	Asset replacement	Provide covered services
	SUPP	Provide covered services [183]
	Metering	Provide covered services
	Smart grid	Net benefit
Improvement in service	SCADA and communications	Provide covered services
	Reliability driven	Provide covered services
Compliance	Regulatory compliance	Provide covered services
Corporate	IT	Provide covered services
	Business support	Provide covered services

Further details on how each regulatory category meets NFIT are provided in Appendix A: AA3 capital and operating expenditure report.

The majority of the forecast AA3 capital expenditure has not yet reached a stage where business cases have been approved or submitted to regulator (where applicable). However, we have developed forecasts for the AA3 period in accordance with requirements under the Access Code. Each activity has been tested to ensure it will be considered efficient in accordance with the Access Code objectives.

Under Chapter 9 of the Access Code, it is mandatory for Western Power to seek a regulatory test from the Authority for major augmentations on an ex-ante basis. The regulatory test is designed to apply specifically to 'major augmentations' where the value of the project exceeds the nominated threshold ($10.9 million for wholly distribution projects or $32.7 million if the project includes any transmission assets (CPI adjusted for 2011)).

We have received approval for the required regulatory test for one of the key projects included in the AA3 capital expenditure works program (the Mid-West Energy Project), and are currently awaiting pre-NFIT approval from the Authority. This project accounts for around $244 million or 4% of our AA3 capital expenditure.

[182] Gifted assets do not meet the new facilities investment test and are not added to the capital base.
[183] The full amount of expenditure does not meet the new facilities investment test; hence the test applies only to that portion of the state underground power program that Western Power invests in, approximately 25%.

A further nine transmission projects will require regulatory test approval during the AA3 period prior to committing to the major augmentation. These projects account for $434 million or 7% of the forecast AA3 capital expenditure.

8.12 Compliance with AAI Guidelines

Table 52 sets out where in this AAI and supporting appendices Western Power has provided information to demonstrate compliance with the AAI Guidelines requirements.

Table 52: AAI Guidelines compliance for capital expenditure

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.3.1	*Information supporting forecasts of costs must include:* • *the assumptions on which forecasts are based;* • *a full and detailed explanation of the basis of preparation of the forecasts; and* • *evidence to show the forecasts only include costs which would be incurred by a service provider efficiently minimising costs.*	Section 8.3
4.3.2	*The allocation of cost items must be based on the following principles.* • *Items that are directly attributable to a business component are allocated accordingly.* • *Items that are not directly attributable to a business component are to be allocated, where practicable, on a causation basis.* • *Items that are not directly attributable and cannot be practicably allocated on a causation basis must be allocated by a method determined by the service provider. In such cases, the access arrangement information must include a supporting note for each item thus allocated indicating:* – *the basis for allocation;* – *the reason for choosing that basis; and* – *an explanation for why no causal relationship could be established.* • *Consistency with previous years' allocation policies or, if not, any change to the allocation policy must be fully explained and prior year figures restated accordingly.*	Section 7.2 Appendix E: Cost and revenue allocation methodology 2010/11
4.4.1	*Forecasts of capital expenditure must be accompanied by, at least:* • *details of the methods used to develop the forecasts*	Section 8.3
4.4.1	• *the forecasts of load growth relied upon to derive the forecasts and details of the methods and assumptions used to develop the forecasts of capital expenditure from the forecasts of load growth*	Section 4.3, 6.2 and 8.2.1

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.4.1	• *a description of asset management plans relied upon to derive the forecasts of capital expenditure for the purposes of replacing assets and maintaining service levels; and details of the methods and assumptions used to develop the forecasts of capital expenditure in accordance with the asset management plans*	Section 4.4, 8.3, Appendix K: Network investment strategy, and Appendix L: Network Management Plan
4.4.1	• *a description of any regulatory obligations in service standards that have given rise to forecast capital expenditure and details of the methods and assumptions used to develop the forecasts of capital expenditure from the regulatory obligations*	Section 5.5 and 8.3
4.4.1	• *a description of any consideration of consumer preferences that have given rise to forecast capital expenditure and details of the methods and assumptions used to develop the forecasts of capital expenditure from consideration of the consumer preferences*	Appendix Y: KPMG Report – Customer preferences for supply reliability survey
4.4.1	• *quantification and an explanation of material variances in the forecast capital expenditure from historical levels of, and trends in, amounts of capital expenditure*	Section 8.8
4.4.1	• *justification and reasons of the service provider that the forecast capital expenditure is reasonably expected to meet the test for being added to the capital base under section 6.51A of the Access Code*	Section 8.11

PART C: TARGET REVENUE

9 Form of price control and method for calculating target revenue

This chapter provides information on the proposed form of price control for AA3 and the approach to calculating the target revenue for the AA3 period, including an overview of the building blocks methodology.

9.1 Key messages

- We will retain the structure of the AA2 form of price control for AA3, which includes a revenue cap for the services we provide to transmit and distribute electricity.
- For AA3 we clarify that the services we provide to transmit and distribute electricity fall within the revenue cap irrespective of whether they are provided as a reference service or a non-reference service.
- Consistent with AA2, we have applied the building blocks methodology to determine target revenue for AA3. This same methodology was used to determine target revenue for AA1 and AA2.
- We have implemented a number of changes to the assumptions in the revenue modelling for AA3. These changes better support the price control objectives[184], the Access Code objective and are consistent with practices from other regulatory decisions relating to Australian electricity utilities. These changes are:
    - changing the capital expenditure timing assumption from end-of-year to mid-year to better reflect the incidence of costs on Western Power[185]
    - including equity raising costs in revenue modelling for AA3 to reflect the need for a benchmark firm in Western Power's situation to raise additional equity to fund the investment program
    - including efficient regulated inventory assets in the capital base
    - including a revenue building block for the tax costs associated with capital contributions and gifted assets

[184] Section 6.4 of the Access Code
[185] Timing assumption relates to financial year, not calendar year.

Access Code provisions

Section 6.1

Subject to section 6.3, an access arrangement may contain any form of price control provided it meets the objectives set out in section 6.4 and otherwise complies with this Chapter 6.

Sectio 6.2

Without limiting the forms of price control that may be adopted, price control may set target revenue:

a) *by reference to the service provider's approved total costs; or*

   {Note: This includes "revenue cap" price controls based on controlling total revenue, average revenue or revenue yield and "price cap" price controls based on cost of service.}

b) *by setting tariffs with reference to:*

   i. *tariffs in previous access arrangement periods; and*

   ii. *changes to costs and productivity growth in the electricity industry;*

      {Note: This includes "price cap" price controls based on controlling the weighted average of tariffs or individual tariffs.}

      or

c) *using a combination of the methods described in sections 6.2(a) and 6.2(b).*

Price control objectives

Section 6.4

The price control in an access arrangement must have the objectives of:

a) *giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:*

   i. *an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;*

   plus:

   ii. *for access arrangements other than the first access arrangement, an amount in excess of the revenue referred to in section 6.4(a)(i), to the extent necessary to reward the service provider for efficiency gains and innovation beyond the efficiency and innovation benchmarks in a previous access arrangement;*

   plus:

   iii. *an amount (if any) determined under section 6.6;*

   plus:

   iv. *an amount (if any) determined under section 6.9;*

   plus:

   v. *an amount (if any) determined under an investment adjustment mechanism (see sections 6.13 to 6.18);*

   plus:

   vi. *an amount (if any) determined under a service standards adjustment mechanism (see sections 6.29 to 6.32);*

   plus —

   vii. *an amount (if any) determined under section 6.37A;*

   and

b) *enabling a user to predict the likely annual charges in target revenue during the access arrangement period; and*

c) *avoiding price shocks (that is, sudden material tariff adjustments between succeeding years).*

9.2 Proposed form of price control

We are retaining the revenue cap form of price control for the services that we provide to transmit and distribute electricity. We are retaining the charging criteria form of price control for ancillary services, such as high load escorts.

The revenue cap applies to all services that Western Power provides to transmit and distribute electricity, whether they are a reference or a non-reference service. The revenue cap also incorporates the associated metering services required under the Metering Code, such as a scheduled meter reading[186].

Non-reference services under the revenue cap are normally services that are similar to an existing reference service, but have been altered in some way at the request of the customer.

On average, these reference and non-reference services account for $2.066 billion of Western Power's revenue per year. In our revised access arrangement for the AA3 period we have defined these services as **revenue cap services**:

- **revenue cap services** means the following covered services we provide by means of the Western Power Network:
    - connection service
    - exit service
    - entry service
    - bi-directional service
    - the metering services provided ancillary to the services in paragraphs (a) to (d) that are defined as standard metering services in the most recent Model Service Level Agreement approved by the Authority under the Metering Code
    - streetlight maintenance

For services that are ancillary to services that transmit and distribute electricity, such as high load escorts, we have defined these as **non-revenue cap services** and their revenue falls outside of the revenue cap. Non-revenue cap services are always non-reference services and account for approximately $20 million of our revenue per year. In our access arrangement we have defined **non-revenue cap services** as follows:

- **non-revenue cap services** means non-reference services provided by Western Power by means of the Western Power Network other than revenue cap services

The form of price control for covered services having multiple parts is provided for in section 6.2(c) of the Access Code.

Figure 95 illustrates the proposed form of price control for AA3.

[186] Extended metering services under the Metering Code Model Service Level Agreement, such as de-energising a metering point, are considered to be non-revenue cap access services.

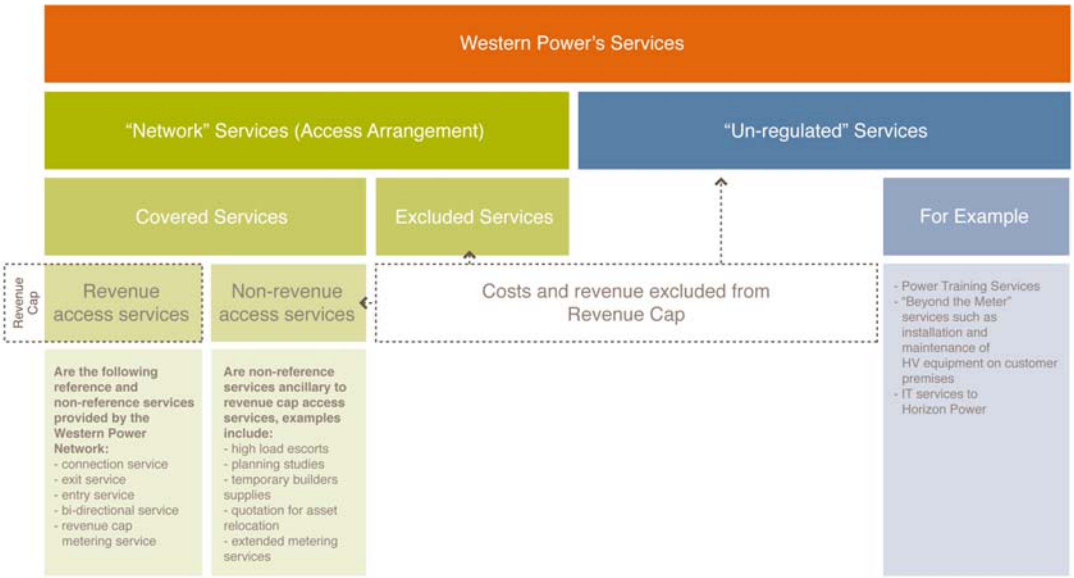

Figure 95: Form of price control for AA3

The form of price control for AA3 is detailed in chapter 5 of the proposed access arrangement, including the price control formulae required to calculate the transmission and distribution revenue caps for revenue cap services.

Our reasoning for adopting this form of price control in AA3 is described in the sections below.

9.2.1 Revenue cap for revenue cap services

There are three basic forms of price control:

1. **weighted average price cap** – a cap on a weighted average of the prices of a basket of services, rather than the revenue received from the services
2. **revenue cap** – a fixed revenue allowance for each year of the access arrangement period regardless of the output or services sold in any year
3. **revenue yield control** – a cap expressed in terms of output sold in any given year of the access arrangement period, usually kWh

Variations and hybrids of these basic forms of price control are adopted in a number of Australian jurisdictions:

- the majority of Australian electricity distributors are subject to a weighted average price cap form of control, except:
  - ActewAGL Electricity Distribution, which is currently subject to an average revenue yield form of price control
  - Energex, ErgonEnergy and Aurora Energy, which are subject to a revenue cap form of price control
- all electricity transmission companies that are regulated by the AER under the National Electricity Rules are subject to a revenue cap form of price control

There has been considerable discussion in the last decade about the merits of different forms of price control.[187] Each form has its relative strengths and weaknesses. Section 6.2(a) of the Access Code provides for a range of different forms of control to be adopted in our access arrangement.

For our transmission and distribution systems, we propose the following form of price control:

Transmission – we will retain the revenue cap for the transmission system into AA3 as it is the form of price control most suited to our transmission system. This is because the costs of the transmission system are generally driven by large and 'lumpy' capital expenditure projects. A revenue cap is the form of price control adopted by all other Australian electricity transmission network companies.[188]

Distribution – we will retain the revenue cap for the distribution system. We considered whether we should adopt a weighted average price cap or revenue yield form of price control for AA3. However, this would require significant improvements in our reporting of historical data on energy consumption and customer numbers. Required improvements to reporting would include:

- increased disaggregation of information by reference tariff
- analysis and adjustments to the historic data to ensure it is comparable and reliable

While disaggregated forecasts of energy consumption and customer numbers have been prepared for AA3, the detailed data required to produce these forecasts was not captured in earlier periods with the rigour that it is captured today. During AA3 we will continue to refine our forecasting approach to assess whether a weighted average price cap or revenue yield form of price control is more suitable for the customers of our distribution system in the AA4 period.

The revenue cap satisfies the price control objective described in section 6.4 of the Access Code. The revenue cap:

- provides Western Power the opportunity to earn revenue from the provision of revenue cap services
- specifies the revenue cap for each year of AA3 and therefore enables users to predict the likely annual changes in target revenue
- avoids price shock through the price path we have adopted which sets the revenue cap for each year (see section 13.3 of this document)

[187] A number of consultation papers and draft and final decisions published by the Victorian Essential Services Commission (and its predecessor, the Office of the Regulator-General), the Queensland Competition Authority and the Independent Pricing and Regulatory Tribunal of NSW, the AEMC 2006 review of chapter 6A of the National Electricity Rules and the MCE 2007 review of chapter 6 of the National Electricity Rules have addressed this issue in detail.
[188] Chapter 6A of the National Electricity Rules requires that electricity transmission companies adopt a revenue cap form of price control.

9.2.2 Non-revenue cap services

We will charge for non-revenue cap services based on charging criteria. The criteria used to set the tariffs and charges for these services are detailed in clause 5.1.2(b) of the proposed access arrangement, which ensures they are:

i. *negotiated in good faith;*
ii. *consistent with the Access Code objective; and*
iii. *reasonable*

This is consistent with sections 2.8(b) and 6.1 of the Access Code and is the same approach that was applied to non-reference services in AA2. The Authority is not required to approve tariffs or charges for non-revenue cap services as they are provided by non-reference services.

The associated forecast costs for providing these services are deducted from the 'building blocks' target revenue before calculating the annual revenue caps for revenue cap services.

This approach ensures costs and revenues are broadly matched and that service levels will also be closely aligned with each customer's requirements. Where possible, for commonly requested non-revenue cap services, we set standard fees and charges in line with the charging criteria and publish them on our website. For other non-revenue cap services we will negotiate individually with customers consistent with the charging criteria.

9.3 Use of 'building blocks' method

We have applied the building blocks method to determine target revenue and the revenue caps for AA3. This same method was used to determine target revenue over AA1 and AA2.

The building blocks method is commonly used by regulated businesses and economic regulators to determine the target revenue that meets the price control objective detailed in section 6.4(a) of the Access Code. It is also prescribed in the National Electricity Rules.[189]

We have determined the target revenue in each year of AA3 with reference to approved total costs, as provided for in section 6.2(a)[190] of the Access Code. Under the building blocks method the approved total costs are the building blocks, which when added together, determine our target revenue. Target revenue is determined separately for the transmission system and the distribution system.

We determine target revenue on a pre-tax basis, however, the building blocks for AA3 include tax costs incurred due to capital contributions and gifted assets. In a change from previous access arrangement periods, we propose that tax costs associated with capital contributions and gifted assets are collected during AA3 and are included explicitly in the calculation of target revenue. Further information on this revision can be found in section 12.6.

Figure 96 outlines the key building block elements, which when added together, determine our target revenue for AA3.

[189] Sections 6.3 and 6A.5.4 of the National Electricity Rules.
[190] Form of price control.

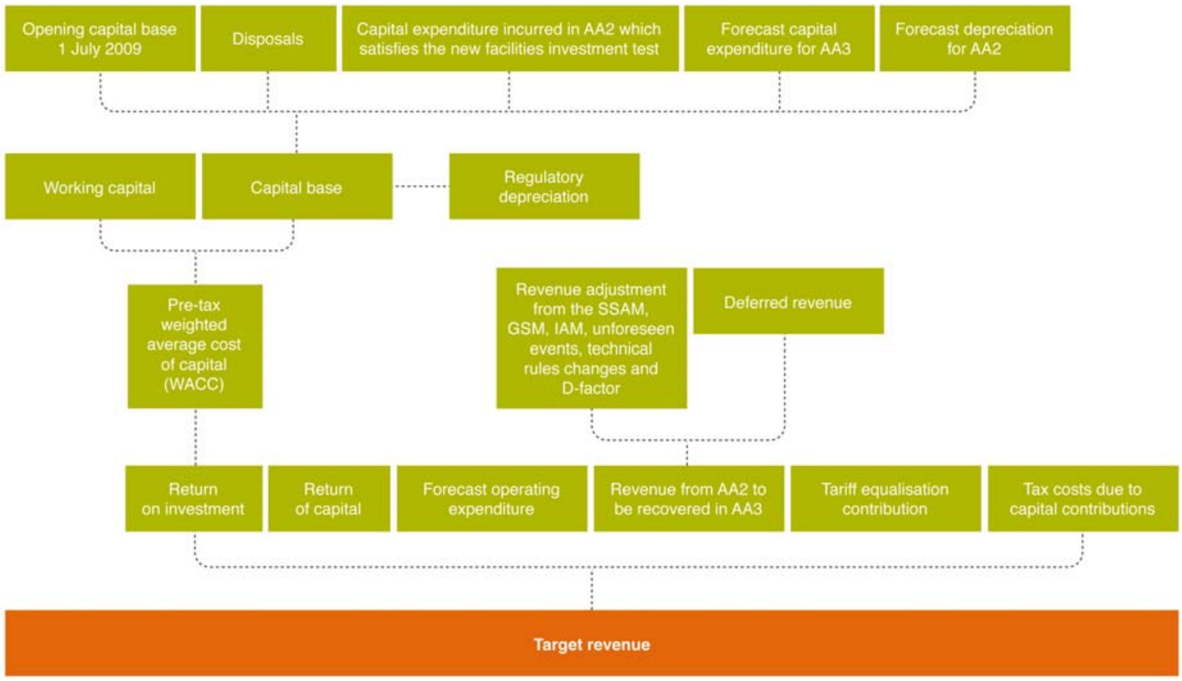

Figure 96: Revenue building blocks

Table 53 provides cross-references to other sections in this document that provide detailed information justifying each of the key building block elements shown in Figure 96.

Table 53: Cross reference as to where each of the revenue building blocks is discussed in this document

Revenue building block	Relevant section of this AAI document
Return on investment	Chapter 11
Forecast operating expenditure	Chapter 7
Return of capital	Section 10.3.3
Revenue from AA2 to be recovered in AA3	Section 12.2 and section 12.5
Tax costs due to capital contributions	Section 12.6

9.4 Revenue modelling

Our revenue model implements the building block method to determine the target revenue for the transmission system and distribution system. A copy of the revenue model calculations and outputs is provided in Appendix F: Revenue model summary.

The following formula is a simple representation of how the target revenue for providing covered services is calculated:

$$\mathbf{TR_t = r.RAB_{t,open} + Dep_t + O\&M_t + AA2_t + TEC_t + CCTax_t}$$

where:

TR_t = target revenue for providing covered services in year t.

r = WACC (in real pre-tax terms)

$RAB_{t,open}$ = opening value of the capital base (which takes into account forecast new facilities investment over the access arrangement period)

Dep_t = depreciation in year t (which takes into account forecast new facilities investment over the access arrangement period)

$O\&M_t$ = forecast of operating and maintenance costs for year t

$AA2_t$ = target revenue adjustment due to the SSAM, GSM, IAM, unforeseen events, Technical Rules changes, D-factor and deferred revenue for year t.

TEC_t = forecast of the tariff equalisation contribution for year t.

$CCTax_t$ = forecast of the tax costs resulting from capital contributions and gifted assets for year t.

The revenue model implements this calculation of the target revenue and incorporates the following high level assumptions:

- revenue modelling occurs on a real pre-tax basis[191]
- all expenses are modelled on an as-incurred basis
- end of year timing for modelling revenues and expenses in real terms. The exception to this general timing assumption is that when determining the opening value of the capital base and depreciation, new facilities investment is recognised mid-year and adjusted for a half-year return before being capitalised into the capital base (this exception is discussed further in section 10.2.6 of this document)
- separate modelling of the transmission system and distribution system

The calculation of our target revenue, which includes the forward-looking efficient costs, is set out in chapter 13 of this document.

[191] Except for the tax costs due to capital contributions and gifted assets. Refer to section 12.6.

10 Capital base

This chapter describes Western Power's method for rolling forward the capital base and calculating its closing value for AA2. It also includes forecasts of the capital base for each year of the AA3 period and considers:

- forecasts of new facilities investment
- forecasts of capital contributions
- inflation assumptions
- depreciation
- economic lives of assets
- calculation of opening capital base for AA4

Table 54 shows the forecast closing capital base values at 30 June 2012 (AA2) and at 30 June 2017 (AA3).

Table 54: Closing AA2 and AA3 capital base

Capital base	Forecast closing value for AA2 at 30 June 2012 ($ million real at 30 June 2012)	Forecast closing value for AA3 at 30 June 2017 ($ million real at 30 June 2012)
Transmission system	2,840.8	4,209.8
Distribution system	4,257.2	6,205.0
Total	7,098.0	10,414.8

10.1 Key messages

- We have established the capital base value as at 30 June 2012 using the same roll-forward method as in previous access arrangement periods.
- We will add $244 million ($ real as at 30 June 2012) of AA1 speculative investment that meets the requirements of the New Facilities Investment Test into the opening capital base for AA3.
- We roll forward the capital base over AA3 based on our forecast of new facilities investment and capital contributions. We use this capital base in determining our target revenue for AA3.
- We have adopted the straight-line depreciation method for the majority of investment, accelerating depreciation for distribution assets that are forecast to be decommissioned due to the State Underground Power Program (SUPP).
- We have made minor changes to the asset lives for some asset categories to better reflect the life of these assets for new facilities investment undertaken the AA3 period.
- No asset disposals are forecast over the AA3 period.

10.2 Establishing the opening capital base

We have forecast the opening capital base value using a roll-forward method consistent with section 6.48 of the Access Code.

The following sections detail the parameters used to derive the capital base value as at 1 July 2012.

Detailed calculations of the capital base over AA2 are included in the revenue model attached at Appendix F: Revenue model summary.

Access Code provisions

Section 6.48

For the start of each access arrangement period other than the first access arrangement period, the capital base for a covered network must be determined in a manner which is consistent with the Access Code objective.

> *{Note: A number of options are available in relation to the determination of the capital base at the start of an access arrangement period, including:*
>
> - *rolling forward the capital base from the previous access arrangement period applying benchmark indexation such as the consumer price index or an asset specific index, plus new facilities investment incurred during the previous access arrangement period, less depreciation and redundant capital etc; and*
> - *valuation or revaluation of the capital base using an appropriate methodology such as the Depreciated Optimised Replacement Cost or Optimised Deprival Value methodology.}*

10.2.1 Method used to roll forward the capital base

Consistent with the option outlined in section 6.48 of the Access Code we have determined the capital base at 1 July 2012 by:

- rolling forward the capital base value at the commencement of AA2 as set out in section 6.1 of our approved access arrangement for the period 1 July 2009 to 30 June 2012
- adding all new facilities investment incurred or forecast to be incurred[192] during AA2 that meets the requirements of section 6.51A of the Access Code[193]
- applying the consumer price index (weighted average of eight capital cities) to the rolled-forward capital base value
- deducting the depreciation forecast for the AA2 period, including the forecast accelerated depreciation
- deducting asset disposals based on the gross asset sales proceeds
- adding speculative investment incurred during AA1 that now meet the requirements of section 6.52 and 6.60 of the Access Code
- adding inventory assets to the opening capital base at 1 July 2012

We have not re-valued the capital base based on the depreciated optimised replacement cost or optimised deprival value method.

10.2.2 Compliance with the new facilities investment test

We are incorporating capital expenditure incurred during AA2 to the capital base in accordance with section 6.51A of the Access Code. We have assessed our AA2 capital expenditure against the new facilities investment test detailed in section 6.52 of the Access Code.

[192] The new facilties investment that is forecast to be incurred during 2011/12 has been used to determine the capital base. An adjustment for any variance between actual and forecast new facilities investment will be made in AA4, as discussed in section 10.2.10 of this document.

[193] We adopt a mid-year timing assumption for capital expenditure.

We have provided information in this AAI document to demonstrate why the Authority can conclude:

- that the processes and governance framework in place at the time the expenditure was incurred provides assurance that the new facilities investment has been assessed against the test under section 6.52 of the Access Code. Information to this effect includes:
    - a description of the processes and governance practices in place, as outlined in chapter 4 of this document
    - a description of improvements in processes and practices, as outlined in chapter 3 of this document and provided in additional detail in Appendix B.1: AA2 capital expenditure report.
- that the new facilities investment incurred satisfies the test under section 6.52 of the Access Code. Information to this effect includes:
    - the outcomes associated with these investments over the period, as outlined in chapter 3 of this document and provided in additional detail in Appendix B.1: AA2 capital expenditure report
    - the reasons for variances between what was assumed in the last review and the actual expenditure, as outlined in chapter 3 of this document and provided in additional detail in Appendix B.2: AA2 project and program list variance analysis
    - Appendix B.1: AA2 capital expenditure report provides additional supporting information as to why we believe actual and forecast capital expenditure over the AA2 period meets the requirements of the Access Code

10.2.3 Transmission capital base

This section details the parameters used to determine the closing capital base value at 30 June 2012.

Table 55 sets out the approved transmission capital base value at 30 June 2009.

Table 55: Approved transmission capital base value at 30 June 2009

Asset Group	Value ($ million real at 30 June 2012)
Transmission cables	27.9
Transmission steel towers	693.2
Transmission wood poles	220.4
Transmission metering	2.2
Transmission transformers	317.6
Transmission reactors	15.0
Transmission capacitors	148.6
Transmission circuit breakers	649.4
Transmission SCADA and communications	47.0
Transmission IT	24.2

Asset Group	Value ($ million real at 30 June 2012)
Other non-network assets	32.6
Land & easements	172.0
Total	**2,350.0**

The approved values reflect actual capital expenditure for 2008/9; therefore no adjustment for differences between forecast and actual expenditure in 2008/09 is required.

Table 56 lists the actual and forecast new facilities investment undertaken during AA2, which has been added to the capital base. Appendix B.1: AA2 capital expenditure report outlines how this new facilities investment meets the requirements of 6.51A of the Access Code.

Table 56: New facilities investment to be added to the transmission capital base

Asset Group	New facilities investment ($ million real at 30 June 2012)		
	2009/10	2010/11	2011/12 (Forecast)
Transmission cables	5.0	2.3	2.8
Transmission steel towers	59.6	35.2	46.4
Transmission wood poles	14.0	9.1	13.0
Transmission metering	0.0	0.0	0.0
Transmission transformers	35.7	18.3	25.0
Transmission reactors	1.2	0.4	0.3
Transmission capacitors	9.3	2.7	2.1
Transmission circuit breakers	47.8	34.3	40.8
Transmission SCADA and communications	10.5	6.5	14.7
Transmission IT	10.8	15.2	17.7
Transmission other non-network assets	7.7	12.7	17.3
Transmission land and easements	23.9	11.0	13.6
Transmission inventory	0.0	0.0	20.2
Total	**225.6**	**147.6**	**214.0**

Table 58 details the derivation of the new facilities investment (net of capital contributions and asset disposals).

Table 57: Derivation of the new facilities investment (net of capital contributions and asset disposals) to be added to the transmission capital base

Asset Group ($ million real as at 30 June 2012)	Year of expenditure		
	2009/10	2010/11	2011/12 (Forecast)
New facilities investment	225.6	147.6	214.0
Less asset disposals	6.0	0.3	0.0
Plus time value of money	8.6	5.8	7.6
Total new facilities investment (net of capital contributions and asset disposals)	**228.2**	**153.1**	**221.6**

Table 58 details the calculation of the transmission capital base value at 30 June 2012.

Table 58: Derivation of transmission capital base at 30 June 2012

($ million real as at 30 June 2012)	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening capital base value		2,350.0	2,502.9	2,575.5
Less depreciation		75.3	80.5	91.1
Less accelerated depreciation		0.0	0.0	0.0
Plus new facilities investment (net of capital contributions and asset disposals)		228.2	153.1	221.6
Plus investment from prior periods		-	-	135.0
Closing capital base value	**2,350.0**	**2,502.9**	**2,575.5**	**2,840.8**

10.2.4 Distribution capital base

This section details the parameters used to determine the closing capital base value at 30 June 2012.

Table 59 sets out the approved distribution capital base value at 30 June 2009.

Table 59: Approved distribution capital base value at 30 June 2009

Asset Group	Value ($ million real at 30 June 2012)
Distribution lines – wood poles	795.9
Distribution underground cables	1,158.0
Distribution transformers	388.1
Distribution switchgear	267.0
Street lighting	58.5
Distribution meters and services	170.6
Distribution IT	79.2
Distribution SCADA and communications	17.1
Distribution other, non-network	82.7

Asset Group	Value ($ million real at 30 June 2012)
Distribution land and easements	25.1
Total	**3,042.3**

The approved values reflect actual new facilities investment for 2008/09 therefore no adjustment for differences between forecast and actual new facilities investment in 2008/09 is required.

Table 60 lists the actual and forecast new facilities investment undertaken during AA2, which has been added to the capital base. Appendix B.2: AA2 project and program list and variance analysis shows how this new facilities investment meets the requirements of 6.51A of the Access Code.

Table 60: New facilities investment to be added to the distribution capital base

Asset Group	New facilities investment ($ million real at 30 June 2012)		
	2009/10	2010/11	2011/12 (Forecast)
Distribution lines – wood poles	148.3	142.4	203.2
Distribution lines – steel poles	0.0	0.0	0.0
Distribution underground cables	133.8	120.9	130.4
Distribution transformers	47.6	47.0	49.6
Distribution switchgear	50.1	50.0	62.6
Street lighting	14.3	14.6	16.1
Distribution meters and services	11.8	16.3	20.1
Distribution IT	17.1	25.7	29.4
Distribution SCADA and communications	3.6	3.4	4.3
Distribution other, non-network	12.3	21.4	28.9
Distribution land and easements	0.0	0.0	0.0
Distribution inventory	0.0	0.0	53.4
Total	**438.8**	**441.8**	**597.9**

Table 61 details the derivation of the new facilities investment (net of capital contributions and asset disposals).

Table 61: Derivation of the new facilities investment (net of capital contributions and asset disposals) to be added to the distribution capital base

Asset Group ($ million real as at 30 June 2012)	Year of expenditure		
	30 June 2010	30 June 2011	30 June 2012 (Forecast)
New facilities investment	438.8	441.8	597.9
Less asset disposals	0.9	0.0	0.0
Plus time value of money	17.1	17.3	21.3
Total new facilities investment (net of capital contributions and asset disposals)	**455.1**	**459.1**	**619.2**

Table 62 details the calculation of the distribution capital base value as at 30 June 2012.

Table 62: Derivation of distribution capital base as at 30 June 2012

($ million real at 30 June 2012)	30 June 2009	30 June 2010	30 June 2011	30 June 2012
Opening capital base value		3,042.3	3,338.4	3,625.2
Less depreciation		154.7	168.2	186.0
Less accelerated depreciation		4.2	4.1	4.0
Plus new facilities investment (net of capital contributions and asset disposals)		455.1	459.1	619.2
Plus investment from prior periods	-	-	-	202.8
Closing capital base value	**3,042.3**	**3,338.4**	**3,625.2**	**4,257.2**

10.2.5 Inflation values

Consistent with the approach in AA2, we have applied the consumer price index (weighted average of eight capital cities) to determine the rolled-forward capital base value.

Table 63 shows the inflation values applied when determining the rolled-forward capital base value to 30 June 2012.

Table 63: Inflation values applied when determining 30 June 2012 capital base

Financial year ending:	30 June 2009	30 June 2010	30 June 2011	30 June 2012 (forecast)
June CPI	167.0	172.1	178.3	
Inflation	1.46%	3.05%	3.60%	2.50%

The inflation values use actual CPI data published by the Australian Bureau of Statistics for the June quarter[194] where available. Where Australian Bureau of Statistics data is not available, we have used forecast CPI data from the Reserve Bank of Australia's Statement on Monetary Policy.

10.2.6 New facilities investment timing assumption

We have adopted a mid-year timing assumption for new facilities investment when establishing the opening capital base at 1 July 2012. Mid-year timing is appropriate to simulate the impact of incurring new facilities investment throughout the year. It reflects the forward-looking efficient costs of providing covered services and is also consistent with the timing of our 'summer ready' program which requires a significant portion of our investment program to be completed by December each year. Mid-year timing is also adopted by the AER for other Australian regulated utilities in its roll-forward model and post-tax revenue model.[195]

To align the mid-year timing assumption for new facilities investment with the target revenue end-of-year cash flow timing assumption, the new facilities investment added to the capital base must be adjusted to an end-of-year cash flow. This has the effect of capitalising the first six months of costs and provides for them to be recovered over the life of the assets. This is achieved by adjusting the new facilities investment for the time value of money for six months by applying the following factor to new facilities investment:

$$(1+WACC_{\text{real pre-tax}})^{½}$$

The adjusted new facilities investment will be depreciated commencing in the next year, consistent with the addition to the capital base reflecting an end of year timing assumption.

10.2.7 Speculative investment from AA1

We will add $244.43 million ($ real as at 30 June 2012)[196] of AA1 speculative investment that meets the requirements of the new facilities investment test (NFIT) into the opening capital base for AA3. This investment from AA1 has been added to the AA3 opening capital base in accordance with sections 6.58 – 6.60 of the Access Code.

Our opening capital base at 1 July 2010 reflected a lower level of new facilities investment than actually occurred in AA1. The capital base was reduced by $261.09 million ($ real as at 30 June 2009). A review of documentation of specific projects and programs with investment in both the AA1 and AA2 periods has shown that the NFIT is satisfied for those projects and programs and, by extension, for the amount of $223.4 million ($ real as at 30 June 2009) satisfies NFIT.

[194] Australian Bureau of Statistics, 6401.0 - Consumer Price Index, TABLES 3 and 4. CPI: Groups, Weighted Average of Eight Capital Cities, Index Numbers and Percentage Changes, Series Id: A2325846C, available from:http://www.abs.gov.au
[195] AER electricity distribution guidelines and electricity transmission guidelines, http://www.aer.gov.au.
[196] $223.35 million $ real at 30 June 2009.

Access Code provisions

Section 6.58

The "speculative investment amount" (if any) for a new facility at any time is equal to:

a) the new facilities investment;

minus:

b) any recoverable portion;

minus:

c) any amount for which a contribution has been, or is to be, provided to the service provider;

minus:

d) any part of the speculative investment amount for the new facility previously added to the capital base under section 6.60.

Section 6.59

If the calculation in section 6.58 produces a negative result, the speculative investment amount is zero.

Section 6.60

If:

a) a speculative investment amount was created for a new facility at a time; and

b) a determination is being made under section 6.44 at a later time,

then any part of the speculative investment amount which satisfies the new facilities investment test at the later time may be added to the capital base.

Our opening capital base at 1 July 2010 was reduced to reflect a lower level of new facilities investment than had actually been undertaken for AA1. Specifically, the capital base was reduced for AA1 new facilities investment by $261.09 million ($ real as at 30 June 2009), which was equivalent to 10.5% of total AA1 new facilities investment.[197]

The adjustments reflected:

- $23.24 million (in 30 June 2009 dollars) for a number of specific transmission projects on the basis that these had been delayed or did not proceed, or should have been recovered through capital contributions. These specifically related to:
    - the North Country region 330 kV transmission project (also known as the Mid West Energy Project) ($9.87 million ($ real as at 30 June 2009))
    - the Newgen Neerabup power station ($3.25 million ($ real as at 30 June 2009))
    - a portion of the cost of the 490 MVA Wells terminal station transformer to connect the Boddington Gold Mine ($3.15 million ($ real as at 30 June 2009))
    - the Busselton to Margaret River transmission line project ($6.97 million ($ real as at 30 June 2009))
- $126.87 million ($ real as at 30 June 2009) of inefficiencies arising from deficiencies in processes of cost estimation and from overcharging by contractors[198]
- $110.97 million ($ real as at 30 June 2009), representing five per cent of new facilities investment net of the adjustments above and gifted assets, that

[197] Paragraph 744, *Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network*, ERA, 4 December 2009.
[198] Paragraph 743, Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, ERA, 4 December 2009.

inefficiencies have occurred in the selection and timing of augmentation projects as a result of deficiencies in methods for forecasting demand for network services and deficiencies in analysis of options for augmentation projects[199]

The latter two adjustments were based on a review of identified projects or programs in relation to the following:

- $10.12 million ($ real as at 30 June 2009) of project specific costs reflecting the costs associated with the Wells terminal station transformers to connect Boddington Gold mine and the Busselton to Margaret River Transmission line project
- $18.4 million ($ real as at 30 June 2009) of inefficiencies associated with inadequate cost estimation across a number of specifically identified projects
- $9.2 million ($ real as at 30 June 2009) identified overcharging by contractors on a number of reviewed arrangements

These adjustments related to specific projects did not, and continue not, to pass NFIT and should not be added to the capital base.

The remaining $223.4 million ($ real as at 30 June 2009) of investment incurred in AA1 was disallowed on the basis of the extrapolation of specific findings to the whole investment. We have adopted a similar approach to the speculative investment amount.

Our review of certain projects and programs has identified documentation that demonstrates that NFIT is satisfied for those projects and programs. Using a similar approach to that adopted by the Authority, we extrapolate those findings to establish that the full amount of disallowed expenditure that does not relate to the abovementioned identified projects satisfies NFIT.

Further information supporting our addition of speculative investment to our capital base is provided in Appendix C: AA1 new facilities investment.

[199] Paragraph 743, Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, ERA, 4 December 2009.

Table 64 shows the speculative investment from the AA1 period that is to be added to the opening capital base for AA3.

Table 64: Speculative investment to be added to the AA3 opening capital base

	2006/07	2007/08	2008/09	AA1 total
$ million real at 30 June 2009				
Distribution speculative investment that satisfies NFIT	27.8	28.8	32.4	134.4
Transmission speculative investment that satisfies NFIT	37.1	42.2	55.1	89.0
$ million real at 30 June 2012				
Distribution speculative investment that satisfies NFIT	40.6	46.2	60.2	147.1
Transmission speculative investment that satisfies NFIT	30.4	31.5	35.5	97.4
Total to be added to the capital base	**71.0**	**77.7**	**95.7**	**244.4**

Before being added to the opening capital base on 1 July 2012 these values are adjusted to account for the time value of money and equivalent, in net present value terms, to the AA1 written down capital expenditure of $223.4 million ($ million at 30 June 2009).

10.2.8 Equity raising costs

We have not included equity raising costs in our opening capital base at 1 July 2012. However equity raising costs can be sensitive to our modelling assumptions and parameters, particularly the recovery period of deferred revenue. In the event that any of these assumptions are varied it is likely that the equity raising costs will need to be included in the capital base for AA3.

Section 6.4(a)(i) of the Access Code provides for target revenue to include forward-looking and efficient costs of providing covered services. We consider that this includes equity raising costs.

We have applied the method for cash flow modelling used by the AER in its recent *Final Decision for Victorian Distributors (2010)*[200] to calculate whether equity raising costs are required for AA3.

Equity raising costs can be classed into two categories: indirect and direct. Direct costs include underwriting, management fees and out of pocket expenses. Indirect costs can include underpricing, where the new equity security is sold at a discount to current market prices. We consider that only direct equity raising costs are relevant to calculating target revenue.

In our modelling, 30% of dividends are assumed to be returned to the business through a dividend reinvestment plan at a cost of 1%. Any further requirement for equity is assumed to come from seasoned equity offerings at a cost of 3%. These assumptions are consistent with the AER's methodology. In keeping with the Australian Competition Tribunal's April 2011

[200] *Final Decision - Victorian electricity distribution network service providers distribution determination 2011–2015*, AER, October 2010, available from: http://www.aer.gov.au/content/index.phtml/itemId/740791

Decision[201] on the value of imputation credits, a distribution rate of 70% is assumed for imputation credits.

We have determined that no equity raising costs would be incurred on the basis of these proposed revisions.

10.2.9 Inventory

We have included $74 million of inventory assets in the opening capital base at 1 July 2012 to recover the financing costs associated with efficiently holding these assets from users of covered services. Section 6.4(a)(i) of the Access Code provides for target revenue to include forward-looking and efficient costs of providing covered services, which includes the cost of holding inventory.

During AA1 and AA2 these costs were recovered from unregulated services. We propose this issue be addressed in AA3 to ensure that users of unregulated services do not subsidise users of covered services.

We are not seeking to recover costs incurred during AA1 and AA2 from covered services retrospectively.

Further information on our approach is provided in Appendix D: Justification for recovery of regulated inventory costs.

An efficient level of inventory holdings has been allocated between transmission, distribution and unregulated categories. These have then been added as a one-off addition to the capital base at 1 July 2012 consistent with the allocation. Annual capital base adjustments reflecting the stock of inventory are then made to increase and decrease the inventory capital base value. Table 65 details the annual inventory holdings:

Table 65: Inventory holdings closing value

($ million real as at 30 June 2012)	30 June 2012	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Distribution	53.4	53.9	56.3	58.6	57.5	59.9
Transmission	20.2	20.6	29.6	33.2	31.5	31.8
Total	73.6	74.5	85.9	91.8	89.0	91.8

We have not incorporated a depreciation allowance on regulated inventory assets because an asset is assumed to not commence its useful life until it goes into service.

10.2.10 Adjusting for variation from 2011/12 forecasts

Actual new facilities investment and inflation for 2011/12 was not available at the time of writing this proposal. Therefore the opening capital base has been calculated using forecast new facilities investment and inflation for 2011/12.

To ensure Western Power and customers are held economically neutral in the event of a variation between forecast and actual new facilities investment and inflation, we propose that the capital base at the commencement of the next access arrangement period (AA4) be adjusted to correct for this variation.

[201] *Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011)*, Australian Competition Tribunal, available from: http://www.austlii.edu.au/au/cases/cth/ACompT/2011/9.html

An adjustment will also be made to the target revenue for AA4 to compensate Western Power (or customers) for any revenue foregone (or additional revenue recovered) as a result of a variation from forecast in 2011/12.

The target revenue for AA3 will not be adjusted for any differences between the 2011/12 forecast and actual new facilities investment or inflation.

10.3 Capital base value over AA3

Consistent with section 6.51 of the Access Code, forecast capital investment that is reasonably expected to satisfy the new facilities investment test is included in our calculation of the capital base at the end of the AA3 period (30 June 2017).

Forecast closing values at 30 June 2017 ($ million real at 30 June 2012) are:

- transmission system capital base = **$4,209.8**
- distribution system capital base = **$6,205.0**

The following sections show the parameters used to derive the capital base value at 30 June 2017 consistent with the AAI Guidelines. The revenue model attached in Appendix F: Revenue model summary includes the detailed calculations of the capital base over AA3.

Access Code provisions

6.51 *For the purposes of section 6.4(a)(i) and subject to section 6.49, the forward-looking and efficient costs of providing covered services may include costs in relation to forecast new facilities investment for the access arrangement period which at the time of inclusion is reasonably expected to satisfy the test in section 6.51A when the forecast new facilities investment is forecast to be made.*

Section 6.51A of the Access Code details the test for adding new facilities investment to the capital base:

6.51A *A new facilities investment may be added to the capital base if:*

a) it satisfies the new facilities investment test; or

b) the Authority otherwise approves it being adding to the capital base if:

i. it has been, or is expected to be, the subject of a contribution; and

ii. it meets the requirements of section 6.52(a); and

iii. the access arrangement contains a mechanism designed to ensure that there is no double recovery of costs as a result of the addition.

When rolling forward the capital base over the AA3 period we adopted a mid-year timing assumption for new facilities investment in determining the net new facilities investment to be added to the capital base.

Net new facilities investment is determined for each year as follows:

$$\textbf{Net new facilities investment}_t = \textbf{(Forecast new facilities investment}_t - \textbf{forecast contributions}_t\textbf{)} * \textbf{(1+WACC}_{\text{real pre-tax}}\textbf{)}^{½}$$

Forecast contributions from customers are discussed in detail in chapter 8 of this document.

10.3.1 Transmission capital base

Table 66 provides an overview of the forecast transmission capital base values for each year of AA3.

Table 66: Assessment of transmission capital base

($ million real at 30 June 2012)	30 June 2012	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Opening capital base value		2,840.8	3,102.2	3,277.1	3,526.2	3,931.8
Less depreciation		91.2	100.9	109.2	117.8	129.6

($ million real at 30 June 2012)	30 June 2012	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Less accelerated depreciation		0.0	0.0	0.0	0.0	0.0
Plus new facilities investment (net of capital contributions)		352.5	275.9	358.3	523.4	407.6
Less asset disposals		0.0	0.0	0.0	0.0	0.0
Closing capital base value	**2,840.8**	**3,102.2**	**3,277.1**	**3,526.2**	**3,931.8**	**4,209.8**

Table 67 details the derivation of forecast net transmission new facilities investment for each year of AA3.

Table 67: Transmission new facilities investment[202]

($ million real at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17
Forecast new facilities investment	379.4	306.7	386.1	544.8	435.5
Less forecast contributions	41.4	41.8	42.5	43.1	44.7
Plus time value of money adjustment	14.6	11.0	14.7	21.7	16.9
New facilities investment added to the capital base	**352.5**	**275.9**	**358.3**	**523.4**	**407.6**

10.3.2 Distribution capital base

Table 68 below provides an overview of the forecast distribution capital base values for each year of AA3.

Table 68: Assessment of distribution capital base

($ million real at 30 June 2012)	30 June 2012	30 June 2013	30 June 2014	30 June 2015	30 June 2016	30 June 2017
Opening capital base value		4,257.2	4,614.4	5,037.7	5,452.5	5,832.5
Less depreciation		206.7	226.9	250.8	255.7	270.2
Less accelerated depreciation		3.4	0.5	0.0	0.0	0.0
Plus new facilities investment (net of capital contributions)		567.4	650.7	665.6	635.6	642.7
Less asset disposals		0.0	0.0	0.0	0.0	0.0
Closing capital base value	**4,257.2**	**4,614.4**	**5,037.7**	**5,452.5**	**5,832.5**	**6,205.0**

Table 69 details the derivation of forecast net distribution new facilities investment for each year of AA3.

[202] We allocate our corporate capital expenditure between the transmission system and distribution system in accordance with the method set out in the cost and revenue allocation methodology attached at Appendix E.

Table 69: Distribution new facilities investment[203]

($ million real at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17
Forecast new facilities investment	646.2	711.2	714.2	686.5	696.1
Less forecast contributions	102.1	87.3	76.1	77.2	79.9
Plus time value of money adjustment	23.5	26.8	27.4	26.4	26.5
New facilities investment added to the capital base	**567.4**	**650.7**	**665.6**	**635.6**	**642.7**

10.3.3 Depreciation

Consistent with AA1 and AA2, we have used the straight-line approach to determine depreciation[204] over the life of the asset. Also consistent with AA2, we have accelerated depreciation for distribution assets that are scheduled to be decommissioned as a result of the State Underground Power Program.[205]

When calculating depreciation we have retained the economic lives that were applied in AA1 and AA2 except for ‘Transmission SCADA and communications’, ‘Transmission IT’ and ‘Distribution IT’.

This is because we found that the values used for these asset groups in AA1 and AA2 were not consistent with the economic lives applied in other jurisdictions and the assumptions now adopted by Western Power for accounting purposes. [206]

The revised economic lives for these assets are highlighted in Table 70 and Table 71. Note that these changes will only affect the calculation of the capital base and target revenue for new facilities investment undertaken during the AA3 period. New facilities investment undertaken in AA1 and AA2 will continue to be depreciated based on the economic lives that applied at the time the depreciation forecast was developed for the investment.

Table 70: Transmission asset groupings and economic lives for depreciation purposes

Asset group	Economic life (years) for depreciation purposes
Transmission transformers	50 years
Transmission reactors	50 years
Transmission capacitors	40 years
Transmission circuit breakers	50 years
Transmission lines – steel towers	60 years

[203] We allocate our corporate capital expenditure between the transmission system and distribution system in accordance with the method set out in the cost and revenue allocation methodology attached at Appendix E.
[204] The depreciation component of the calculation of target revenue as provided for in section 6.2(a) of the Access Code, will differ from the depreciation charge that appears in the statutory financial accounts, or in Western Power’s tax return due to different asset lives adopted and different valuation methods of the capital base values.
[205] Refer to Part C section 5.3, *Access Arrangement Information Document for the first regulatory period 1 July 2006 to 30 June 2009*, Western Power, and *Part C section 5.3*, *Access Arrangement Information Document for the second regulatory period 1 July 2009 to 30 June 2012,* Western Power.
[206] The former economic lives for Transmission SCADA, Transmission IT and Distribution IT were 34.15, 16.85 and 10.16 years respectively.

Asset group	Economic life (years) for depreciation purposes
Transmission lines – wood poles	45 years
Transmission cables	55 years
Transmission metering	40 years
Transmission SCADA and communications	**11 years**
Transmission IT	**6 years**
Transmission other, non-network assets	16.85 years

Table 71: Distribution asset groupings and economic lives for depreciation purposes

Asset group	Economic life (years) for depreciation purposes
Distribution lines – wood poles	41 years
Distribution lines – steel poles	50 years
Distribution underground cables	60 years
Distribution transformers	35 years
Distribution switchgear	35 years
Street lighting	20 years
Distribution meters and services	25 years
Distribution IT	**6 years**
Distribution SCADA and communications	10.16 years
Distribution other, non-network	10.16 years

Table 72 provides details of accelerated depreciation for the distribution assets that are forecast to be decommissioned through the State Underground Power Program.

Table 72: Distribution accelerated depreciation by asset class

($ million real as at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17
Distribution lines – wood poles	2.6	0.3	0.0	0.0	0.0
Distribution lines – steel poles	0.0	0.0	0.0	0.0	0.0
Distribution underground cables	0.0	0.0	0.0	0.0	0.0
Distribution transformers	0.7	0.1	0.0	0.0	0.0
Distribution switchgear	0.2	0.0	0.0	0.0	0.0
Street lighting	0.0	0.0	0.0	0.0	0.0
Distribution meters and services	0.0	0.0	0.0	0.0	0.0
Distribution IT	0.0	0.0	0.0	0.0	0.0
Distribution SCADA and communications	0.0	0.0	0.0	0.0	0.0
Distribution other, non-network	0.0	0.0	0.0	0.0	0.0
Distribution land and easements	0.0	0.0	0.0	0.0	0.0

($ million real as at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17
TOTAL	**3.4**	**0.5**	**0.0**	**0.0**	**0.0**

10.3.4 Asset disposals

Consistent with the approach in AA1 and AA2, we have not forecast any asset disposals over the AA3 period. We will adjust the capital base for actual asset disposals that occur over the AA3 period when setting the capital base for the AA4 period. We will continue to value the asset disposals based on the gross asset sales proceeds.

10.4 Treatment of depreciation in establishing the opening capital base for AA4

We will establish the capital base at the commencement of AA4 using actual depreciation for categories of investment *not* subject to the IAM. *Forecast* depreciation across AA3 will be used for categories of investment that are subject to the IAM.

This is different to the approach used to determine the AA3 opening capital base, where we have used forecast depreciation for the AA2 period across *all categories* in determining the opening capital base for the AA3 period.

We have not used actual depreciation to calculate the AA3 capital base as we did not declare our intention to do this at the beginning of the AA2 period. Using actual depreciation provides the business an incentive to spend capital expenditure efficiently where service is not affected[207], therefore it is important that this incentive is established at the beginning of the period so there is transparency.

Using actual depreciation to establish the AA4 capital base meets the Access Code objective as it promotes economically efficient investment in the network by providing an incentive to reduce capital expenditure. Customers benefit from reductions in capital expenditure over time through lower tariffs than would have otherwise been the case if the incentive did not exist.

Using forecast depreciation results in no revenue gain or loss from differences between forecast and actual depreciation. Therefore it is appropriate to continue using forecast depreciation for capital expenditure that *is* subject to the IAM.

10.5 AAI Guidelines provisions

The requirements regarding the establishment of the opening capital base are detailed in section 4.5 of the AAI Guidelines.

Table 73 details the requirements with a cross reference to the relevant section of this AAI.

Table 73: AAI Guidelines compliance for the opening capital base

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.5.1	*The access arrangement information must set out the proposed capital base for the start of the access arrangement period.*	Section 10.2.3 and 10.2.4

[207] This is consistent with the capital expenditure incentives adopted by the AEMC – p99, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No 18*, Australian Energy Market Commission, 16 November 2006.

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.5.1	*The access arrangement information must … provide evidence that it has been calculated in a manner which is consistent with the objectives of the Access Code.*	Section 10.2.1
4.5.1	*The opening capital base must be calculated separately for covered transmission services and covered distribution services.*	Section 10.2.3 and 10.2.4
4.5.2	*If the capital base is calculated by a roll-forward calculation as described in the note to section 6.48 of the Access Code, the access arrangement information must include an explanation of the calculation method and details of all amounts, values and other parameters used by the service provider in the calculation.*	Section 10.2.1
4.5.2	*Actual expenditure data for the current access arrangement period may not be available at the time an access arrangement proposal is submitted. To the extent that actual expenditure data is available, this should be provided, and supplemented with estimates and up-to-date forecasts.*	Actual expenditure data for 2011/12 is not available at the time the access arrangement proposal was submitted. Section 10.2.3 and 10.2.4 reflect actual data and up-to-date forecasts.
4.5.3	*Evidence must be provided to demonstrate that any capital expenditure added to the capital base relating to a new facilities investment meets the new facilities investment test set out in section 6.51A of the Access Code*	Section 10.2.4

The requirements regarding the forecast capital base over AA3 are detailed in section 4.4.5 of the AAI Guidelines.

Table 74 details the requirements with a cross reference to the relevant section of this AAI.

Table 74: AAI Guidelines compliance for the capital base over AA3

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.4.5	*A proposal for target revenue must set out details of the forecast capital base for each year of the access arrangement, calculated separately for covered transmission services and covered distribution services*	Section 10.3.1 and 10.3.2
4.4.5	*including as a minimum details of:* • *the opening capital base, consistent with the requirements set out in section 4.5 of these guidelines*	Section 10.3.1 and 10.3.2
4.4.5	• *forecast capital expenditure, consistent with the requirements set out in section 4.4.1 of these guidelines*	Section 8, 10.3.1 and 10.3.2
4.4.5	• *forecast depreciation, consistent with the requirements of section 4.4.2 of these guidelines*	Section 10.3.3

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.4.5	• *the return on the capital base, including details of how this has been calculated and evidence supporting the assumptions made*	This information is presented with the total revenue requirement. See section 13.2

The requirements regarding depreciation are detailed in section 4.4.2 of the Authority's *Guidelines for Access Arrangement Information.*

Table 75 details the requirements with a cross reference to the relevant section of this AAI.

Table 75: AAI Guidelines compliance for the depreciation of the capital base

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.4.2	*Statements of depreciation allowances must be accompanied by:* • *details of the calculation method of the allowances for each category of assets and all values of parameters used in the calculation; and*	Section 10.3.3
4.4.2	• *identification of, and reasons for, any accelerated depreciation of an asset.*	Section 10.3.3

11 Return on investment

The rate of return on investment is a critical determinant of Western Power's regulated revenue cap. Under the Access Code, the rate of return is applied to the projected capital base at the beginning of each year for the purpose of determining the return on the projected capital base. The return on investment forms part of the building blocks from which total revenue is calculated.

This chapter details the calculation of Western Power's proposed rate of return on its capital base during the AA3 period. It explains the methods and assumptions we have applied to derive the proposed allowance using the weighted average cost of capital (WACC).

There is a significant degree of imprecision and subjectivity involved in estimating the WACC. There is no single objectively determinable 'correct' estimate of the WACC. It is widely recognised however, that very large costs to consumers and society would arise over the long term if regulators set the WACC at a level that is too low to encourage adequate on-going network investment.

11.1 Key messages

- We have calculated the real pre-tax WACC using a formulation – including the Capital Asset Pricing Model (CAPM) – which is consistent with the approach accepted by the Authority in AA2 and subsequent access arrangement determinations for other businesses.
- In formulating our proposal we have obtained independent expert advice on the WACC and its constituent parameters. We have examined recent regulatory WACC decisions made by the Australian Energy Regulator (AER), as well as the decisions of the Australian Competition Tribunal in recent appeals by regulated companies of aspects of those decisions. We have had regard to recent developments in global capital markets, which continue to exhibit high volatility and uncertainty in the wake of the global financial crisis. We have also examined the impact of specific factors that affect our required returns.
- Section 6.4 of the Access Code requires an access arrangement to have the objective of giving Western Power an opportunity to earn target revenue that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.
- In accordance with the Access Code requirements and having regard to the empirical evidence, we propose a WACC value of 8.82% real pre-tax. This lies towards the lower end of the reasonable range of WACC values (8.49% to 10.25% real pre-tax) we have estimated.
- The adoption of a WACC point estimate of 8.82% real pre-tax minimises the upward pressure on our revenue requirements, while providing a WACC that is sufficient to attract funds in competitive capital markets to ensure efficient ongoing investment in essential electricity network infrastructure, for the long term benefit of Western Australian electricity consumers.

11.2 Regulatory framework

The provisions of the Access Code that apply to our estimation of the WACC are set out in the box below.

Access Code provisions

Section 6.4

The price control in an access arrangement must have the objectives of:

a) *giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:*

   i. *an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved.*

On 22 April 2010 the Authority issued a notice advising that its preferred WACC Methodology published on 25 February 2005, had expired and hence no longer applied to covered electricity networks under the Access Code. The Authority also advised that it had decided not to issue a new determination on the preferred WACC methodology for covered electricity networks.

In the absence of a WACC Methodology, the WACC has been estimated in a manner consistent with **section 6.66** of the Access Code, which requires that a WACC proposal:

a) *must represent an effective means of achieving the Code objective and the objectives in section 6.4; and*

b) *must be based on an accepted financial model such as the Capital Asset Pricing Model.*

11.3 Approach to estimating the WACC

To assist in the estimation of the WACC, we sought expert advice on the WACC and its constituent parameters from two independent sources: Ernst & Young and Strategic Finance Group (SFG). See Appendix X.1: SFG report – An appropriate equity beta estimate for Western Power and Appendix X.2: E&Y report – Advice on aspects of equity beta estimation.

We have had particular regard to recent developments in global capital markets – most notably the ongoing high level of volatility in the wake of the global financial crisis and the ongoing uncertainty surrounding sovereign debt in Europe and the United States.

We also examined recent regulatory WACC decisions made by the AER under the National Electricity Rules, as well as the decisions of the Australian Competition Tribunal in related appeals. Our WACC proposal also reflects our consideration of specific factors that affect our required returns. Specifically, we have considered the additional risk of capital loss that is borne by shareholders because of the Authority's ex-post application of the new facilities investment test to determine the amount of our actual capital expenditure that will be included in the capital base as required under the Access Code.

We have adopted a pre-tax real formulation of the WACC. This approach is identical to the one approved by the Authority for AA2. It is also consistent with the Authority's most recent access arrangement determination (under the National Gas Rules), in which the Authority stated that a real pre-tax WACC formulation was appropriate and also consistent with the Authority's preferences[208]. We consider that this formulation meets the Access Code requirements and remains appropriate for calculating the WACC for AA3.

The pre-tax real WACC formulation is as follows:

$$\mathbf{WACC_{real\ pre\text{-}tax} = [(1 + WACC_{nominal\ pre\text{-}tax}) / (1 + \pi_e)] - 1}$$

where:

$$\mathbf{WACC_{nominal\ pre\text{-}tax} = R_e * E/V * [1 / (1 - T_c (1 - \gamma))] + R_d * D/V}$$

$\mathbf{R_e}$ is the nominal post-tax expected rate of return on equity – the cost of equity

$\mathbf{R_d}$ 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

[208] page 52, *Final decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution Systems*, ERA, 28 February 2011,.

T_c is the corporate tax rate

γ (gamma) is the value of franking credits created, as a proportion of their face value

π_e is expected inflation

Under this approach, the cost of equity, (R_e), is determined using the Capital Asset Pricing Model (CAPM) as follows[209]:

$$R_e = R_f + \beta.MRP$$

where

R_f is the risk free rate

β is a measure of the systematic risk of Western Power, relative to the market and

MRP is the market risk premium

The cost of debt (R_d) is estimated as the risk free rate (R_f) plus a debt risk premium (DRP). The cost of debt also includes an additional allowance for debt issuance costs.

The WACC formulation set out above is comprised of a number of constituent parameters, some of which cannot be measured directly and many of which are subject to estimation error. As already noted, imprecision and subjectivity are involved in estimating the WACC. Ultimately however, a single 'point estimate' of the WACC is required for use in the revenue building blocks formula, to calculate our target revenue.

Given the uncertainty associated with estimating certain WACC parameters, we have sought to identify a reasonable range for those parameters and a corresponding reasonable range for the real pre-tax WACC. Our point estimate of the WACC is drawn from within the reasonable range.

Section 11.4 below explains the basis for the values for each WACC parameter.

Section 11.5 concludes by presenting an overview of the WACC estimation.

11.4 WACC parameters

11.4.1 Averaging period for risk free rate and debt risk premium

We will lodge a separate and confidential request with the Authority to agree, prior to the final decision, the averaging period for the risk free rate and debt risk premium that is to be adopted for the purpose of the Authority's final decision. We request that the agreed averaging period remains confidential until the Authority delivers its final decision.

This approach provides certainty regarding the averaging period to be used, thus enabling a point estimate of the WACC to be calculated without further adjustment, for the purpose of determining our target revenue for the final decision. This approach is consistent with the Authority's most recent final decision (made in February 2011 for WA Gas Networks Pty Ltd).

For the purpose of calculating the WACC for this proposal, we have adopted a 20 business day averaging period for the risk free rate and debt risk premium commencing on 4 May 2011 and ending on 31 May 2011.

11.4.2 Nominal risk free rate

We have adopted the yield on ten-year Commonwealth bonds as a proxy for the nominal risk free rate. This approach was accepted by the Authority for the purpose of estimating our

[209] The CAPM is widely used for this purpose, and its use is contemplated by clause 6.66(b) of the Access Code. The CAPM was applied to determine Western Power's cost of equity for AA2.

WACC for AA2. It was also accepted by the Authority in its Draft Decision (of August 2010) for WA Gas Networks Pty Ltd. However, in its most recent decision (the Draft Decision of March 2011 on the Dampier to Bunbury Natural Gas Pipeline) the Authority adopted a five year term.

The Authority's adoption of a five year term for the risk free rate is based on its view that there are strong grounds for matching the term to maturity of debt with the access arrangement period. However, we note that the maturity of debt issuance is a separate issue to the maturity of the risk free rate used in the CAPM to estimate the cost of equity.

We consider that the term of the risk free rate used in the CAPM should be 10 years in order to achieve:

- consistency with how the MRP has been estimated historically (i.e. relative to the 10 year risk free rate)
- consistency with the objective of limiting volatility in the cost of capital allowance (protecting both customers and businesses from this volatility)
- consistency with the price control objectives set out in section 6.4 of the Access Code, which in effect requires that the cost of equity be not underestimated

We note that our position is consistent with that of the AER, which stated in its most recent decision in June of this year[210]:

> *The AER has accepted the use of the yield on 10 year Commonwealth Government Securities (CGS) as the proxy for the risk free rate. To maintain consistency within the CAPM, the MRP should also be estimated using the yield on 10 year CGS as the proxy for the risk free rate. The Australian Competition Tribunal has also noted the importance of consistency between the term of the risk free rate and the MRP [in Australian Competition Tribunal, Application by GasNet Australia (Operations) Pty Ltd [2003] ACompT 6, p24.].*

The nominal risk free rate is estimated from the annual yield of Commonwealth Government Securities, using the indicative mid rates published by the Reserve Bank of Australia. Currently, there are no Commonwealth Government bonds maturing in exactly ten years. Therefore, the appropriate nominal risk free rate has been estimated by interpolating on a straight line basis between the 15 May 2021 and 15 July 2022 Commonwealth Government bond yields.

Based on this methodology we propose a nominal risk free rate of 5.40%.

11.4.3 Capital structure

Capital structure refers to the mix of debt and equity used to finance an asset or business. The WACC formulation produces an estimate of the cost of capital of an asset that is funded by a mix of equity and debt financing. The contribution made by the respective costs of equity and debt to the WACC must be weighted in proportion to the mix of these two funding sources in the capital structure. Therefore, one of the WACC parameters that must be specified is the capital structure.

In its AA2 determination, the Authority accepted the use of a 60% debt to total assets benchmark capital structure. A capital structure of 60% debt to total assets is adopted almost universally by Australian regulators. It was affirmed as an appropriate benchmark in the AER's 2009 review of WACC parameters[211]. It has also been accepted by the Authority in its

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[210] page 173, *Envestra Ltd Access arrangement proposal for the Qld gas network 1 July 2011 – 30 June 2016*, AER, June 2011,.

[211] page v, AER, *Electricity transmission and distribution network service providers Review of the weighted average cost of capital (WACC) parameters, Final Decision*, 2009.

February 2011 final decision on WA Gas Networks and in its March 2011 draft decision on the Dampier to Bunbury Pipeline.

Accordingly, we propose to adopt a benchmark capital structure of 60% debt to total assets for AA3.

11.4.4 Market risk premium

The market risk premium (MRP) is the expected return over the risk free rate that investors require to invest in a well-diversified portfolio of assets. It represents the risk premium that investors expect to earn for bearing systematic or non-diversifiable risk.

In arriving at our proposed value for the MRP we have considered the analysis and evidence in the AER's 2009 review of the WACC parameters as well as the more recent expert reports[212] provided by Envestra to the AER during Envestra's 2011–2016 access arrangement review.

The AER's 2009 WACC parameter review concluded that the appropriate value for the MRP for electricity transmission and distribution network providers is 6.5%[213]. It is noted that prior to the AER's WACC review, an MRP of 6% was adopted in the AER's decisions. However, at the time of the WACC review the AER acknowledged the uncertainty in the market due to the onset of the global financial crisis (GFC). The AER considered one of two scenarios could have explained market conditions at that time:

- the prevailing medium-term MRP was above the long-term MRP, but would return to the long term MRP over time
- there had been a structural break in the MRP and the forward looking long-term (and consequently also the prevailing) MRP is above the long-term MRP that previously prevailed

Due to the uncertainty about the effects of the GFC on future market conditions the AER's WACC review concluded that it was necessary to depart from the previously adopted forward looking MRP estimate of 6% and to increase it to 6.5%.

However, in June 2011 the AER's most recent decision[214] stated:

> *The significant uncertainty that characterised markets at the time of the WACC review has substantially diminished. The prevailing conditions in the market for funds have eased... The AER's approach of increasing the MRP to 6.5 per cent at the time of the WACC review is no longer appropriate.*

We consider that the heightened volatility of world financial markets in the weeks immediately following the publication of the AER's final decision in June provides clear evidence that there remains significant market uncertainty and a very strong case for adopting an MRP of at least 6.5%. We note that Envestra has appealed the AER's decision on the MRP. We would expect the outcome of that appeal to have a significant bearing on the Authority's consideration of this matter.

There remains considerable uncertainty involved in estimating the forward-looking MRP. It is therefore appropriate to identify a reasonable range of estimates for this parameter.

[212] These reports include: *Comments on Market Risk Premium in Draft Decision by AER for Envestra,* Value Advisor Associates, March 2011; *Issues affecting the estimation of MRP,* SFG, March 2011; *WACC Estimation,* CEG, March 2011; *Estimating the cost of capital under the NGR,* CEG, September 2010.
[213] *Electricity transmission and distribution network service providers Review of the weighted average cost of capital (WACC) parameters, Final Decision, AER, 2009.*
[214] p50 – 51, *Final Decision: Envestra Ltd Access arrangement proposal for the SA gas network 1 July 2011 – 30 June 2016*, AER, June 2011.

Historically, the value for the MRP has extended up to 8%[215], suggesting that the AER's WACC review estimate of 6.5% is at the low end of the reasonable range, notwithstanding the effects of the global financial crisis. The Strategic Finance Group's (SFG) analysis[216] concludes that 6.5% is a reasonable lower bound point estimate of the MRP in the prevailing conditions in capital markets. An estimate of 8% for the upper bound of the MRP range is supported by evidence and analysis provided by CEG[217] for Envestra.

On this basis, we consider that a reasonable estimate of the MRP falls between 6.5% and 8%. This range is consistent with the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved and current capital market conditions.

11.4.5 Effective tax rate

An estimate of the effective tax rate is required to derive the pre-tax WACC. For this purpose, we have applied the statutory corporate tax rate of 30%. This rate was also adopted by Western Power and accepted by the Authority in AA2. More recently, in its latest decision[218], the Authority approved a proposal for the use of the corporate tax rate in a pre-tax WACC calculation, noting that in previous WACC determinations the Authority has assumed the effective tax rate of the utility businesses to be equal to the statutory rate of corporate income tax.

11.4.6 Value of imputation credits (gamma)

The value of gamma is the value of franking credits distributed to shareholders. Gamma is the product of two components, the distribution ratio (F) and utilisation rate or 'theta' (θ). The distribution ratio represents the proportion of franking credits that are distributed to shareholders by attaching them to dividends and theta is the value of each franking credit.

This is represented by the following formula:

$$\gamma = F \times \theta$$

The AER's 2009 WACC review increased gamma from 0.5 (the value which had previously been adopted by Australian regulators) to 0.65[219]. However, in October 2010 the Australian Competition Tribunal (the Tribunal) found there was substantial evidence to suggest that the AER had made a material error of fact and exercised its discretion incorrectly in the calculation of both the distribution ratio and utilisation rate[220].

Subsequently, both of the components of gamma were reviewed by experts, the AER and the Tribunal. These findings have resulted in revisions to the calculation of the distribution ratio and utilisation rate, which now provide for a gamma of 0.25.[221]

In arriving at its decision on the distribution ratio the Tribunal considered a submission filed by the AER. The Tribunal found that there is no empirical data capable of supporting a

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[215] p166, Principles of Corporate Finance 1st Australian edition, Brealey R, Myers S, Partington G, Robinson D, 2000.
[216] *Issues affecting the estimation of MRP, SFG, March 2011.*
[217] *WACC Estimation, CEG,* March 2011 and *Estimating the cost of capital under the NGR, CEG,* September 2010.
[218] p172, *Draft Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, ERA, March 2011.
[219] page v, *Electricity transmission and distribution network service providers Review of the weighted average cost of capital (WACC) parameters, Final Decision*, AER, 2009.
[220] Application by Energex Limited (Gamma) (no 2) [2010] ACompT 7, 13 October 2010.
[221] *Application by Energex Limited (Gamma) (no 5) [2011] ACompT 9*, 12 May 2011.

distribution ratio higher than 70%[222] and concluded that the appropriate estimate for the distribution ratio is 70%. Consistent with the Tribunal's decision[223], we propose that the distribution ratio is 70%.

In its decision on the utilisation rate[224], the Tribunal considered evidence from a range of submissions including a 'state of the art' dividend drop-off study[225]. The Tribunal concluded that the dividend drop-off methodology is

> *…the best dividend drop-off study currently available for the purpose of estimating gamma…*[226]

and therefore, the dividend drop-off estimate of 35% for the utilisation should be accepted as the best estimate available. In its decision the Tribunal also noted that it was unable to reach any conclusion on the use of tax statistics for the estimation of an upper limit of the utilisation rate.[227] In accordance with the Tribunal's reasoning and conclusions[228], we propose a value for the utilisation rate of 35%.

Following the Tribunal's decision on gamma, the AER delivered its June 2011 Final Decision for Envestra and APT Allgas, in which it stated:

> *There is no new evidence currently before the AER that would cause it to depart from the findings of the Tribunal in respect of gamma.*[229]

Western Power therefore proposes a value for gamma of 0.25 (being the product of the distribution ratio of 70% and the utilisation rate of 35%).

11.4.7 Debt margin

The debt margin is composed of two elements:

- the debt risk premium (which is the additional return required by investors above the risk free rate for providing debt finance to a firm with a particular credit rating)
- the cost of issuing debt

The total allowance for the cost of debt (R_d) is calculated by adding the debt margin to the risk free rate.

Explanations of the basis of our assumed benchmark credit rating, the debt risk premium range and the allowance for the cost of issuing debt are set out below.

11.4.7.1 Benchmark credit rating

The debt risk premium for a particular business will reflect its credit rating. We support the adoption of a BBB+ credit rating assumption for a benchmark efficient firm. This is consistent with the approaches adopted by the Authority[230] and the AER[231].

[222] *Application by Energex Limited (Gamma) (no 3) [2010] ACompT 9*, 24 December 2010.
[223] *Application by Energex Limited (Gamma) (no 5) [2011] ACompT 9*, 12 May 2011.
[224] *Application by Energex Limited (Gamma) (no 5) [2011] ACompT 9*, 12 May 2011.
[225] *Dividend drop-off estimate of theta*, SFG Consulting, 21 March 2011.
[226] *Application by Energex Limited (Gamma) (no 5) [2011] ACompT 9*, 12 May 2011.
[227] *Application by Energex Limited (Gamma) (no 5) [2011] ACompT 9*, 12 May 2011.
[228] *Application by Energex Limited (Gamma) (no 5) [2011] ACompT 9*, 12 May 2011.
[229] p57, *Final Decision Envestra, Access arrangement proposals*, AER, June 2011.
[230] p68, *Final decision on WA Gas Networks Pty Ltd proposed revised access arrangement for the Mid-West and South-West Gas Distribution Systems*, ERA, 2011.
[231] pV, *Electricity transmission and distribution network service providers review of the weighted average cost of capital (WACC) parameters, Final Decision*, AER, 2009.

11.4.7.2 Debt risk premium

As demonstrated in our submission of 7 January 2011 to the Authority's Discussion Paper titled *Estimating the Debt Risk Premium,* the best available estimate of the benchmark cost of debt for a BBB+ credit rating is provided by Bloomberg BBB fair value curves.

Our approach to estimating the debt risk premium is consistent with our January 2011 submission to the Authority, in which it was demonstrated that there is insufficient evidence to exclude the Bloomberg yield curves from the calculation of the debt risk premium for the following reasons:

- the analysis contained in the Authority's Discussion Paper comparing the Bloomberg seven-year fair yield curve with observed yields does not include all of the bonds that match the Authority's search criteria. Inclusion of these bonds results in the Bloomberg seven-year fair yield curve being a better match to the observed bond yields in the Australian bond market
- the term to maturity assumption in the Bloomberg fair yield curves better aligns with the ten-year term that currently underpins other elements of the WACC, such as the risk free rate
- other Australian regulators continue to include the Bloomberg yield curves in the calculation of the debt risk premium
- KPMG has found that extrapolating the Bloomberg BBB seven-year fair yield curve using the spread between seven and ten-year Commonwealth Government Securities yields represents a close proxy to the Bloomberg BBB ten-year fair yield curve

We also presented evidence that adopting an assumption of a borrowing term less than ten years will understate the debt risk premium applicable to an infrastructure business, for the following reasons:

- infrastructure businesses adopt long term financing practices which are consistent with the life of the assets that underpin their business. There is evidence to support the practice of long term financing through Australian businesses' recent debt raisings in Australia and offshore[232]
- the AER's recent review of the WACC parameters for electricity transmission and distribution network businesses (completed in May 2009) considered moving to a five-year debt financing assumption and found that such a maturity assumption would not be consistent with the actual debt financing practices of regulated electricity businesses. The AER concluded that adopting a five year term would be expected to under-compensate the benchmark business

We stands by our submission of 7 January 2011 to the Authority, notwithstanding the Authority's latest decision[233], in which it applied the approach foreshadowed in its December 2010 Discussion Paper.

Importantly, on 9 June 2011, the Australian Competition Tribunal delivered a decision in an appeal brought by Jemena Gas Networks on how to apply Bloomberg and CBASpectrum data sources to derive the debt risk premium. It is recognised that the Tribunal's decision applies to the facts in that case; in particular, the CBASpectrum data is no longer published,

[232] *Submission to the ERA Discussion Paper – Estimating the Debt Risk Premium*, Western Power, January 2011.
[233] ERA, *Draft Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, March 2011.

so use of that data is not an issue for the Authority's consideration of Western Power's AA3 proposal. Nonetheless, the Tribunal's decision[234] is pertinent in that:

- it finds that the Bloomberg fair yield curve is widely used and market respected
- the appropriate curve from which the debt risk premium for Jemena Gas Networks should be calculated is the Bloomberg fair value curve

To estimate the debt risk premium over a ten-year period it is necessary to extrapolate the Bloomberg BBB seven-year curve out to ten years. A universally accepted extrapolation method does not exist. In recent regulatory decisions the AER has adopted the method of adding the spread of Bloomberg's AAA rated estimates from seven to ten years, as averaged over the last 20 trading days to 22 June 2010, when these estimates were last available[235].

In the past the AER has also supported the use of Bloomberg's Commonwealth Government Securities as a proxy for Bloomberg AAA rated bonds[236]. Extrapolating the Bloomberg seven-year BBB fair yield curve using the spread between seven and ten-year Commonwealth Government Securities yields provides a reasonable method for extrapolating the Bloomberg BBB fair yield curve to ten years[237].

Based on the Bloomberg BBB seven-year fair yield curve extrapolated to ten years, we propose the value for the debt risk premium (over the averaging period commencing on 4 May 2011 and ending on 31 May 2011) lies between 3.83% to 4.30%. This range reflects the estimates obtained using the two alternative extrapolation methods discussed above.

11.4.7.3 Debt issuance costs

Debt issuance or establishment costs represent the transaction costs associated with raising debt capital. In accordance with the methodology established by the Allen Consulting Group[238], the debt margin includes an allowance of 12.5 basis points per year for debt establishment costs. This is consistent with the Authority's approach in AA2 and in its other recent decisions for WA Gas Networks and the Dampier to Bunbury Pipeline.

11.4.7.4 Debt margin

Based on the debt risk premium and debt issuance cost estimates set out above, we propose the reasonable range for the debt margin sampled over the 20 business days to 31 May 2011 is between 3.96% and 4.43%. This allowance will be updated prior to the Authority's final decision, in accordance with the arrangements outlined in section 11.4.1 of this document.

11.4.8 Expected inflation

We have estimated the annual rate of inflation based on the geometric mean over a ten-year period of:

- the CPI forecasts from the most recent Reserve Bank of Australia Statement on Monetary Policy[239]

[234] Application by Jemena Gas Networks (NSW) Ltd (no 5) [2011] ACompT 10 (9 June 2011), paragraphs 62, 64 and 86.
[235] AER 2011, *Envestra Access arrangement proposal for the Qld gas network*, Final Decision.
[236] AER 2010, *AER draft approach for measuring the debt risk premium for the Victorian Electricity Distribution Determinations*, 27 September 2010.
[237] Western Power, *Submission to the ERA Discussion Paper – Estimating the Debt Risk Premium*, January 2011.
[238] ACG, *Debt and equity raising transaction costs*, December 2004, pp. 27-53.
[239] p63, *Statement on Monetary Policy,* Reserve Bank of Australia, May 2011.

- for the remaining years of the 10 year period for which explicit forecasts are not provided, the midpoint (being 2.5%) of the RBA's inflation target of 2% to 3%

This methodology is consistent with the approach accepted by the Authority in AA2 and in its most recent decisions (namely, the WA Gas Networks Final Decision of February 2011 and the Dampier to Bunbury Pipeline Draft Decision of March 2011).

The forecast annual changes in the CPI are:

- 3.25% for the 2011 calendar year
- 3.00% for 2012
- 3.25% for 2013
- 2.5% for the remaining years to December 2020

The geometric average of these forecasts is 2.70%.

11.4.9 Equity beta

The equity beta represents the degree of systematic risk to which the shareholders (owners) of a business are exposed. Systematic or non-diversifiable risk is the risk associated with aggregate market returns. Under the theoretical framework of the CAPM, investors are compensated for bearing systematic risk only. This is because the CAPM assumes that investors can eliminate all other risk by holding a diversified portfolio of assets.

There is considerable uncertainty and imprecision involved in estimating the equity beta. It is therefore appropriate to identify a reasonable range of estimates for this parameter.

To provide an independent expert opinion on this parameter, we engaged Professor Stephen Gray from the Strategic Finance Group (SFG) to undertake analysis and provide advice on an appropriate range for the equity beta, having regard to the requirements of the Access Code. Professor Gray's analysis and evidence is provided in SFG's report *An appropriate equity beta estimate for Western Power*, attached at Appendix X.1: SFG report – An appropriate equity beta estimate for Western Power. The key findings and recommendations from Professor Gray's report are summarised below.

11.4.9.1 Strategic Finance Group analysis and conclusions on equity beta

SFG's report observes that there are two things that determine the relative systematic risk, or equity beta, of a particular firm:

- the type of business that the firm operates
- the amount of financial leverage (gearing) employed by the firm

It is generally accepted that the activities of regulated transmission and distribution network businesses have lower than average systematic risk. It is also clear, however, that such businesses have much higher financial leverage than the average firm. Specifically, the benchmark level of gearing typically assumed for regulated networks is 60% debt to total assets, while the average listed firm has a gearing level of 30% debt to total assets[240].

Since transmission and distribution companies have business activities that are below average risk, but financial leverage that is much higher than average, the two components of equity beta operate in different directions and will tend to offset one another. Consequently, the appropriate a priori expectation is that the equity beta for these businesses is no different from that of the average firm, which is 1.0.[241]

[240] p11, *An appropriate equity beta estimate for Western Power*, SFG, 13 July 2011.
[241] p3, *An appropriate equity beta estimate for Western Power*, SFG, 13 July 2011.

SFG states that one would only move from this default position to the extent that:

- appropriate analysis of the available data suggested that a move away from the default of 1.0 was warranted
- the resulting equity beta value resulted in an estimate of the required return on equity that is economically reasonable and commercially plausible in the circumstances

SFG notes that the current regulatory estimate of equity beta adopted by the AER is 0.8, however that estimate:

- is statistically unreliable and proper analysis of the available data does not warrant a move away from the default value of 1.0
- produces an estimate of the required return on equity that is economically unreasonable and commercially implausible in the circumstances

Consequently SFG considers the regulatory estimate of 0.8 does not produce a regulatory return that is commensurate with the commercial risks involved or sufficient to attract the required amount of capital, given the prevailing conditions in the market.

By contrast, the default estimate of 1.0 (which was applied by the AER prior to the 2009 WACC review) produces an estimate of the required return on equity that is economically reasonable and commercially plausible.

SFG concludes by stating:[242]

> *In our view, 1.0 remains an appropriate point estimate for the equity beta of an electricity transmission and distribution businesses with 60% gearing. Estimates of 0.8 and below fail the tests of reasonableness and plausibility. Symmetrically, estimates well above 1.0 imply implausibly high returns on equity. Consequently, our view is that 0.9 to 1.1 provides a reasonable range for the equity beta of an electricity transmission and distribution businesses [sic] with 60% gearing and meets the requirements of the Code.*

11.4.9.2 Western Australian specific issues

We asked SFG and Ernst & Young to investigate whether there are aspects of the regulatory regime under the Access Code that would support a departure from the 0.8 for the equity beta, which has been adopted by the AER. SFG's report explains that:

- in most respects, Western Power's transmission and distribution network businesses are comparable to the benchmark efficient business that underlies the AER's estimates. One key point of difference is that the Access Code contains a New Facilities Investment Test that must be satisfied before new investment can be included in the capital base. In effect, the regulator must perform an ex-post assessment of the efficiency of capital expenditure
- consequently, there is a risk to investors that some capital expenditure will be disallowed and no return will be generated from it. The Authority has previously acted to reduce the proposed opening capital base for the SWIN under this provision. Comparable entities regulated under the National Electricity Rules face no such risk
- the AER is of the view that risks related to an ex-post review of the efficiency of capital expenditure are systematic in nature and affect the estimate of equity beta[243]

[242] p2-7, *An appropriate equity beta estimate for Western Power*, SFG, 13 July 2011.
[243] page 248-249, *Final Decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, AER, May 2009,.

SFG concludes by reiterating its view that 0.9 to 1.1 provides a reasonable range for the equity beta of a benchmark electricity transmission and distribution business with 60% gearing. SFG notes that the Authority's interpretation of the NFIT suggests that the equity beta estimate for Western Power should be higher than that of the benchmark firm regulated under the National Electricity Rules (0.8) and this would be a relevant consideration when selecting an appropriate point estimate from within the reasonable range.

Ernst & Young's report examined this matter in considerable detail and concluded as follows:

- the evidence presented suggests that an appropriate value for the equity beta of Western Power would lie above the value of 0.8 which has been adopted by the AER for electricity transmission and distribution network businesses
- the requirement to undertake an ex-post assessment of capital expenditure and the fact that the Authority has previously exercised this provision in the way that it has means that investors are exposed to a significant risk that invested capital may not be recovered. The Authority acknowledges that the risk is material. There is evidence to suggest that it is systematic
- under such circumstances, investors in Western Power are likely to require a higher rate of return to compensate for this additional risk exposure
- given that the AER has allowed an equity beta of 0.8 for electricity transmission and distribution network businesses which do not face ex-post capital expenditure disallowance, the appropriate equity beta for Western Power should be above 0.8
- a reasonable upper bound value for the equity beta may, in the context of the views of the AER, be 1.0, on the basis that the systematic risk of Western Power is unlikely to exceed that of the market portfolio due to the nature of demand for electricity

In summary, both SFG and Ernst & Young found that the NFIT arrangements under the Access Code increase the systematic risk to which Wester Power is exposed and this should be reflected in an increased regulatory estimate of equity beta[244].

11.4.9.3 Equity beta for AA3

Based on the evidence summarised above and set out in the accompanying expert reports prepared by SFG and Ernst & Young, we propose that the appropriate range for the value of equity beta is between 0.9 and 1.1.

[244] page 38, *An appropriate equity beta estimate for Western Power*, SFG, June 2011.

11.5 Rate of return

The point estimate for the WACC should be determined using the input parameters from the ranges set out in Table 76.

Table 76: Pre-tax real WACC parameter estimates

Parameter	Basis of estimate	Reasonable range	
Nominal risk free rate*	This is the effective annual nominal yield on 10 year Government bonds interpolated from yields on bonds maturing in May 2021 and July 2022, averaged over a 20 trading day period to 31 May 2011.	5.40%	
Inflation forecast*	This is a 10 year forecast estimated from the inflation forecasts published by the Reserve Bank of Australia (RBA) and the long term inflation target of the RBA. The approach is consistent with that applied recently by other Australian regulators.	2.70%	
Real risk free rate	This value has been calculated from the nominal risk free rate and inflation forecasts set out above.	2.63%	
Equity beta	This range is based on analysis contained in Appendix X.1 (SFG report) and Appendix X.2 (Ernst & Young report).	0.9	1.1
Market risk premium (MRP)	The range is based on the analysis and evidence presented in the AER's 2009 review of the WACC parameters, as well as the more recent expert reports provided by Envestra to the AER during Envestra's 2011–2016 access arrangement approval process. It takes into account the significant market volatility and uncertainty that continues to prevail in the wake of the global financial crisis and on-going concerns regarding sovereign debt in Europe and the United States.	6.5%	8.0%
Capital structure (debt to total value)	This value is consistent with regulatory decisions around Australia. Prevailing market evidence does not provide a compelling case to justify a departure from this benchmark.	60%	
Debt margin*	The range of values reflects the yields on the 7 year BBB Bloomberg fair value yield curve, extrapolated to 10 years using two alternative extrapolation methods. The estimate reflects average yields over a 20 trading day period to 31 May 2011. The estimate also includes an allowance of 12.5 basis points per year for debt establishment costs.	3.96%	4.43%
Effective tax rate	The proposed value is consistent with the Authority's assumption in previous decisions for Western Power and other regulated businesses, that the effective tax rate of the utility businesses is equal to the statutory rate of corporate income tax.	30%	
Value of imputation credits (gamma)	This value is consistent with the decision of the Australian Competition Tribunal made in May 2011 and the subsequent decisions of the AER.	0.25	
Real pre-tax WACC	Plausible combinations of upper and lower bound estimates of the WACC parameters.	8.49%	10.25%

** NOTE: Estimates of the nominal risk free rate, expected inflation and the debt margin will be subject to change to reflect prevailing interest rates and the corresponding 10-year inflation outlook over a sampling period to be agreed (on a confidential basis) between the Authority and Western Power prior to the final decision.*

We propose a WACC value of 8.82% real pre tax. This point estimate lies towards the lower end of the reasonable range of WACC values. It reflects the adoption of the mid-point equity beta estimate (1.0) and lower bound values for the market risk premium (6.5%) and debt risk premium (3.96%).

Our proposal is based on a thorough and robust analysis of the individual parameter values that must be combined to form a reasonable estimate of the WACC. Our proposal satisfies the requirements of the Access Code, including the Access Code objective set out in section 2.1 and the price control objective in section 6.4. As discussed in section 1.2.2 of this document. Our proposed revisions are submitted in the context of section 4.28 of the Access Code. Section 4.28 is, however, particularly relevant given the imprecision and subjectivity involved in estimating the WACC.

12 Other building blocks

This chapter discusses additional components included in the building blocks methodology for calculating target revenue. These are the blue boxes in Figure 97.

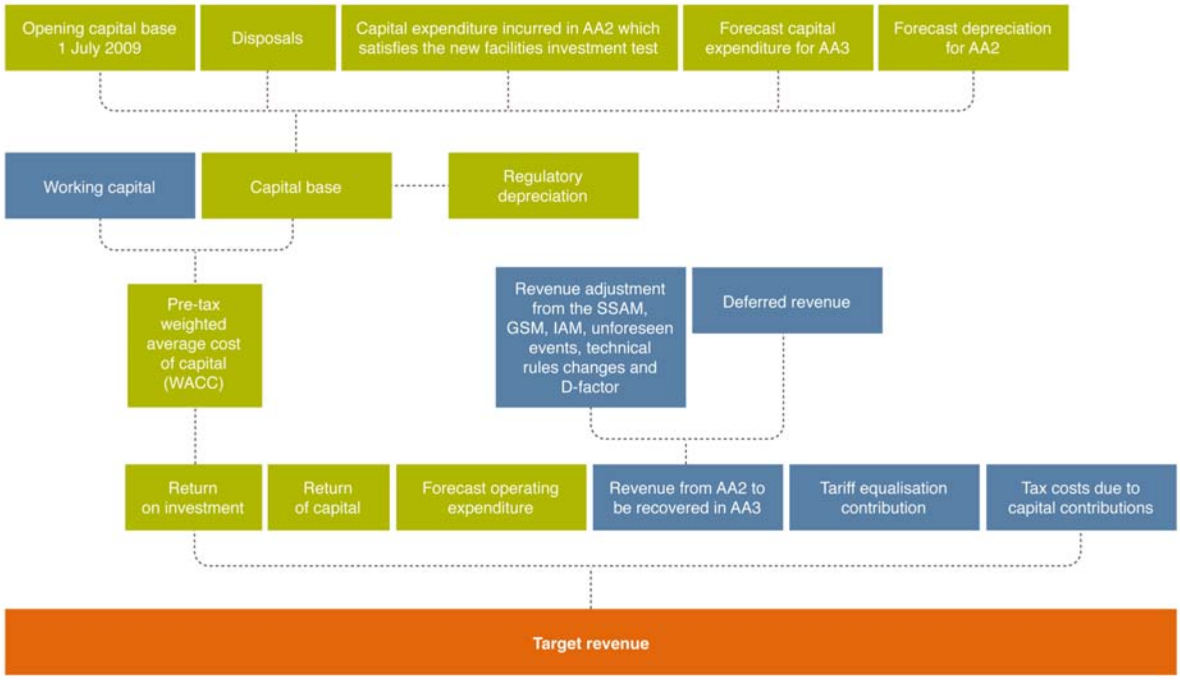

Figure 97: Revenue building blocks

12.1 Key messages

- Our target revenue includes components to cover the following:
  - no adjustment as a result of the gain sharing mechanism, despite achieving strong efficiency gains
  - an adjustment as a result of the service standards adjustment mechanism[245]
  - an adjustment as a result of the investment adjustment mechanism[246]
  - the costs of one unforeseen event – March 2010 storm[247]
  - no adjustment for the costs of changes to the Technical Rules
  - a return on our working capital
  - tariff equalisation contribution (TEC)
  - the full amount of deferred revenue (transmission and distribution) from AA2
  - the tax costs associated with the forecast capital contributions and gifted assets provided by customers

[245] Present value at 30 June 2012.
[246] Present value at 30 June 2012.
[247] Present value at 30 June 2012.

12.2 Performance under adjustment mechanisms

We will return -$32.7 million[248] in revenue in AA3. The adjustments reflect the amounts calculated under various adjustment mechanisms in place during AA2.

The adjustment mechanisms provide performance and cost efficiency incentives and minimise windfall gains and losses including variations from growth forecasts. This section details the amounts, values and other parameters required to calculate the adjustment mechanisms.

Table 77 summarises the financial implications of the adjustment mechanisms on the AA3 target revenue.

Table 77: Performance under adjustment mechanisms during AA2

Adjustment mechanism ($ million real at 30 June 2012)	Present value adjustment to AA3 transmission revenue	Present value adjustment to AA3 distribution revenue
Gain sharing mechanism	0.0	0.0
Service standards adjustment mechanism	-0.7	2.8
Investment adjustment mechanism	-43.6	1.8
Unforeseen events	0.0	6.9
Technical Rules changes	0.0	0.0
D-factor	0.0	0.0
TOTAL	**-44.3**	**11.6**

The value of the adjustment mechanisms reflects *estimated* capital expenditure, operating expenditure, service standard performance and inflation for the year ending 30 June 2012.

We propose that at the commencement of AA4 (1 July 2017) an adjustment to the target revenue for the AA4 period will be made to compensate Western Power (or users) for the revenue foregone (or additional revenue recovered) over AA3 in respect to differences between the actual and forecast for the 2011/12 financial year.

12.2.1 Gain sharing mechanism

There is no adjustment to our target revenue in AA3 as a result of the gain sharing mechanism, despite achieving strong efficiency gains. This is because benefits under the mechanism are dependent on achieving *all* of the 19 service standard benchmarks that were in place during the AA2 period.[249] We were not able to do this in any year of the AA2 period.

The gain sharing mechanism provides an incentive to achieve operating cost efficiencies over AA2. We have applied the gain sharing mechanism in accordance with sections 5.13 – 5.14G of the current access arrangement.

[248] Present value at 30 June 2012.
[249] Under section 5.15C of the current access arrangement, Western Power must meet all 19 service standard benchmarks detailed in sections 3.15 – 3.23 of the current access arrangement in order to receive any benefit under the gain sharing mechanism.

12.2.2 Service standards adjustment mechanism

We have included $2.2 million[250] in the AA3 target revenue in line with the requirements of the SSAM. This amount has been calculated in accordance with sections 5.15 – 5.24B of the current access arrangement.

The SSAM provides an incentive to maintain and improve service above the service standard benchmarks for AA2 by providing financial rewards for performance improvements.

In accordance with the access arrangement provisions, the present value of the adjustment under the SSAM is calculated as if the rewards or penalties in each year immediately follow the relevant performance year.

Our service performance over AA2 is detailed in section 3.8.1 of this document.

12.2.2.1 Adjustment against transmission service standard benchmarks

We have incurred a $0.7 million[251] penalty under the SSAM for performance against the transmission service standard benchmarks in AA2. We have calculated the transmission SSAM in accordance with section 5.24A of the current access arrangement.

Table 78 provides our performance compared with the service standard benchmark and the associated financial penalty or reward for each measure.

Note that the circuit availability benchmark is met when the actual performance is greater than the target. The system minutes benchmarks are met when the actual performance is lower than the target.

Table 78: Transmission service standards adjustment mechanism parameters

	2009/10	2010/11	2011/12 (Forecast)	Present value of incentive
Service standard benchmarks				
Circuit availability (% of total time)	98.0	98.0	98.0	
System minutes interrupted - meshed (minutes)	9.3	9.3	9.3	
System minutes interrupted - radial (minutes)	1.4	1.4	1.4	
Actual service performance				
Circuit availability (% of total time)	98.4	97.9	97.7	
System minutes interrupted - meshed (minutes)	8.9	6.7	9.0	
System minutes interrupted - radial (minutes)	0.8	4.8	1.5	
Service standards adjustment mechanism Adjustment ($ million real at 30 June 2012)				
Circuit availability	1.8	-2.2	-0.8	-1.0
System minutes interrupted - meshed	0.3	1.9	-1.9	0.4
System minutes interrupted - radial	0.2	-1.1	0.9	-0.1
TOTAL	**2.2**	**-1.4**	**-1.8**	**-0.7**

[250] Present value at 30 June 2012.
[251] Present value at 30 June 2012.

12.2.2.2 Adjustment against distribution service standard benchmarks

We have achieved a $2.8 million[252] reward under the SSAM for performance against the distribution service standard benchmarks in AA2. We have calculated the distribution service standards adjustment mechanism in accordance with section 5.24B of the current access arrangement.

Table 79 provides our performance compared with the service standard benchmark and the associated financial penalty or reward for each measure. The service standard benchmarks are met when the actual performance is lower than the target.

Table 79: Distribution service standards adjustment mechanism parameters

	2009/10	2010/11	2011/12 (Forecast)	Present value of incentive
Service standard benchmarks				
SAIDI – CBD	38	38	38	
SAIDI – Urban	165	162	153	
SAIDI – Rural short	259	253	244	
SAIDI – Rural long	612	588	556	
SAIFI – CBD	0.24	0.24	0.24	
SAIFI – Urban	1.92	1.89	1.83	
SAIFI – Rural short	3.12	3.06	2.98	
SAIFI – Rural long	5.00	4.85	4.80	
Actual service performance				
SAIDI – CBD	1	30	22	
SAIDI – Urban	156	120	166	
SAIDI – Rural short	212	192	263	
SAIDI – Rural long	661	529	604	
SAIFI – CBD	0.02	0.23	0.18	
SAIFI – Urban	1.55	1.31	1.94	
SAIFI – Rural short	2.33	2.11	3.00	
SAIFI – Rural long	4.17	3.86	4.58	
Service standards adjustment mechanism Adjustment ($ million real at 30 June 2012)				
SAIDI – CBD	8.9	-7.0	1.9	4.4
SAIDI – Urban	2.2	7.9	-13.2	-1.9
SAIDI – Rural short	0.4	0.1	-0.7	-0.1
SAIDI – Rural long	-0.4	1.0	-1.0	-0.4
SAIFI – CBD	2.5	-2.4	0.6	0.8
SAIFI – Urban	4.2	2.4	-7.8	-0.3
SAIFI – Rural short	0.4	0.1	-0.5	0.1

[252] Present value at 30 June 2012.

	2009/10	2010/11	2011/12 (Forecast)	Present value of incentive
SAIFI – Rural long	0.4	0.1	-0.4	0.2
TOTAL	**18.5**	**2.2**	**-21.1**	**2.8**

12.2.3 Investment adjustment mechanism

We have subtracted $41.7 million[253] from the AA3 target revenue in line with the requirements of the investment adjustment mechanism. This amount has been calculated in accordance with sections 5.49 – 5.53 of the current access arrangement.

The investment adjustment mechanism provides for an adjustment to target revenue that ensures Western Power and its customers are financially neutral as a result of differences between actual and forecast capital expenditure in certain expenditure categories. These categories are growth-related capital, the State Underground Power Program and Rural Power Improvement Program.

The investment adjustment mechanism is calculated by comparing the forecast capital expenditure with the actual incurred capital expenditure that meets the requirements of section 6.51A of the Access Code. The adjustment amount is calculated using the revenue building blocks methodology to calculate the return on and return of due to the capital expenditure. The amount of the investment adjustment mechanism is the difference between the building blocks adjusted for the time value of money and inflation. The detailed calculations are set out in the revenue model in Appendix F: Revenue model summary.

12.2.3.1 Adjustment against transmission growth capital expenditure

We will return $43.6 million[254] to customers via the AA3 transmission target revenue due to differences between AA2 actual and forecast transmission growth capital expenditure.

The following table provides the parameters required to calculate the transmission investment adjustment mechanism in accordance with the current access arrangement. Details of our forecast and actual capital expenditure during AA2 are available in section 3.7 of this document.

[253] Present value at 30 June 2012.
[254] Present value at 30 June 2012.

Table 80: Transmission capital expenditure[255] subject to the IAM

($ million real at 30 June 2012)	2009/10	2010/11	2011/12 (Forecast)	Present value
Forecast capital expenditure (net)				
Capacity expansion	149.4	174.3	183.1	
Customer-driven	67.2	142.9	252.5	
Generation driven	28.8	147.6	97.6	
TOTAL	**245.4**	**464.8**	**533.2**	
Revenue – return on and return of	0.0	23.6	68.3	
Actual capital expenditure (net)				
Capacity expansion	115.0	52.0	64.1	
Customer-driven	23.4	24.6	33.2	
Generation driven	28.6	5.0	0.0	
TOTAL	**167.0**	**81.6**	**97.3**	
Revenue – return on and return of	0.0	17.3	31.5	
Investment adjustment mechanism	**0.0**	**-6.3**	**-36.8**	**-43.6**

12.2.3.2 Adjustment against distribution capital expenditure

We will add $1.8 million[256] to the AA3 distribution target revenue due to differences between AA2 actual and forecast distribution growth and State Underground Power Program capital expenditure.

The following table provides the parameters used to calculate the distribution investment adjustment in accordance with the current access arrangement. Details of our forecast and actual capital expenditure during AA2 are available in section 3.7 of this document.

Table 81: Distribution capital expenditure[257] subject to the IAM

($ million real at 30 June 2012)	2009/10	2010/11	2011/12 (forecast)	Present value
Forecast capital expenditure (net)				
Capacity expansion	89.2	113.8	107.6	
Customer-driven	106.3	106.5	106.3	
State Undergrounding Power Program (SUPP)	6.0	5.8	5.7	
Rural Power Improvement Program (RPIP)	8.7	0.0	0.0	
TOTAL	**210.2**	**226.2**	**219.6**	
Revenue – return on and return of	0.0	21.5	44.1	

[255] Capital expenditure net of capital contributions.
[256] Present value at 30 June 2012.
[257] Capital expenditure net of capital contributions.

($ million real at 30 June 2012)	2009/10	2010/11	2011/12 (forecast)	Present value
Actual capital expenditure (net)				
Capacity expansion	66.5	35.4	54.4	
Customer-driven	140.8	156.0	128.8	
State Undergrounding Power Program (SUPP)	16.4	12.0	19.6	
Rural Power Improvement Program (RPIP)	8.7	-0.2	0.0	
TOTAL	**232.3**	**203.3**	**202.8**	
Revenue - return on and return of	0.0	23.2	44.1	
Investment adjustment mechanism	**0.0**	**1.8**	**-0.1**	**1.8**

12.2.4 Cost recovery for unforeseen events

We are seeking an adjustment to target revenue for AA3 of $6.9 million[258] to recover the efficient and unrecovered distribution related costs for the March 2010 storm. Sections 5.4 to 5.6 of the current access arrangement permits Western Power, in certain circumstances, to include unforeseen costs resulting from a force majeure event in its target revenue for the next access arrangement period:

Section 5.4

> *If a force majeure event occurs which results in Western Power incurring unrecovered costs during the access arrangement period then Western Power will, as part of its proposed access arrangement for the next access arrangement period, provide a report to the Authority setting out:*
>
> *a) a description of the nature of the force majeure event;*
>
> *b) a description of the insurance cover that Western Power had in place at the time of the force majeure event; and*
>
> *c) a fair and reasonable estimate of the unrecovered costs borne by Western Power during the access arrangement period as a result of the occurrence of the force majeure event*

Section 5.5

> *Pursuant to sections 6.6 to 6.8 of the Code, an amount will be added to the target revenue for the covered network for the next access arrangement period in respect of the unrecovered costs relating to a force majeure event which occurred in the access arrangement period, calculated in accordance with the methodology described in section 4 of Appendix 8 of this Access Arrangement.*

Section 5.6

> *For the avoidance of doubt, a force majeure event includes but is not limited to any costs arising from the introduction of an emissions trading scheme; full retail contestability; and the roll-out of Advanced Interval Meters to the extent that such costs were not included in the calculation of target revenue for the access arrangement period or otherwise addressed through the Trigger Event provisions in section 8 of this Access Arrangement.*

[258] Present value at 30 June 2012.

We submit that the 22 March 2010 storm, which caused significant damage to the Western Power Network, was a force majeure event which resulted in costs that were unable to be recovered through our insurance policies. These costs are eligible for recovery in AA3 under the terms of our access arrangement.

In accordance with the requirements of the AAI Guidelines, the following section provides:

- a description of the relevant force majeure event
- a description and justification that we held relevant insurance to the standard of a reasonable and prudent person
- the amount, or forecast amount, of unrecovered costs sought to be recovered through an adjustment to target revenue
- evidence that the amount to be recovered through an adjustment to target revenue is an amount that does not exceed the costs which would have been incurred by a service provider efficiently minimising costs
- evidence that the amount to be recovered through an adjustment to target revenue is an amount in addition to any amount that is recoverable through a claim on an insurance policy

Description of the March 2010 Storm

On Monday 22 March 2010, a severe storm front passed over Perth bringing heavy rainfall, hail and strong winds up to 120 kilometres per hour. The Bureau of Meteorology reported rainfall up to 45 millimetres in some areas, significant lightning activity and the largest hail known to have occurred in Perth, all of which caused significant damage[259].

The storm caused severe disruptions to the network. In total, power supplies for approximately 250,000 customers were affected and around 8000 MWh of load was unavailable for 31 hours.

Figure 98 demonstrates the severity of the storm which affected six substations, contributing to the peak of 167,777 customers with interrupted supply.

[259] *Severe Thunderstorms in Perth and Southwest Western Australia, 22 March 2010*, Bureau of Meterology, 26 March 2010

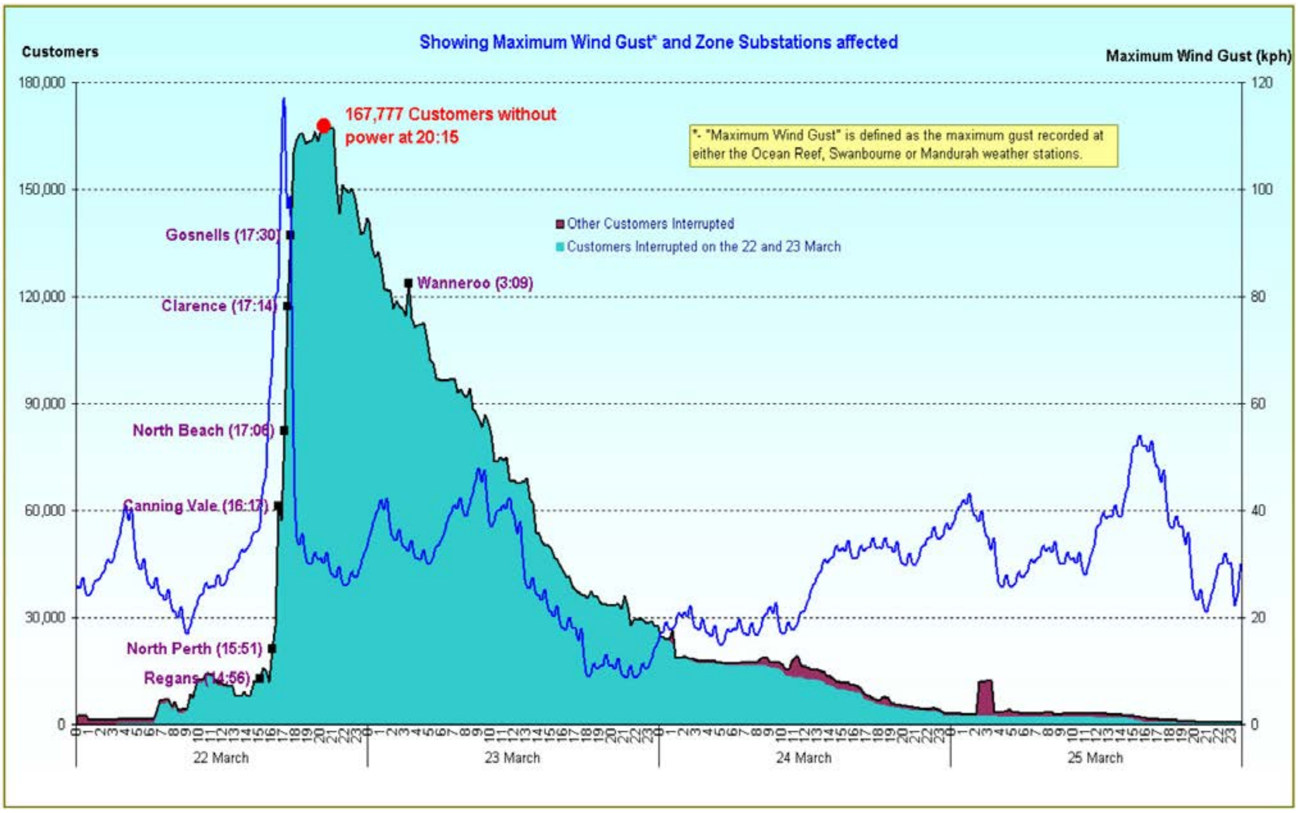

Figure 98: Number of customers affected by the March 2010 storm

Table 82 and Table 83 summarise the extent of incidents experienced by customers as a result of the March 2010 storm. This general event and incident data demonstrates the magnitude of damage to the network and resulting disruption of supply to customers.

Table 82: General event data for March 2010 storm

Category	As a result of event
Number of faults generated	4,097
Customers that experienced power loss	250,337
Customers without power for longer than 12 hours	89,602
Average outage time (minutes)	402

Table 83: Incident categories for March 2010 storm

Incident categories	Total
Power problems (No power or part power)	3,706
Wires low/down/damaged	830
Drop out fuse trips	361
Poles damaged	325

Table 84 provides information on the assets replaced and the costs incurred by asset class. The quantity and wide range of assets requiring replacement provide an indication of the severity of the storm. The cost of replacing these assets is included in the total unrecovered cost claim detailed in this section. It is important to note that none of the assets replaced in Table 84 were covered by our insurance policies.

Table 84: Asset costs from March 2010 storm

Asset	Quantity	Total cost (to nearest dollar)
Transformer	177	$719,612
Cable	46.8 km	$128,064
Pole, line construction, wood	135	$116,172
Fuse link, cartridge	9,164	$83,245
Fuse element	6,353	$74,099
Clamp	11,420	$70,505
Arrester, elect surge	385	$54,419
Wire	2 km	$38,319
Splice, conductor	11,752	$23,480
Fuseholder, base & carrier	1,090	$22,718
Bolt, machine	3,542	$21,651
Clamp, elect conductor, strain	4,219	$20,874
Terminal, lug	2,194	$19,694
Fuse cut-out, primary expulsion	949	$19,671
Insulator, strain	328	$18,683
Kit, earthing	74	$14,086
Disconnect switch, air, outdoor	66	$12,721
Insulator, standoff	129	$11,452
Joint box	82	$11,131
Distribution box	32	$10,790
TOTAL		**$1,481,192**

Description of relevant insurance

We maintain an insurance program at a quality and coverage consistent with good electricity industry practice. At all times, our insurance has reflected the level of cover available in commercial insurance markets and is of a standard of a reasonable and prudent person.

Our insurance program covers all corporate insurance exposures including property, public and products liability, motor and workers compensation, as well as other minor insurance classes. Our property insurance covers damage to physical assets including buildings, terminals and substations. Equipment other than that which is on or within 300 metres of an insured structure is not covered. The policy specifically excludes damage to transmission and distribution poles and overhead lines. All above ground transmission and distribution lines, including wire, cables, poles, pylons, towers, other supporting structures and any equipment of any type which may be attendant to such installations are not covered by an insurance policy.

Prior to 2001, we had some coverage for damage to transmission and distribution poles and overhead. However, insurers have since ceased provision of this cover and as a result we are unable to obtain insurance cover for transmission and distribution poles and overhead lines.

Unrecovered costs

We have calculated the costs directly resulting from the March 2010 storm that were not covered under any of our insurance policies.

These costs were recorded against specific work orders created for the March 2010 storm and include additional operational expenditure such as outage payments, third-party contractors engaged as a result of the event, materials procured, meals and accommodation greater than usual allowances and overtime for Western Power staff or embedded contractors. These costs are presented in Table 85.

Table 85: Unrecovered costs from March 2010 storm

Category	Costs ($ millions)
Faults/Repairs - Metro	1.98
Faults/Repairs – North Country	1.03
Faults/Repairs – South Country	0.32
Materials – unallocated	0.26
Extended outage payments	2.31
TOTAL	**5.92**

Efficient minimisation of costs

The unrecovered costs we are claiming do not exceed those which would have been incurred by a service provider efficiently minimising costs. Our procurement processes ensure the timely availability of necessary materials, such as those listed in Table 84, at market tested prices. Furthermore, we can demonstrate that our incident response processes before, during and after an incident such as the March 2010 storm are efficient and in accordance with good electricity industry practice. This includes efficient use of labour resources.

To ensure that we are prepared for a weather incident, the Network Operations Control Centre (NOCC) monitors weather conditions through resources provided by the Bureau of Meteorology. If a weather incident is imminent, NOCC operators alert the relevant fault crews and put them on standby.

After a weather incident has occurred, controllers at NOCC assume central control of the incident response. The first stage of the response is to assess the extent of the incident and the resulting damage, the availability of resources, materials, plant and equipment and the availability of distribution delivery partners' resources. This ensures the response is well planned and sufficient resources are directed to where they are most needed.

We regularly assess our fault response times and allocation of resources during a fault event. We maintain a dedicated fault information management system that time stamps all reported faults, records fault analysis and tracks the allocation of resources. This ensures that we can keep our storm and incident response practices as effective and efficient as practicable.

In assuming control of the incident response, NOCC is also charged with dispatching fault crews to fix damage to the network. In allocating fault works the preference is to mobilise our fault crews based on who is closest to the fault. When these resources run short, crews from other locations are brought in and internal crews can be taken off planned work and reassigned to fixing faults. Finally, if more resources are required, NOCC allocates external crews from our distribution delivery partners.

Our resource escalation plan requires, where possible, the allocation of internal crews to fault work before higher cost external contractors are utilised. While these crews are deployed to emergencies there may be disruptions to the normal works program, but this avoids retaining a greater number of resources at a higher cost.

Once fault crews have been dispatched, their priority is to take temporary measures to make the network safe enough to allow power supply to be restored to customers and then schedule permanent repairs to occur at a later time. This ensures that supply is restored as quickly as possible and allows permanent repairs to be completed under lower cost conditions.

We are satisfied that our storm and incident response processes ensure that we are efficiently minimising the costs incurred by these events. Therefore, the unrecovered costs, listed in Table 85, do not exceed those which would have been incurred by a service provider efficiently minimising costs.

Evidence that amount to be recovered is in addition to insurance claims

At the time of the March 2010 storm, the terms of our property insurance policy required that a deductable amount of $500,000 be paid for each and every claim. The March storm caused significant damage to our uninsured poles and wires, but only minor damage to other insured assets (eg buildings, depots, substations).

As we do not hold insurance for transmission or distribution poles or overhead wires and the total value of losses for insured assets was within our deductable amount, no claims were made against insurance policies held by the business. Therefore the unrecovered amount of $5.9 million is additional to any claims made on insurance policies.

In light of the above analysis, we seek an adjustment to target revenue for AA3, in order to recover the efficient and unrecovered costs of $6.9 million in present value terms for the March 2010 storm.

12.2.5 Technical rule changes

We are not seeking any adjustments to the target revenue for changes to the Technical Rules.

During AA2 there have been no changes to the Technical Rules that have resulted in unforeseen costs or savings to the business. None of the changes to the Technical Rules that are currently under consideration are expected to have a material impact on the expenditure in AA2.

12.2.6 D-factor

We have made no adjustment to the target revenue in relation to the D-factor provisions. We have not identified any projects that meet the criteria of the D-factor detailed in sections 5.54 to 5.57 of the current access arrangement.

The D-factor scheme has been in operation since 1 March 2010. The short period of time since it came into operation has meant that there have been limited opportunities to use the

D-factor scheme. We intend to retain this scheme for AA3. A longer access arrangement period will present more opportunities to utilise the D-factor scheme.

12.3 Working capital

We have included a return on our working capital requirements of $54 million in the target revenue. Our working capital requirements over AA3 are provided in the table below.

Table 86: Working capital - closing value

($ million real at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17
Distribution	87.6	90.1	98.2	105.5	113.2
Transmission	34.2	42.2	41.3	36.6	49.9

Working capital refers to a stock of funds that we must maintain to pay costs as they fall due. In circumstances where, on average, the costs of providing services are incurred before the revenues from provision of services are received, a stock of working capital may need to be derived from a capital investment in the business (either through debt funding or an equity injection from the shareholder).

The cost of this stock of working capital (being the required return on the capital investment) is incurred during the everyday business operation and the provision of covered services. These costs are unavoidable. The efficient financing costs, including a return on investment commensurate with the commercial risks involved, can be calculated on a forward-looking basis and incorporated within our target revenue as provided for in section 6.4 of the Access Code.

In AA1 and AA2 the Authority agreed that a return on an amount of capital investment was needed to provide for working capital and reflected the efficient costs of providing covered services.

We have adopted the same method used in AA1 and AA2 to calculate the cost of working capital for AA3. The cost of working capital for each year is determined by the working capital cycle. This cost has been calculated as the difference between the implicit cost incurred by providing credit to users of services and the implicit benefit of receiving credit from suppliers. The working capital cycle is made up of three core components:

- inventory
- accounts payable (payments due to suppliers; creditor payments)
- accounts receivable (cash due from customers; debtor collection)

The working capital cycle assumptions used for AA1 and AA2 are being maintained to determine the forward-looking and efficient amount of working capital required over AA3. The requirement for working capital is calculated within the revenue model as the difference between the sum over 45 days of the average daily covered service revenue and the sum over 20 days of the average daily expenses for the year (new facilities investment and non-capital costs). Table 87 details the assumptions applied in AA3.

Table 87: Working capital assumptions

Working capital	Days	Comment
Inventory	0	We have addressed the forward-looking efficient costs of maintaining inventory separately to determining the working capital requirements. Details on our treatment of Inventory for AA3 are provided in section 10.2.9 of this document.

Working capital	Days	Comment
Creditors	-20	Determined from an expense lead of 10 days on labour costs, an expense lead of 30 days on direct costs of materials and services and no expense lead on internal costs of materials and services or other costs. An identical assumption was adopted in AA1 and AA2.
Receivables	45	Determined from the meter reading cycles and payment terms of the electricity transfer access contract. An identical assumption was adopted in AA1 and AA2.
Prepayments	0	No working capital requirements for prepayments have been identified.

Our working capital assumptions represent an efficient cost given that:

- meter reading cycles are determined in accordance with the service level agreement for conducting a scheduled reading of the meter. The model service level agreement, approved by the Authority on 30 March 2006, provides for the majority of meters (type 6[260]) to be read on bimonthly basis using best fit schedule route optimisation. Other types of meters (type 1 to 5[261]) are read on a monthly basis
- we are retaining the existing payment terms of 10 business days detailed in the electricity transfer access contract. Payment terms of 10 business days has been accepted by the Authority as being efficient in other standard contracts, such as Goldfields Gas Pipeline[262] and WA Gas Networks Distribution System[263]
- our labour costs are generally paid in arrears on a fortnightly basis
- an average of 30 days on materials reflects terms with suppliers and is representative of those obtained in a competitive market

[260] The *Electricity Industry Metering Code 2005* defines a type 6 metering installation as an accumulation meter with less than 50 MWh annual throughput.
[261] The *Electricity Industry Metering Code 2005* defines a type 1 - 5 metering installations as an interval meter with greater than 50 MWh annual throughput.
[262] Appendix 3 – Clause 13.4, *Goldfields Gas Pipeline Final Proposed Revisions To Access Arrangement* as amended 4 June 2010.
[263] Annexure E, Clause 9.3, *Revised access arrangement for the WA Gas Networks Pty Ltd Mid-West and South-West Gas Distribution Systems*, ERA, 28 April 2011.

12.4 Tariff equalisation contribution

We have included $907 million in the AA3 target revenue for the tariff equalisation contribution (TEC). Western Power pays the TEC to the State Government to contribute towards maintaining the financial viability of Horizon Power under Part 9A of the *Electricity Industry Act 2004*. TEC is included within our target revenue in line with the requirements of sections 6.4 (a) (vii) and 6.37A of the Access Code.

> **Access Code provisions**
>
> **Section 6.37A**
>
> *If the service provider for the Western Power Network is or will be required, by a notice made under section 129D(2) of the Act, to pay a tariff equalisation contribution into the Tariff Equalisation Fund during an access arrangement period, then an amount may be added to the target revenue for the covered network for the access arrangement period, which amount—*
>
> *a) must not exceed the total of the tariff equalisation contributions which are or will be required to be paid under the notice, including any amount that was payable or paid before the commencement of the access arrangement period; and*
>
> *b) must be separately identified as being under this section 6.37A.*

The purpose of the TEC is to enable the regulated retail tariffs for electricity that is not supplied from the south west interconnected system (SWIS) to be, so far as is practicable, the same as the regulated retail tariffs for electricity that is supplied from the SWIS.

Section 6.37A and 7.12 of the Access Code enable the TEC to be recovered from users the distribution network. We will recover the TEC from distribution customers with demand less than 7,000 kVA. Customers with demand greater than 7,000 kVA do not pay TEC. This is because these customers can usually choose between being connected to the transmission or the distribution network. Charging TEC to distribution-connected users with demand greater than 7,000 kVA may create an incentive for those users to change to being connected to the transmission network in order to avoid being charged for the TEC. A high number of customers switching from the distribution to the transmission network could result in additional costs that would ultimately be paid for by the wider customer base.

The State Government periodically gazettes the TEC amounts. Given the potential changes that may occur to TEC over the five years of AA3, the price control formula for the distribution system includes an explicit pass-through element for TEC.

Our TEC forecast over the AA3 period aligns with the TEC forecast in the State Budget and is detailed in Table 88. At the time of this submission the TEC requirements for the AA3 period has not been gazetted by the Government. We have assumed that TEC grows in line with inflation over AA3.

Table 88: Tariff equalisation contributions forecasts over AA3

($ million real at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17
Tariff equalisation contributions	181.2	180.7	180.8	181.7	182.5

12.5 Deferred revenue

We will recover all revenue deferred from AA2 in the AA3 period.

During the AA2 review process, $548.7 ($ million real at 30 June 2009) million of revenue was deferred for collection until a later date. This was done to reduce the impact on prices to customers during the AA2 period resulting from the change in the treatment of capital contributions in the determination of target revenue.[264]

[264] For AA2, we changed our treatment of capital contributions from the Queensland method to a conventional regulatory methodology. Under the Queensland method, gross capital expenditure (inclusive of capital contributions) was rolled into our capital base with the costs associated with

12.5.1 Deferred revenue timing and recovery method

We will recover all of the deferred revenue as a real annuity over the five years of the AA3 period. By taking account of inflation and the time value of money, our method of recovery meets the requirements of section 5.37A and 5.48A of the current (AA2) access arrangement.

NERA Economic Consulting has previously advised Western Power on the benefits associated with the change in capital contribution policy that occurred in AA2.[265] The benefits included improved financial sustainability through higher cash flows, improved intergenerational equity and improved price signals. The deferral of AA2 revenue has meant that none of these benefits from the change in contributions policy have been realised in AA2. The recovery of the deferred revenue over the AA3 period will ensure that these benefits will be realised.

Recovering all deferred revenue during the AA3 period meets the Access Code objective by:

- avoiding equity raising costs in AA3. Avoiding equity raising costs represents a real cost saving to customers
- improving inter-generational equity as future users are not paying for assets used by current users

We do not consider that the recovery of all of the deferred revenue as a real annuity causes price shock during AA3. The price path adopted over the AA3 period results in average price increases that are equal to or lower than the recent average price increases over AA2.[266]

12.5.2 Value of deferred revenue

In accordance with section 5.37A and 5.48A of the current access arrangement and section 6.5C of the Access Code, the value of the deferred revenue to be collected during AA3 has been adjusted to take into account inflation and the time value of money over the AA2 period of deferred recovery.

Table 89 details the impact of these adjustments on the value of the deferred revenue at the beginning of the AA3 period.

Table 89: Value of deferred revenue at the start of AA3

	Opening value of deferred revenue detailed in the Authority's Final Decision[267] ($ million real at 30 June 2009)	Estimated opening value of deferred revenue at the start of AA3 ($ million real at 30 June 2012)
Distribution	484.2	667.2
Transmission	64.5	88.8
Total	**548.7**	**756.0**

contributed works amortised over the life of the asset. Under the new (conventional) approach, net capital expenditure (exclusive of capital contributions) is to be rolled into our capital base at the beginning of the next access arrangement period. Refer to paragraph 995 of the *ERA's Final Decision* (4 December 2009).

[265] Attachment J, *ERA Required Amendments 32 and 36: Deferral of Target Revenue from AA2 to AA3 and Beyond*, NERA Economic Consulting, 1 September 2009.

[266] The average price path for AA3 is discussed in 13.3 of this document.

[267] Paragraph 996, *Final Decision on the Proposed Access Arrangement for the South West Interconnected Network*, ERA, 4 December 2009.

The value of deferred revenue reflects forecast inflation for the year ending 30 June 2012. At the time of preparing these proposed access arrangement revisions inflation for the year ending 30 June 2012 is forecast as 2.50%.

At the next access arrangement review an adjustment will be made to the AA4 target to compensate Western Power (or users) for the revenue foregone (or additional revenue recovered) over the forthcoming access arrangement period in respect of the differences between the actual and forecast inflation for the 2011/12 financial year.

12.6 Capital contributions tax costs

We have included $240 million in the target revenue to cover the net tax costs associated with forecast capital contributions and gifted assets provided by customers. The tax cost is approximately 25% of the forecast capital contributions and gifted assets provided by customers.

The tax costs arise due to the timing differences in the tax paid on receipt of the capital contributions and gifted assets and the depreciation tax shield provided over the life of the assets.[268] These tax costs are material given the magnitude of the capital contributions and gifted assets we receive.

During AA1 we were able to recover these costs implicitly through the pre-tax WACC due to the value of capital contributions and gifted assets being added to the capital base.

The treatment of capital contributions changed in AA2 and they are no longer added to the capital base. During AA2 we have not recovered any associated tax costs from customers. This has resulted in the shareholder bearing all these costs. This is inconsistent with section 6.4(a)(i) of the Access Code, which provides for target revenue to include forward-looking and efficient costs of providing covered services. These tax costs are material and cannot be influenced by us as they result from the application of the tax equivalence scheme and choices made by customers when connecting to the network.

The calculation of the tax costs for AA3 takes account of the:

- circularity arising from the revenue and tax impact of recovering the tax costs
- dividend imputation franking credits passed through to our shareholder
- statutory tax depreciation benefit which offsets the tax costs incurred later years

Circularity arises because a customer's payment of tax costs is treated as revenue. This increases the value of revenue that is taxed. This in turn requires the payment of additional tax, which further increases the revenue amount and attracts additional tax and so on. Appropriately recognising this circularity and using our marginal tax rate of 30%, the total tax cost equals 42.86% of the initial capital contribution or gifted asset value. However, our dividend imputation franking credit and statutory tax depreciation benefits partially offset this amount.

The calculation of the tax costs includes the assumed benefit that dividend imputation franking credits[269] provide to our shareholder. We adopt an identical assumption on the value of dividend imputation franking credits as used to determine our WACC to ensure

[268] This occurs because capital contributions and gifted assets are treated as revenue by the accounting standards applicable to Western Power - *Australian Accounting Standards Board, Interpretation 18 "Transfer of Assets from Customers"*, March 2009, available from: http://www.aasb.gov.au/admin/file/content105/c9/INT18_03-09.pdf

[269] Dividend imputation attributes franking credits, for the tax paid by a company, to the company's shareholders by way of a tax credit to reduce the shareholder's income tax payable. Franking credits represent the company tax already paid to ensure that distributed company profits are only taxed once at the shareholder's tax rate.

consistency (see section 11.4.6 of this document). This assumption decreases our effective tax rate from the statutory tax rate of 30% and reduces tax costs from 42.86% to 29.03%.

We also derive benefit from the statutory tax treatment of the depreciation expense associated with the capital contribution or gifted assets. The statutory tax depreciation expense offsets our taxable revenue. This creates a tax shield which further reduces tax costs.[270]

Incorporating the benefits of both franking credits and the tax shield reduces our tax costs to a grossed up tax expense of approximately 25% of the initial capital contribution or gifted asset value. The capital contribution transmission costs that are included in the AA3 target revenue are provided in Table 90. These are based on the forecasts of capital contributions and gifted assets that are provided in chapter 8 of this document.

Table 90: Capital contribution tax costs

($ million real as at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17
Distribution	41.6	37.9	35.1	35.3	36.0
Transmission	10.6	10.7	10.9	11.0	11.4

12.7 AAI Guidelines provisions

Section 4.6.4 of the AAI Guidelines specifies the information that must be in this AAI regarding the adjustment to target revenue due to the gain sharing mechanism. Table 91 details the requirements of the guidelines with a cross reference to the relevant section of this AAI.

Table 91: AAI Guidelines compliance for the gain sharing mechanism

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.6.4	*Where an adjustment to target revenue is to be made under section 6.27 of the Access Code, the access arrangement information must include:* • *details of how the adjustment to target revenue has been calculated*	Section 12.2.1
4.6.4	• *evidence that the benchmark and actual non-capital costs have been adjusted to ensure that a like-for-like comparison is made, and that efficiency improvements are measured appropriately*	Section 12.2.1
4.6.4	• *if relevant, evidence to show that service targets were achieved*	Section 12.2.1

Section 4.6.3 of the AAI Guidelines specifies the information that must be in this AAI regarding the adjustment to target revenue due to the investment adjustment mechanism.

[270] The 3.5% – 4.0% tax shield calculation is based on the existence of franking credits (which reduces the ‘effective’ tax rate) and incorporates discounting based on Western Power’s WACC for the AA3 period of 8.82%. Any change to the value of the WACC will vary the calculation of the tax shield percentage and influence the grossed up tax expense calculation of 24.98% to 25.56%.

Table 92 details the requirements of the guidelines with a cross reference to the relevant section of this AAI.

Table 92: AAI Guidelines compliance for the investment adjustment mechanism

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.6.3	*the access arrangement information must include* • *details of how the adjustment to target revenue has been calculated*	Section 12.2.3
4.6.3	• *comparison of the assumptions underlying the original forecasts (for example, growth in demand or number of new connections) with the actual results and the impact on expenditure*	Section 12.2.3
4.6.3	• *evidence that the amount to be recovered through an adjustment to target revenue does not exceed the costs which would have been incurred by a service provider efficiently minimising costs*	Section 3.7 and 10.2.2
4.6.3	• *if relevant, evidence that service targets were achieved*	N/A

Section 4.6.5 of the AAI Guidelines specifies the information that must be in this AAI regarding the adjustment to target revenue due to the service standards adjustment mechanism. Table 93 details the requirements of the guidelines with a cross reference to the relevant section of this AAI.

Table 93: AAI Guidelines compliance for the service standards adjustment mechanism

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.6.5	*Where an adjustment to target revenue is to be made under section 6.29 of the Access Code, the access arrangement information must include:* • *details of how the adjustment to target revenue has been calculated*	Section 12.2.2
4.6.5	• *evidence to support the reported performance measures*	Section 3.2
4.6.5	• *evidence that the calculation complies with the approved mechanism in the current access arrangement*	Section 12.2.2

Section 4.6.1 of the AAI Guidelines specifies the information that must be in this AAI regarding the adjustment to target revenue due to unforeseen events. Table 94 details the requirements of the guidelines with a cross reference to the relevant section of this AAI.

Table 94: AAI Guidelines compliance for the cost recovery for unforeseen events

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.6.1	*Where an adjustment to target revenue is to be made under section 6.6 of the Access Code, the access arrangement information must include:* • *descriptions of relevant force majeure events*	Section 12.2.4
4.6.1	• *for each force majeure event, description and justification that the service provider held relevant insurance to the standard of a reasonable and prudent person*	Section 12.2.4
4.6.1	• *for each force majeure event, amount, or forecast amount, of unrecovered costs sought to be recovered through an adjustment to target revenue*	Section 12.2.4
4.6.1	• *evidence that the amount to be recovered through an adjustment to target revenue is an amount that does not exceed the costs which would have been incurred by a service provider efficiently minimising costs*	Section 12.2.4
4.6.1	• *evidence that the amount to be recovered through an adjustment to target revenue is an amount in addition to any amount that is recoverable through a claim on an insurance policy*	Section 12.2.4

13 Total target revenue, price path and annual revenue caps

This chapter details Western Power's target revenue and the revenue caps for the reference services for the AA3 period.

13.1 Key messages:

- The target revenue for AA3 is $10.329 billion ($7.524 billion for distribution revenue cap services and $2.805 billion for transmission revenue cap services)
- The average price path is a 16.4% increase in the first year and approximately 11% per year thereafter.

13.2 Target revenue

We have calculated target revenue with reference to approved total costs, as provided for in section 6.2(a) of the Access Code, by applying the building blocks methodology. We have determined target revenue separately for the transmission system and the distribution system. This section brings together the building blocks of the target revenue for the transmission and distribution networks.

The objectives of the price control in an access arrangement are to provide the network service provider (Western Power) with an opportunity to earn revenue for the access arrangement period from the provision of covered services. Forecast target revenue for the AA3 period is calculated in accordance with section 6.4 of the Access Code.

Access Code provisions

Section 6.4(a) defines 'target revenue' as**:**

i. *an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;*

plus:

ii. *for access arrangements other than the first access arrangement, an amount in excess of the revenue referred to in section 6.4(a)(i), to the extent necessary to reward the service provider for efficiency gains and innovation beyond the efficiency and innovation benchmarks in a pervious access arrangement;*

plus

iii. *an amount (if any) determined under section 6.6*

plus

iv. *an amount (if any) determined under section 6.9;*

plus

v. *an amount (if any) determined under an investment adjustment mechanism (see sections 6.13 to 6.18)*

plus

vi. *an amount (if any) determined under a service standards adjustment mechanism (see sections 6.29 to 6.32);*

plus

vii. *an amount (if any) determined under section 6.37A*

A number of the adjustments to target revenue are applied in the first year of AA3. Section 13.3 describes our approach to smoothing the revenue over the AA3 period, which will address any variation in revenue due to these adjustments.

In addition, our current access arrangement (for the AA2 period) provides for the following matters to be taken into account in the determination of target revenue for the AA3 period:

- section 5.37 of the current access arrangement provides for the correction factor, TK_t, to apply in the first year of the AA3 period. This adjusts for any difference between maximum regulated transmission network revenue and actual transmission network revenue, in relation to the financial year 1 July 2011 to 30 June 2012

- section 5.37A of the current access arrangement provides for the recovery of the transmission revenue that was deferred from the AA2 period into the AA3 and subsequent periods. Our approach to the recovery of the deferred revenue is detailed in section 12.5.1 of this document
- section 5.48 of the current access arrangement provides for the correction factor, DK_t, to apply in the first year of the AA3 period. This adjusts for any difference between maximum regulated distribution network revenue and actual distribution network revenue, in relation to the financial year 1 July 2011 to 30 June 2012
- section 5.48A of the current access arrangement provides for the recovery of the distribution revenue that was deferred from the AA2 period into the AA3 and subsequent periods. Our approach to the recovery of the deferred revenue is detailed in section 12.5.1 of this AAI document
- section 5.54 – 5.57 of the current access arrangement provides for the D-factor scheme. The adjustment to the AA3 target revenue is detailed in section 12.2.6

Table 95 and Table 96 presents the AA3 target revenue.

Table 95 shows the composition of the transmission network revenue for AA3. Further detail of the modelling is set out in Appendix F: Revenue model summary.

Table 95: Composition of transmission network target revenue[271]

($ million real at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17	Present value
Operating expenditure	125.0	122.5	132.3	142.4	156.3	525.0
Plus depreciation	91.2	100.9	109.2	117.8	129.6	422.7
Plus redundant assets	0.0	0.0	0.0	0.0	0.0	0.0
Plus return on investment	250.6	273.6	289.0	311.0	346.8	1,134.7
Plus return on working capital	1.2	3.0	3.7	3.6	3.2	11.3
Plus tax costs due to capital contributions	10.6	10.7	10.9	11.0	11.4	42.5
Forward-looking efficient costs	**478.5**	**510.7**	**545.2**	**585.9**	**647.4**	**2,136.2**
Plus gain sharing mechanism	0.0	0.0	0.0	0.0	0.0	0.0
Plus unforeseen events adjustment	0.0					0.0
Plus Technical Rules change adjustment	0.0					0.0
Plus investment adjustment mechanism amount	-47.4					-43.6
Plus service standards adjustment mechanism amount	-0.7					-0.7
Plus D-factor amount	0.0					0.0
Plus recovery of AA2 deferred revenue	22.7	22.7	22.7	22.7	22.7	88.8
Adjustments in accordance with previous access arrangement	**-25.5**	**22.7**	**22.7**	**22.7**	**22.7**	**44.5**
Plus TK_t[272]	0.0	0.0	0.0	0.0	0.0	0.0
Less non-revenue cap services revenue	3.1	3.2	3.4	3.6	3.9	13.3
Transmission target revenue for revenue cap services (unsmoothed)	**449.9**	**530.3**	**564.5**	**605.1**	**666.2**	**2,167.4**

[271] We allocate our corporate capital expenditure between the transmission system and distribution system in accordance with the method set out in the cost and revenue allocation methodology attached at Appendix E.

[272] TK_t will be calculated each year in accordance with the access arrangement to support the Authority's approval of the price list

Table 96 shows the composition of the distribution network revenue for AA3. Further detail of the modelling is set out in Appendix F: Revenue model summary.

Table 96: Composition of distribution network target revenue[273]

($ million real as at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17	Present Value
Operating expenditure	371.4	387.4	408.3	420.1	447.9	1,578.3
Plus depreciation	206.7	226.9	250.8	255.7	270.2	935.7
Plus redundant assets	3.4	0.5	0.0	0.0	0.0	3.6
Plus return on investment	375.5	407.0	444.3	480.9	514.4	1,713.6
Plus return on working capital	5.1	7.7	8.0	8.7	9.3	29.7
Plus tax costs due to capital contributions	41.6	37.9	35.1	35.3	36.0	136.2
Forward-looking efficient costs	**1,003.7**	**1,067.4**	**1,146.4**	**1,200.7**	**1,277.8**	**4,407.0**
Plus gain sharing mechanism	0.0	0.0	0.0	0.0	0.0	0.0
Plus unforeseen events adjustment	7.5					6.9
Plus Technical Rules change adjustment	0.0					0.0
Plus investment adjustment mechanism amount	2.0					1.8
Plus service standards adjustment mechanism amount	3.1					2.8
Plus D-factor amount	0.0					0.0
Plus recovery of AA2 deferred revenue	170.7	170.7	170.7	170.7	170.7	667.2
Adjustments in accordance with previous access arrangement	**183.3**	**170.7**	**170.7**	**170.7**	**170.7**	**678.7**
Tariff equalisation contribution – TEC_t	181.2	180.7	180.8	181.7	182.5	708.6
Plus DK_t[274]	0	0	0	0	0	0
Less non-revenue cap services revenue	14.9	15.3	16.0	16.8	17.9	62.8
Distribution target revenue for revenue cap services (unsmoothed)	**1,353.3**	**1,403.5**	**1,481.9**	**1,536.3**	**1,613.2**	**5,731.6**

[273] We allocate our corporate capital expenditure between the transmission system and distribution system in accordance with the method set out in the cost and revenue allocation methodology attached at Appendix E.
[274] DK_t will be calculated each year in accordance with the access arrangement to support the Authority's approval of the price list.

13.3 Average price path

We have translated the target revenue for revenue cap services into an average price path and annual revenue cap. The price path is determined by smoothing the revenue over the period whilst retaining the net present value of the total target revenue. The smoothed revenue in any year may not reflect the underlying building block components of that year, however the total value of revenue is retained over AA3 in present value terms. This smoothed revenue profile may be affected by the following:

- forecast energy consumption over AA3[275]
- the average price path over AA2
- predictable changes in average price during the AA3 period

It is normal regulatory practice to adjust the building blocks target revenue to enable a more predictable (and less volatile) price path by smoothing the revenue. Smoothing is required because the target revenue calculated through the building block methodology may result in the revenue moving up or down throughout the period.

The smoothing process benefits customers by providing greater visibility of future pricing and avoiding price shocks. Smoothing ensures that, in present value terms, over the course of the access arrangement period target revenue is equivalent to the sum of the revenue cap allowed in each year.

In AA2, we smoothed the revenue cap based on a price path with constant increases in average tariffs across all pricing years of the period, including the first. On a weighted average basis the real increase in average tariffs over AA2 was 16.3% each year.

[275] Energy forecasts for AA3 are detailed in chapter 6 of this document.

Transmission reference tariffs

In AA3, we propose smoothing the revenue cap based on a price path that continues the AA2 real increase in the average transmission reference tariff of 12.9% for a further year followed by real increases of 4.5% for the remaining pricing years of the period. Figure 99 details the average price path for transmission reference tariffs over the AA3 period.

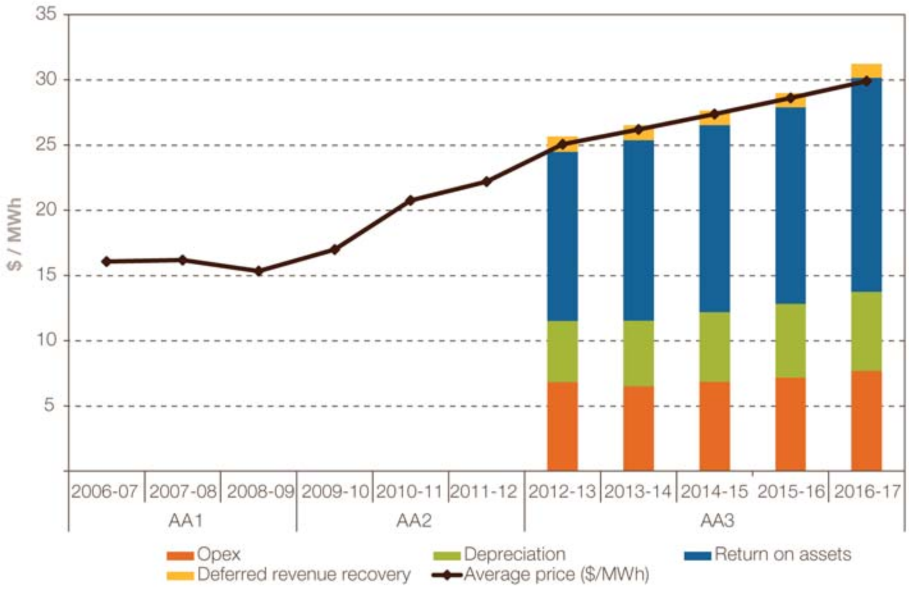

Figure 99: Average transmission reference tariff price path

Distribution reference tariffs

In AA3, we propose smoothing the revenue cap based on a price path that is consistent with the AA2 real increase in average distribution tariffs (16.3%) for the first year only. The AA3 real increase in average distribution reference tariff is 16.4% for the first year, followed by real increases of approximately 11% in average tariffs across the remaining pricing years of the period.[276] Figure 100 details the average price path for distribution reference tariffs over the AA3 period.

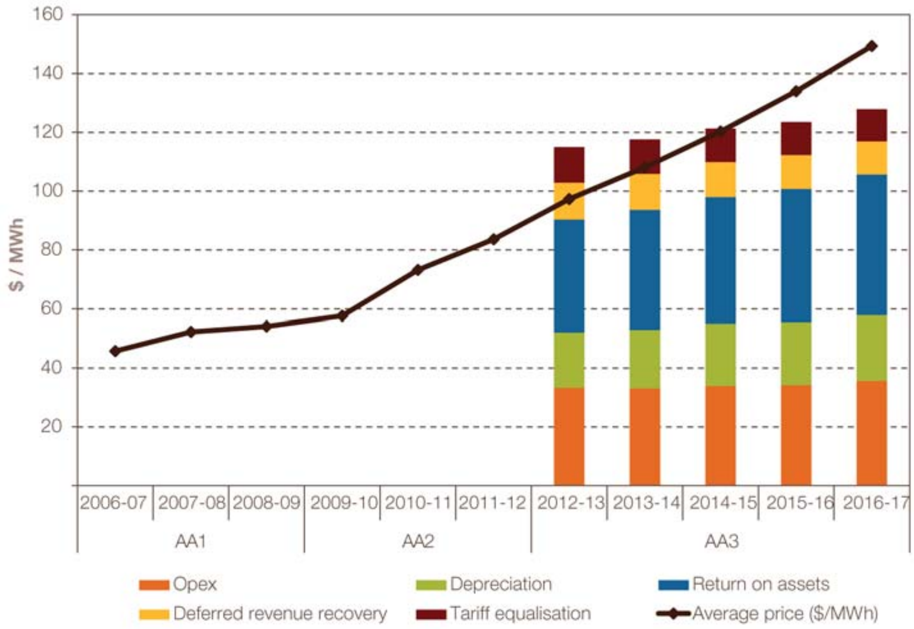

Figure 100: Average distribution reference tariff price path

Table 97 summarises the expected average proportional changes in reference tariffs for users of the Western Power Network from one pricing year to the next during AA3.

Table 97: Average price path over AA3 – presented in real terms

Pricing year commencing	1 July 2012	1 July 2013	1 July 2014	1 July 2015	1 July 2016
Transmission reference tariffs	12.9%	4.5%	4.5%	4.5%	4.5%
Distribution reference tariffs	16.4%	11.1%	11.2%	11.4%	11.5%

The network tariffs are only one component of retail tariffs. If, for example, the network tariff comprises half the retail tariff, the percentage increase in retail tariff as a result of the increase in network tariffs will be half the percentage increase in the network tariff.

Additionally, the extent of any change in the retail tariff paid by customers as a result of these annual changes in network tariffs will differ between non-contestable customers and

[276] The increases in the average distribution reference tariff reflect the “bundled” tariff outcome (the combined effect of the movements in the transmission and distribution components). The transmission components and distribution components will increase by different amounts with the resultant average outcome as detailed in Table 97.

contestable customers. Non-contestable customers are supplied by Synergy and may be eligible for retail tariffs prescribed in the *Energy Operators (Electricity Retail Corporation) (Charges) By-laws 2006* (as amended). Any increases in these retail tariffs are determined by the State Government and may not reflect the increases in the network tariffs.

The current state government budget planning assumption for retail tariffs is for a 5% increase in 2012/13 followed by 12% increases in 2013/14 and 2014/15. The retail tariff for contestable customers is generally set by the retailer. It is expected that retailers will seek to recover any increases in the network tariffs from these customers.

Note that changes to individual reference tariffs may vary by more or less than the average tariff changes. Changes to individual reference tariffs during the AA3 period are constrained by a side-constraint which is discussed further in section 15.5 of this document.

13.4 Annual revenue cap

The revenue to be recovered under the revenue cap for each year of the AA3 period reflects the target revenue and the average price path. The value for each year must be identified when applying the price control formula. The present value of the revenue determined under the price control formula is equivalent to the target revenue detailed in Table 95 and Table 96.

The price control formula for the **transmission** system is:

$$\mathbf{MTR_t = TR_t + AA2_t + TK_t}$$

We have calculated the TR_t parameter by assuming that the $AA2_t$ and TK_t parameters are zero. Our reasons for these assumptions are:

- the $AA2_t$ parameter provides for an adjustment to give effect to the various incentive and adjustment mechanisms from AA2, however we have incorporated these adjustments into the calculation of TR_t (see Table 95). We may use the $AA2_t$ parameter to make adjustments in the future to correct for any variances between forecast and actuals for the various incentive and adjustment mechanisms from AA2
- the TK_t parameter is a correction factor for differences in revenue collected by us and the revenue cap. In calculating TR_t we have assumed that we collect the revenue cap in the year that it is due

Table 98 details the TR_t annual parameters for AA3:

Table 98: Transmission smoothed annual revenue)

($ million real at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17	Present Value
Annual revenue cap services revenue – TR_t	486.5	523.7	559.2	597.3	638.2	2,167.4
% change in TR_t		7.6%	6.8%	6.8%	6.8%	

We have amended the formula used to calculate TK_t to clarify our practice of using a forecast of actual revenue when setting prices due to the timing of the annual price list approval. The amended formula corrects for any differences between the actual and the forecast in the following year. This reflects our current approach in calculating the correction factor.

Further detail on the revenue cap for the transmission system is in section 5.6 of the proposed access arrangement.

The price control formula for the **distribution** system is:

$$MDR_t = DR_t + TEC_t + AA2_t + DK_t$$

We have calculated the DR_t parameter by using our forecasts for TEC_t and assuming that the $AA2_t$ and DK_t parameters are zero. Our reasons for these assumptions are:

- the TEC_t parameter is an explicit pass-through element to recover the gazetted amounts of TEC. To ensure a smooth price path the TEC forecast is included within the target revenue when setting the price path. We have used our forecasts for TEC in calculating the DR_t parameter
- the $AA2_t$ parameter provides for an adjustment to give effect to the various incentive and adjustment mechanisms from AA2, however we have incorporated these adjustments into the calculation of DR_t (see Table 96). We may use the $AA2_t$ parameter to make adjustments in the future to correct for any variances between forecast and actuals for the various incentive and adjustment mechanisms from AA2
- the DK_t parameter is a correction factor for differences in revenue collected by us and the revenue cap. In calculating DR_t we have assumed that we collect the revenue cap in the year that it is due

Table 99 details the derivation of the DR_t annual parameters for AA3:

Table 99: Distribution smoothed annual revenue

($ million real at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17	Present Value
Annual revenue cap services revenue	1,084.8	1,262.5	1,469.9	1,712.2	1,994.3	5,731.6
Less TEC_t[277]	181.2	180.7	180.8	181.7	182.5	708.6
Distribution revenue cap formula component – DR_t	903.7	1,081.7	1,289.1	1,530.5	1,811.8	5,023.0
% change in DR_t		19.7%	19.2%	18.7%	18.4%	

We have amended the formula used to calculate DK_t to clarify our practice of using a forecast of actual revenue when setting prices due to the timing of the annual price list approval. The amended formula corrects for any differences between the actual and the forecast in the following year. This reflects our current approach in calculating the correction factor.

We have amended the quarter applicable for the CPI calculation to convert the revenue cap into nominal dollars to use the December quarter. The timing of the price list annual submission is generally earlier than when the Australian Bureau of Statistics publishes the March quarter CPI data. To resolve this timing issue we have amended the access arrangement to apply the December quarter CPI data.

13.5 AAI Guidelines provisions

The requirements regarding target revenue are detailed in section 4 of the AAI Guidelines

Table 100 details the requirements with a cross reference to the relevant section of this AAI.

[277] The price control formula for the distribution system includes an explicit pass through element for TEC.

Table 100: AAI Guidelines compliance for the target revenue

AAI Guidelines section #	AAI Guidelines wording	Cross reference
4.1	*Where target revenue is set in whole or in part by the first of these methods [where target revenue is set by reference to the service provider's approved total costs], the information supporting the proposal for target revenue must include forecasts of costs and information in support of these forecasts.*	Chapter 7, chapter 8, section 10.3.3 and chapter 11
4.2	*Information supporting a target revenue proposal is required to assist in understanding the determination of the amount of target revenue and an assessment of whether the amount of target revenue complies with the requirements of the Access Code.*	Section 13.2

Part D: Regulatory framework

14 Incentive mechanisms

This chapter sets out the various incentive and adjustment mechanisms guiding performance for the AA3 period, which will be taken into account when establishing the target revenue for AA4, including:

- the service standards adjustment mechanism
- the gain sharing mechanism
- the investment adjustment mechanism
- the D-factor scheme
- the mechanism for adjusting the target revenue for unforeseen events
- the mechanism for adjusting the target revenue for Technical Rules changes
- trigger events

14.1 Key messages

- We propose a number of changes to the service standards adjustment mechanism (SSAM) to improve the effectiveness of the mechanism and the strength of incentives for performance improvements.
- We will retain the current form of the gain sharing mechanism (GSM) with some changes to ensure that it is focussed on costs within our control.
- We will retain the current form of the investment adjustment mechanism (IAM).
- We will retain the current form of the D-factor and clarify the project list to which it can apply.
- We will update the list of potential unforeseen events and trigger events.
- We are not changing the Technical Rules change provision.

14.2 Service standards adjustment mechanism

We are proposing a number of changes to the SSAM for AA3. This includes setting the financial incentive targets at a level that reflects the expected level of performance, comparable with the performance customers have experienced over the last five years. The revisions also include adjusting the incentive rates to reflect a proxy for the value to customers of service improvements and deterioration and changing the formula to calculate the SSAM adjustment so that the incentive to improve performance is not distorted.

Our revisions will improve the effectiveness of the mechanism so that it provides stronger incentives for performance improvements.

The reasons for the revisions and the methodology used to establish the targets and financial penalties are provided in sections 5.5 and 5.6 of this document.

The impact of this adjustment mechanism will be taken into account when establishing the target revenue for AA4.

14.3 Gain sharing mechanism

We will retain the current form of the gain sharing mechanism (GSM) for AA3 with a number of adjustments. The adjustments are to:

- exclude a number of costs that are outside our control from the efficiency and innovation benchmark and the calculation of the above-benchmark surplus
- introduce an ex-post growth adjustment to the efficiency and innovation benchmark when calculating the above-benchmark surplus for the AA3 period
- adjust the above-benchmark surplus formula to cater for the five-year length of AA3

Access Code provisions

A gain sharing mechanism is defined in **sections 6.19** to **6.21** of the Access Code.

Section 6.19(a)

A "gain sharing mechanism" is a mechanism:

> *in an access arrangement which is applied at the next access arrangement review to determine an amount to be included in the target revenue for one or more of the following access arrangement periods.*

Section 6.20

an access arrangement must contain a gain sharing mechanism unless the Authority determines that a gain sharing mechanism is not necessary to achieve the objective in section 6.4(a)(ii).

Section 6.21

A gain sharing mechanism must have the objective of:

a) achieving an equitable allocation over time between users and the service provider of innovation and efficiency gains in excess of efficiency and innovation benchmarks; and

b) being objective, transparent, easy to administer and replicable from one access arrangement to the next; and

c) giving the service provider an incentive to reduce costs or otherwise improve productivity in a way that is neutral in its effect on the timing of such initiatives.

The GSM provides an additional incentive to reduce operating expenditure or otherwise improve productivity, with rewards carried over into future access arrangement periods. The rewards available under the GSM are calculated by comparing the efficiency and innovation benchmark against our actual operating expenditure performance (this is known as the above-benchmark surplus) and then providing this reward for a five-year period. Our efficiency and innovation benchmark is based on forecast operating expenditure, adjusted for costs that are outside our control.

The impact of this mechanism will be taken into account when establishing the target revenue for AA4.

The following sections explain the rationale for each of these changes.

14.3.1 Excluding costs outside our control

The objective of the GSM, detailed in section 6.21 of the Access Code, is to provide an incentive to efficiently reduce operating expenditure. Rewards under the GSM should result from achieving efficiencies in the operating costs that we manage. During AA2 the following operating costs were effectively excluded from the calculation of the above benchmark surplus in the GSM on the basis that they were outside our control:

- operating expenditure incurred in accordance with the D-factor
- operating costs associated with unforeseen events
- operating costs associated with changes to the Technical Rules

By removing costs that we cannot manage, the GSM will more appropriately provide incentives in relation to controllable costs.

For the AA3 period, in addition to the above, we will exclude the following from the efficiency and innovation benchmark and the calculation of the above-benchmark surplus in the GSM:

- superannuation costs for defined benefit schemes
- costs associated with non-revenue cap services
- licence fees and the Energy*Safety* levy

All of these costs are not able to be managed by us. This approach is consistent with the treatment for other regulated utilities. For example, in the AER's 2010 final decision for the Victorian electricity distributors[278] the AER identified a number of uncontrollable costs that should be excluded from the calculation of the efficiency benefit sharing scheme (which operates similarly to the GSM).

The reasons for the exclusion of these costs are provided in the following sections.

Superannuation costs for defined benefit schemes

We have no ability to affect the costs associated with superannuation for employees in a defined benefit scheme.

We have a large number of employees that are members of defined benefit superannuation schemes. The actual cost incurred each year as a result of defined benefit schemes are affected by the performance of the superannuation fund.

In other jurisdictions, costs associated with defined benefit superannuation schemes are excluded from the efficiency benefit sharing scheme (EBSS) on the basis that they are uncontrollable costs. The AER has noted:

> *…many DNSP (distribution network service provider) employees are members of a defined benefit superannuation scheme. Consequently, a DNSP's superannuation liabilities relating to these employees are affected by, among other things, the number of employees that retire in a given year, and the performance of the superannuation fund. Given that DNSPs have limited control over both of these factors, the AER considers it reasonable that the approved amount of superannuation costs for defined benefits and retirement schemes be excluded from the EBSS.*[279]

Consistent with the reasoning, we will exclude the costs of defined benefit superannuation schemes from the operation of the GSM by excluding them from the AA3 efficiency and innovation benchmark and the calculation of the above-benchmark surplus. Costs associated with *accumulation* superannuation schemes *will be included* in the GSM.

Non-revenue cap services costs

We will exclude the costs of non-revenue cap services from the operation of the GSM because these costs are dependent on the requirements of the customer. We recover the costs of providing these services directly from the customers to whom the service is provided.

The customer-driven nature of non-revenue cap services means that the operating costs will vary from the forecasts. For example, if we had forecast to undertake 100 units of an activity but were subsequently required to undertake 200 units to meet increased customer demands, costs would be increased and so would revenue. Similarly if customer demand was lower, then costs and revenue will be lower.

[278] *Final decision Victorian electricity distribution network service providers Distribution determination 2011–2015*, AER, October 2010.
[279] p608, *Draft decision Victorian electricity distribution network service providers Distribution determination 2011–2015*, AER, June 2010; and
p655, *Final decision Victorian electricity distribution network service providers Distribution determination 2011–2015*, AER, October 2010.

If these costs were subject to the GSM it would provide increased incentive to reduce these costs, which could potentially result in a conflict with the need to respond appropriately and effectively to customers' requirements.

We will exclude the costs of non-revenue cap services from the operation of the GSM by excluding them from the AA3 efficiency and innovation benchmark and the calculation of the above-benchmark surplus.

Fees and the Energy*Safety* levy

We are unable to influence licence fees and the Energy*Safety* levy[280]. Licence fees are set by the Electricity Industry (Licensing Fees) Regulations 2005. Similarly, the Energy*Safety* levy is set by Energy*Safety*.

Therefore any difference between actual and forecast cost should not impact on any efficiency benefits that we may obtain under the GSM. We will exclude these fees and levies from the operation of the GSM by excluding them from the AA3 efficiency and innovation benchmark and the calculation of the above-benchmark surplus.

The exclusion of these fees and levies is consistent with the approach adopted elsewhere. The AER allows for licence fees to be recovered as an explicit component of the price control formula through the licence fee (L_t) factor for the Victorian businesses and is excluded from the efficiency benefit sharing scheme.

14.3.2 Ex-post growth adjustment when calculating the above-benchmark surplus from the AA3 period

As we have included scale escalation in our forecast operating expenditure for AA3, we propose a growth adjustment to the GSM calculation. This involves substituting the forecast scale factors used to derive the efficiency and innovation benchmark for AA3 with the **actual** scale factors when calculating the above-benchmark surplus at the end of AA3. The scale escalation methodology and the associated factors used to determine forecast operating expenditure for AA3 are detailed in section 7.2 of this document.

We should not be rewarded or penalised for variations from forecast operating expenditure that are attributable to differences in the scale factors driving expenditure (such as customer numbers, line length, number of feeders or zone substation capacity). Conversely, customers should not pay more under the GSM because of slower growth.

Similar to the concept of removing uncontrollable costs, or having an investment adjustment mechanism, a growth adjustment would ensure that only efficiency gains that are attributable to business decisions are rewarded through the GSM.

The inclusion of the growth adjustment in the calculation of the above-benchmark surplus and GSM is consistent with the approach adopted elsewhere. Victorian decisions have provided for the forecast operating expenditure against which efficiency rewards are calculated to be adjusted on an ex-post basis for differences between the forecast and actual scale cost drivers.[281]

14.3.3 Proposed efficiency and innovation benchmarks

The GSM applies to the efficiency gains in excess of the efficiency and innovation benchmarks. Our efficiency and innovation benchmarks for AA3 are based on forecast

[280] Western Power is required to pay an annual levy towards the operating costs of the safety regulator Energy*Safety*.
[281] p654, *Final Decision - Victorian electricity distribution network service providers Distribution determination 2011–2015*, AER, October 2010.

operating expenditure, adjusted for uncontrollable costs. This is consistent with the efficiency and innovation benchmark for the AA2 period.

Table 101 details the proposed efficiency and innovation benchmarks for AA3.

Table 101: Efficiency and innovation benchmarks

($ million real at 30 June 2012)	2012/13	2013/14	2014/15	2015/16	2016/17
Total forecast operating expenditure	496.4	509.9	540.6	562.5	604.2
Less forecast costs for defined benefit superannuation schemes	2.9	2.9	2.9	2.9	2.9
Less forecast non-revenue cap services cost	18.0	18.5	19.4	20.4	21.8
Less forecast licence fees	0.05	0.05	0.05	0.05	0.05
Less forecast energy safety levy	4.3	4.5	4.6	4.8	4.9
Efficiency and innovation benchmark (forecast)	**471.1**	**484.0**	**513.6**	**534.5**	**574.6**

14.3.4 Above-benchmark surplus

We will calculate the above-benchmark surplus (ABS) based on the difference between the efficiency and innovation benchmark (adjusted for growth) and actual operating expenditure adjusted to exclude the specified uncontrollable costs. The GSM reward is based on the ABS being carried forward for five years after the reduction in costs was achieved. In the event that there is no surplus, the ABS for that year will be zero. We have also adjusted the formula used to calculate the above benchmark surplus to cater for the five-year length of AA3 (compared to the three years of AA2).

Setting the SSBs at the minimum service level increases the incentives for achieving cost efficiencies by appropriately balancing the rewards that can be achieved under the GSM for efficiency gains against achieving minimum levels of service. As required by section 6.26 of the Access Code, we receive no rewards under the GSM for efficiency improvements to the extent we are unable to meet the SSBs.

As discussed in section 14.3.1, when determining the above benchmark surplus we will adjust the actual operating expenditure to exclude the following uncontrollable costs:

- operating expenditure incurred by Western Power in accordance with the D-factor
- operating costs associated with unforeseen events
- operating costs associated with changes to the Technical Rules
- superannuation costs for defined benefit schemes
- costs associated with non-revenue cap services
- licence fees and the Energy*Safety* levy

14.4 Investment adjustment mechanism

We propose that the current form of the investment adjustment mechanism (IAM) is retained for AA3, unchanged from AA1 and AA2.

The impact of this mechanism will be taken into account when establishing the target revenue for AA4.

The IAM will adjust target revenue in AA4 to leave Western Power and customers economically neutral as a result of any differences between the AA3 forecast and actual transmission and distribution capital expenditure in designated categories. The designated categories are growth-related investment, the State Underground Power Program (SUPP) and the Rural Power Improvement Program (RPIP)[282]. These categories have been selected due to the inherent variability in capital expenditure for these types of investment. It is reasonable that we and our customers are not penalised or rewarded for differences between the forecast and actual expenditure.

The IAM's design is important in relation to future application of the NFIT. When assessing compliance with the requirements of section 6.51A of the Access Code (including the new facilities investment test), a reasonable method would be to rely on the incentive properties inherent in the access arrangement.

For categories of capital expenditure not subject to the IAM there is a financial incentive to out-perform the forecast capital investment by delivering the capital program efficiently. Our proposal to use actual depreciation in setting the opening capital base at the beginning of AA4 further increases this financial incentive. This incentive helps ensure capital expenditure that is not subject to the IAM meets the requirements of section 6.51A of the Access Code.

The IAM also supports the forecasting method we have adopted for customer-driven capital investment. Customer-driven capital investment is based on a five-year historical average level of expenditure, escalated with the forecast movements in labour and material prices. The IAM adjusts for any differences between these forecasts and actuals.

The details of the operation of the IAM are provided in section 7.3 of the proposed access arrangement.

14.5 D-factor

We are proposing to retain the D-factor in its current format, with a minor adjustment that links the D-factor to a capital project list and the Transmission Network Development Plan. This change will ensure there is documented evidence of any planned or potential capital investment that may be deferred by demand management or alternative options to network augmentation.

The purpose of the D-factor scheme is to allow the recovery of efficient costs incurred when undertaking demand management initiatives.

The impact of this mechanism will be taken into account when establishing the target revenue for AA4.

Features of the D-factor are:

- it applies to both transmission and distribution expenditure
- it provides for the recovery in the next access arrangement period of:

[282] RPIP is currently inactive. There are no expenditure forecasts for RPIP over the AA3 period. RPIP remains part of the IAM to allow for the State Government to reactivate RPIP at anytime during the AA3 period.

- any additional operating expenditure we incur as a result of deferring or avoiding a capital expenditure project during the forthcoming access arrangement period
- any additional operating or capital expenditure we incur in the forthcoming access arrangement period in relation to demand management initiatives
- the recovery of costs are subject to a test for efficiency and prudence (where a business case can demonstrate that any operating expenditure meets section 6.40 and 6.41 of the Access Code and that any capital expenditure meets section 6.51A of the Access Code). Costs are only recoverable if there is an approved business case for the relevant expenditure and this business case is made available to the Authority

The D-factor offsets the bias towards capital expenditure solutions created by the investment adjustment mechanism (IAM).

The capital project list and the Transmission Network Development Plan include capital projects that are not certain enough to have been included in the AA3 expenditure forecasts at time of preparation. Linking the D-factor to these helps remove the bias towards capital investment solutions for any projects that are delivered during the period. It also provides visibility where additional operating expenditure we incur results from the efficient deferral of capital expenditure.

From a sustainability perspective, we and our customers value alternative options to network augmentation and demand management initiatives. Retaining the D-factor into AA3 enables the value placed on sustainability to be considered alongside traditional capital solutions.

The D-factor is consistent with the objectives of the price control and the Access Code objective. The detail of the D-factor scheme is provided in section 7.6 of the proposed access arrangement.

14.6 Unforeseen events

The unforeseen event mechanism ensures that an event beyond our control does not result in the business incurring unrecovered costs. For AA3, the access arrangement will include the following list of events that are beyond our control**:**

- the introduction of full retail contestability
- the mandated roll out of advanced interval metering
- the introduction of any carbon pricing scheme or mechanism

For AA3, we propose to continue to rely on access arrangement and Access Code provisions relating to unforeseen events to recover the costs arising from a force majeure event. We consider that they provide strong incentives to efficiently manage the business’ response to a force majeure event. Where it is possible to do so, we will purchase insurance of the standard of a reasonable and prudent person in relation to force majeure events. Where it is appropriate to do so, we will utilise the provisions for recovery of unforeseen costs in accordance with the access arrangement.

The proposed unforeseen event provisions are substantially unchanged from AA2, We propose that section 7.1 of the access arrangement be modified to the following:

> *A force majeure event includes but is not limited to any costs arising from the introduction of any scheme or mechanism with respect, directly or indirectly, to emissions of greenhouse gases and with respect to any activity including pricing, reduction, cessation, offset and sequestration (including the Carbon Pricing Mechanism*

announced by the Commonwealth in February 2011), full retail contestability, and the mandated roll-out of Advanced Interval Meters to the extent that such costs were not included in the calculation of target revenue for this access arrangement period or otherwise addressed through the trigger event provisions in section 8 of this access arrangement.

The proposed revision makes it clear that the introduction of any mechanism or scheme introduced to address the emission of greenhouse gases; full retail contestability; or the mandated roll-out of advanced interval meters could be matters that lead to unexpected, significant cost increases during AA3.

14.7 Technical Rules changes

We are not proposing any change to the Technical Rules change provision for AA3.

Our forecast capital and operating expenditure for AA3 reflects the costs associated with meeting the requirements for asset and system performance under the Technical Rules that are expected to be in effect at the time of the Authority's approval of the access arrangement.

As stipulated in section 4.6.2 of the AAI Guidelines, if the Technical Rules are amended over the course of AA3, then we will provide a report to the Authority setting out:

- a description of the nature and timing of the impact of the change to the Technical Rules on our operating and capital costs
- a fair and reasonable estimate of the additional costs (or cost savings) we will accrue to as a result of the change to the Technical Rules

The Authority will then determine an adjustment to target revenue for AA4 to compensate for any change in costs during AA3, in accordance with the provisions contained in sections 6.9 to 6.12 of the Access Code.

14.8 Trigger events

The Access Code provides the grounds for re-opening the entire access arrangement for review in the presence of trigger events. For AA3 we list the following as trigger events:

- the introduction of full retail contestability
- the mandated roll out of advanced interval metering
- the introduction of any carbon pricing scheme or mechanism

These events would significantly impact future expenditure and would require material revisions to the access arrangement should they occur.

In AA3 we propose revisions to the trigger events, which recognise the potentially significant impacts of certain events on future expenditure. Due to the uncertainty around the Commonwealth Government's mechanism to address emissions of greenhouse gases, we are proposing a modification of the term 'emissions trading scheme' to 'any carbon pricing scheme or mechanism'.

We propose that section 8 of the access arrangement, for the trigger events, by modified to the following:

A trigger event may include without limitation the introduction of any scheme or mechanism with respect, directly or indirectly, to emissions of greenhouse gases and with respect to any activity including pricing, reduction, cessation, offset and sequestration (including the Carbon Pricing Mechanism announced by the

> *Commonwealth in February 2011), full retail contestability, and the mandated roll-out of Advanced Interval Meters to the extent that such costs were not included in the calculation of target revenue for this access arrangement period or otherwise addressed through the unforeseen event provisions in sections 7.1.1 to 7.1.4 of this access arrangement.*

We also propose that the designated date by which proposed revisions must be submitted to the Authority be revised to 90 business days after a trigger event has occurred. Ninety business days is a more appropriate timeframe considering the resources needed to compile proposed revisions.

14.9 AAI Guidelines provisions

The requirements regarding the GSM are detailed in section 7 of the AAI Guidelines.

Table 102 details the requirements with a cross reference to the relevant section of this AAI.

Table 102: AAI Guidelines compliance for the gain sharing mechanism

AAI Guidelines section #	AAI Guidelines wording	Cross reference
7.1	*Under section 5.25 of the Access Code an access arrangement which contains a gain sharing mechanism must, and an access arrangement which does not contain a gain sharing mechanism may, contain efficiency and innovation benchmarks.*	Section 14.3.3
7.1	*Efficiency and innovation benchmarks must, under section 5.26 of the Access Code:* • *be sufficiently detailed and complete to permit the Authority to make a determination at the next access arrangement review;* • *provide an objective standard for assessing the service provider's efficiency and innovation during the access arrangement period; and* • *be reasonable.*	Section 14.3.3
7.2	*Information supporting a gain sharing mechanism is required to assist in the assessment of whether the gain sharing mechanism meets the requirements of the Access Code.*	Section 14.3
7.3	*Demonstrating the effects of a gain sharing mechanism in the previous access arrangement period requires an explanation of the increments for efficiency gains and/or decrements for efficiency losses that have occurred and the quantification of any carry-over amount. Evidence must be provided to support any financial information included in the calculations.*	Section 12.2.1
7.3	*In circumstances where an existing gain sharing mechanism is proposed to continue from one access arrangement period to the next, the access arrangement information must demonstrate how the pre-existing gain sharing mechanism meets the objectives of section 6.21 of the Access Code.*	Section 14.3

15 Pricing methods

This chapter provides a description of Western Power's pricing methods to address the explanatory information required by chapter 7 of the Access Code.

Further detail on reference tariffs are set out in the price list provided at Appendix F.1 of the proposed access arrangement. Appendix F.2 of the proposed access arrangement provides price list information which explains the pricing methods used to develop tariff prices for AA3 in more detail.

This chapter:

- lists our reference tariffs for AA3
- explains the Access Code pricing method objectives
- describes how we comply with the Access Code pricing method objectives relating to the recovery of forward-looking efficient costs, the structure, cost reflectivity and predictability of tariff charges and the management of price shocks
- provides information on our policies relating to prudent discounting and discounts for distributed generation
- explains our use of side-constraints in AA3 to limit annual price changes to individual reference tariffs

15.1 Key messages

- The proposed revisions to the pricing methods comply with Chapter 7 of the Access Code.
- The pricing methods remain unchanged from AA2.
- There are 17 reference tariffs in AA3, including four new reference tariffs relating to bi-directional reference services.
- Revisions also include two improvements to the streetlight tariff (RT9).
- The prudent discounting policy remains unchanged from AA2.
- The policy on discounts for distributed generation remains unchanged from AA2.

15.2 Reference tariffs provided in AA3

We will include 17 reference tariffs in our access arrangement for AA3. Of these, 12 remain unchanged from AA2 and one has changed slightly. We are also introducing four new bi-directional tariffs (RT13 to RT16) to replace the single bi-directional tariff that was offered in AA2 (RT12).

The new tariffs address the growing take-up of bi-directional tariffs by providing both 'anytime energy' and 'time of use' tariffs for residential and non-residential users. The reference tariffs were introduced as a result of a recent review that we undertook of our bi-directional services and tariffs.

There will be two improvements to the streetlight tariff (RT9). The first improvement updates the list of streetlight asset types on our network. Previously, the list of streetlight assets did not include all asset types.

The second improvement separates the list of streetlight asset types into 'current' and 'obsolete' asset types. 'Current' assets are those that are still offered for installation, while 'obsolete' assets are the asset types on the network that are no longer offered. The changes to RT9 improve the information and clarity of the streetlight asset types that exist on our network, as well as identifying those that are available for installation.

The price list information at Appendix F.2 of the proposed access arrangement contains further detail on the changes to RT9 as well as all other reference tariffs.

Table 103 lists the reference tariffs for AA3.

Table 103: Reference tariffs

Reference tariff	Reference tariff description	Type of reference tariff	Revenue cap recovery	Retained from AA2 or new or changed in AA3
RT1	Anytime energy (residential) tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA2
RT2	Anytime energy (business) tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA2
RT3	Time of use energy (residential) tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA2
RT4	Time of use energy (business) tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA2
RT5	High voltage metered demand tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA2
RT6	Low voltage metered demand tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA2
RT7	High voltage contract maximum demand tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA2
RT8	Low voltage contract maximum demand tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA2
RT9	Streetlight tariff	Reference tariff for streetlights	Tx and Dx (includes streetlight operating & maintenance costs)	Changed for AA2
RT10	Unmetered supplies tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA2
RT11	Distribution connected generation tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA2
RT13	Anytime energy (residential) bi-directional tariff	Reference tariff for Dx users	Tx and Dx	New for AA3
RT14	Anytime energy (business) bi-directional tariff	Reference tariff for Dx users	Tx and Dx	New for AA3
RT15	Time of use (residential) bi-directional tariff	Reference tariff for Dx users	Tx and Dx	New for AA3
RT16	Time of use (business) bi-directional tariff	Reference tariff for Dx users	Tx and Dx	New for AA3
TRT1	Transmission nodal tariff (loads)	Reference tariff for Tx users	Tx	Retained from AA2

Reference tariff	Reference tariff description	Type of reference tariff	Revenue cap recovery	Retained from AA2 or new or changed in AA3
TRT2	Transmission nodal tariff (generators)	Reference tariff for Tx users	Tx	Retained from AA2

15.3 How the pricing methods comply with the Access Code objectives

Chapter 7 of the Access Code defines the pricing methods and objectives for the access arrangement.

This section demonstrates that the pricing methods that we have used for AA3 comply with each relevant section of chapter 7.

Recovery of forward-looking efficient costs

In accordance with section 7.3(a) of the Access Code, our target revenue recovers the forward-looking efficient costs of providing revenue cap access services[283].

> **Access Code provisions**
>
> **Section 7.3**
>
> *Subject to sections 7.5, 7.7 and 7.12 the pricing methods in an access arrangement must have the objectives that:*
>
> *a) reference tariffs recover the forward-looking efficient costs of providing reference services;*

Reference tariffs for AA3 recover the forward-looking efficient costs associated with reference services, while non-reference tariffs recover the efficient costs of non-reference services. The efficient costs that we incur in the provision of non-revenue cap services[284] are recovered on a fee-for-service basis.

Reference tariffs for the users of the distribution network include costs relating to both distribution and transmission services. Transmission reference tariffs only include costs relating to transmission services.

We also charge capital contributions to customers to recover the costs associated with connecting them to our network when these costs cannot be recovered through reference tariff revenue. Our contributions policy details how we charge customers to recover the costs of connection that do not meet the NFIT at section 6.52 of the Access Code.

[283] As discussed in section 9.2 of this document, revenue cap services covers all services that we provide to transmit and distribute electricity, including reference and non-reference services. It also incorporates the associated metering services required under the Metering Code, such as a scheduled meter reading.

[284] Non-revenue cap services are non-network or ancillary services that we provide, such as high load escorts.

Reference tariffs are priced between incremental and stand-alone costs

In accordance with section 7.3(b) of the Access Code, reference tariffs are priced so that a user is charged an amount that is:

- greater than or equal to the incremental cost of providing that reference service
- less than or equal to the stand alone cost of providing that reference service

The price list information at Appendix F.2 of the proposed access arrangement explains how our reference tariffs are calculated so that they are priced between our incremental and stand alone costs of providing reference services.

> **Access Code provisions**
>
> **Section 7.3**
>
> *Subject to sections 7.5, 7.7 and 7.12 the pricing methods in an access arrangement must have the objectives that:*
>
> *b) the reference tariff applying to a user:*
>
> *i. at the lower bound, is equal to, or exceeds, the incremental cost of service provision; and*
>
> *ii. at the upper bound, is equal to, or is less than, the stand-alone cost of service provision.*

This process involves identifying the costs to provide a reference service that are fixed and those that are variable. This enables us to derive the incremental and stand alone costs of providing the reference service. We then set our reference tariffs to recover these costs, so that the price we charge for a reference service sits between the incremental and stand alone costs of provision.

Charges reflect the average cost of service provision

In accordance with section 7.4(a) of the Access Code, charges may vary according to the customer's location, but only to the extent that it reflects the differences in the average cost of providing that service in different parts of the network.

> **Access Code provisions**
>
> **Section 7.4**
>
> *Subject to sections 7.5, 7.7 and 7.12 the pricing methods in an access arrangement must have the objectives that:*
>
> *a) the charges paid by different users of a reference service differ only to the extent necessary to reflect differences in the average cost of service provision to the users;*

We set 'locational' prices for customers with an annual maximum demand of greater than 1 MVA. To do this we have established locational zones which group areas of similar supply cost (CBD, urban, rural, mixed and mining) and the price of reference tariffs charged reflect the average costs to supply these areas and the customers' use of the network.

Locational pricing does not exist for customers with an annual maximum demand of less than 1 MVA. The costs created by these customers are allocated according to usage, so the average costs of the network are shared between customers depending on their relative use of the network.

Tariffs accommodate reasonable requirements of users collectively

In accordance with section 7.4(b) of the Access Code, the structures of the majority of reference tariffs in the current access arrangement (for the AA2 period) were developed through a consultative process prior to the commencement of the access arrangement. The structure of all but one of the reference tariffs from AA2 is being retained for AA3.

The only change proposed for AA3 is the replacement of the bi-directional reference tariff

> **Access Code provisions**
>
> **Section 7.4**
>
> *Subject to sections 7.5, 7.7 and 7.12 the pricing methods in an access arrangement must have the objectives that:*
>
> b) *the structure of reference tariffs so far as is consistent with the Code objective accommodates the reasonable requirements of users collectively;*

RT12 with four new bi-directional reference tariffs RT13 to RT16. Development of these new reference tariffs included comprehensive consultation with major stakeholders including the Office of Energy, Synergy and other retailers.

During the consultation process with stakeholders in preparation for AA3, we confirmed acceptance of the current tariff approach, which will continue in AA3.

Tariff structures enable users to predict likely changes

In accordance with section 7.4(c) of the Access Code, the structure of reference tariffs enables users to predict the likely annual changes in reference tariffs during the access arrangement period.

> **Access Code provisions**
>
> **Section 7.4**
>
> *Subject to sections 7.5, 7.7 and 7.12 the pricing methods in an access arrangement must have the objectives that:*
>
> *c) the structure of reference tariffs enables a user to predict the likely annual changes in reference tariffs during the access arrangement period;*

Our reference tariffs are specified clearly for the first year of the access arrangement period. For subsequent years, average tariff movements are smoothed over the period. Users can predict likely annual tariff changes with the assistance of the average price paths for transmission and distribution reference tariffs that are provided in Table 97 in section 13.3 of this document. The average price paths in detail the average price movements for transmission and distribution reference tariffs to enable users to understand and predict the likely annual changes in reference tariffs during the access arrangement period.

Our use of side constraints provides further assistance to users to predict the likely annual change in reference tariffs during AA3 (discussed in section 15.5). Side constraints limit annual price movements for individual reference tariffs. This enhances users' ability to predict likely tariff change during AA3 because the maximum value of annual tariff movements are known through the limitations provided by the side constraint imposed.

Management of price shocks – compliance with section 7.4 (d)

In accordance with section 7.4(d) of the Access Code, price shocks during the period are managed by:

> **Access Code provisions**
>
> **Section 7.4**
>
> *Subject to sections 7.5, 7.7 and 7.12 the pricing methods in an access arrangement must have the objectives that:*
>
> *d) the structure of reference tariffs avoids price shocks (that is, sudden material tariff adjustments between succeeding years).*

- smoothing the recovery of forecast reference service revenue to moderate tariff price movements across and between access arrangement periods
- incorporating side constraints to limit annual price movements for each reference tariff (discussed further at section 15.5)

Tariffs components reflect the underlying cost structure

Reference tariffs have been designed to recover the cost of service provision in a cost-reflective manner.

In accordance with section 7.6 of the Access Code, variable tariff components reflect the incremental costs of service provision and the costs in excess of incremental cost are recovered through tariff components that do not vary with usage.

To do this, we align the fixed and variable components of the costs to provide a reference service with the fixed and variable components of the applicable reference tariffs. We do this by:

- defining the reference service provided
- allocating the fixed and variable network costs that we incur in the provision of the reference service
- setting the price of a reference tariff to recover the fixed and variable costs allocated to a reference service

The price list information at Appendix F.2 of the proposed access arrangement explains in detail the process that we use to set transmission and distribution reference tariffs.

> **Access Code provisions**
>
> **Section 7.6**
>
> Unless an access arrangement containing alternative pricing methods would better achieve the Code objective, for a reference service:
>
> a) the incremental cost of service provision should be recovered by tariff components that vary with usage or demand; and
>
> b) any amount in excess of the incremental cost of service provision should be recovered by tariff components that do not vary with usage or demand.

Postage stamp prices in certain cases

In accordance with section 7.7 of the Access Code, customers on the same reference tariff with an annual maximum demand of less than 1 MVA are charged an identical rate, regardless of their geographical location.

Our reference tariffs that offer postage stamp prices for customers with an annual maximum demand of less than 1 MVA are RT1 to RT6, RT9, RT10 and RT13 to RT16.

> **Access Code provisions**
>
> **Section 7.7**
>
> *The tariff applying to a standard tariff user in respect of a standard tariff exit point must not differ from the tariff applying to any other standard tariff user in respect of a standard tariff exit point as a result of differences in the geographic locations of the standard tariff exit points.*

15.4 Policies relating to discounting

This section sets out our policies in relation to prudent discounting and discounts for distributed generation.

15.4.1 Prudent discounting

We do not propose any changes to our prudent discounting policy for AA3. Our prudent discounting policy is provided at section 6.6 of the proposed access arrangement.

Our policy is that a prudent discount may be offered to a user or applicant seeking access to the Western Power Network where they can demonstrate that an alternative option will provide a comparable service at a lower price than that offered by reference services and reference tariffs.

> **Access Code provisions**
>
> **Section 7.9**
>
> *A service provider may propose in its access arrangement to discriminate between users in its pricing of services to the extent that it is necessary to do so to aid economic efficiency, including:*
>
> *a) by entering into an agreement with a user to apply a discount to the equivalent tariff to be paid by the user for a covered service; and*
>
> *b) then, recovering the amount of the discount from other users of reference services through reference tariffs*

Where a user can demonstrate with sufficient detail[285] that an alternative option will provide a comparable service at a lower price, we will offer a discounted price that is equal to the higher of the:

- cost of the alternative option
- incremental cost of service provision

The prudent discounting policy requires that we have regard to the pricing method objectives contained within the Access Code at sections 7.3 and 7.4. This is reflected through the requirement for the discounted price to equal the higher of the cost of the alternative option and the incremental cost of service provision. This restriction means that the discounted price will not fall below the incremental cost of service provision and in doing so not impose an additional cost on the other users of the covered network.

15.4.2 Discounts for distributed generation

We propose no changes to our policy on discounts for distributed generation in AA3. Our policy on discounts for distributed generation is contained in section 6.7 of the proposed access arrangement.

Our policy is that discounted tariffs can be provided where network costs are reduced as a result of an embedded generator connecting to the network. We believe it is appropriate to encourage distributed generation where this leads to a net saving in providing network services to customers.

The discount given to distributed generation is based on our avoided costs from a net present value (NPV) calculation[286] of the total costs incurred if the generator does not connect, less the total costs incurred if the generator connects. Our policy states that the NPV calculation of total costs should assess the operating and capital expenditure requirements under the *'with'* and *'without'* generator connection scenarios over a period of at least 10 years.[287]

Our policy on discounts for distributed generation states that the NPV of the avoided cost is converted to an equivalent annualised discount for a defined period of time. A discount will only be payable if the avoided cost calculated from the connecting generator is greater than zero. Our policy on discounts for distributed generation does not prevent the discount exceeding 100% of the user's tariff.

15.5 Side-constraint to limit annual tariff changes

We have included a side-constraint to limit annual changes to individual reference tariffs during the AA3 period. The purpose of the side-constraint is to mitigate the effects of price shock on individual customers during AA3, as required by section 7.4 (d) of the Access Code. The side-constraint does not apply in the first pricing year of AA3.

Side-constraints restrict annual movements in the recovery of revenue for each reference tariff. Where a large customer or a large number of customers switch between reference tariffs, the customers will be considered to have been on their new reference tariff when calculating the side-constraint values to not adversely affect our side-constraint calculations.

Our use of side-constraints in AA3 includes an adjustment to explicitly account for the recovery of tariff equalisation contributions (TEC) payable to the State Government. A

[285] The user or applicant must provide Western Power with sufficient details of the cost of the alternative option to enable the calculation of the annualised cost.
[286] At our regulated real pre-tax WACC.
[287] The NPV calculation would ideally extend to 20 years, however data limitations may dictate that a shorter period is more appropriate. A period of no less than 10 years is required by the policy.

separation of the TEC adjustment is required because the amount that we are obliged to recover through TEC is gazetted by State Government from time to time. It is appropriate that our ability to match the revenue amount recovered from reference tariffs with the amount payable through TEC be unconstrained by the side-constraint.

16 Policies and contracts

This chapter provides details on the policies and the contract that form part of our access arrangement for AA3. The policies and contract within our access arrangement govern how we contract with and provide access and network services to users of our network.

Section 5.1 of the Access Code sets out the policies and contract that must be included in our access arrangement. They include a:

- standard access contract – section 5.1(b)
- applications and queuing policy – section 5.1(g)
- contributions policy – section 5.1(h)
- transfer and relocation policy – section 5.1(i)

In addition to the policies and contract required by the Access Code, our access arrangement for AA3 also includes a:

- distribution headworks methodology
- low voltage charging scheme methodology

Both the distribution headworks methodology and the low voltage charging scheme methodology are not required by the Access Code but are referenced as attachments to the contributions policy which exists within our access arrangement.

16.1 Key messages

- The proposed revisions to our policies and contract comply with the requirements of Chapter 5 of the Access Code.
- Our standard access contract includes minor clause changes to improve its definitions, remove ambiguities and clarify the operation and processes around the provision of financial security provided by customers.
- We are proposing substantial improvements to our applications and queuing policy which will:
    - address the concerns and issues raised by the Authority, AEMC and our customers
    - make the process more customer-driven
    - provide quicker access for applicants that are not subject to network constraints
    - provide a formal enquiry stage to facilitate an exchange of information and allow applicants to better indicate their requirements
    - create ‘competing application groups’ to group applicants behind common network constraints and reduce the need for queuing
    - achieve greater economic efficiency by developing solutions that address common network constraints and satisfy the demand of a number of applicants
- We have made minor revisions to our contributions policy to remove ambiguities and, in relation to the two methodologies that attach to the policy:
    - our distribution headworks methodology includes minor revisions to remove an outdated appendix and improve the process to update the price list

- we will retain the low voltage charging scheme methodology, which will be the subject of a proposed in-period submission seeking mid-term revisions as part of AA2 – for the purposes of this submission we assume that the methodology will be approved by the Authority and forms part of our access arrangement in AA2.
- We retain our current transfer and relocations policy and make no changes for AA3.

16.2 Standard access contract (electricity transfer access contract)

The electricity transfer access contract (ETAC) is our standard access contract. The ETAC provides the standard terms and conditions that we use to contract with customers for the provision of services on our covered network. It provides our terms and conditions in relation to the services we offer, the tariffs we charge, invoicing and payment terms, a customer's provision of financial security, technical compliance provisions and liability and indemnity, among other things.

We will make a number of changes to the ETAC to:

- remove the 'modified service' provision at clause 3.1(d) to clarify that the ETAC provides the terms and conditions for access to our reference services and that a modified service is not a reference service
- remove the reference to 'de-energisation' in clause 3.6 to ensure a connection is not unintentionally deleted
- amend the definition of 'payment error' and add two new clauses 8.6(f) and 8.6(g) to correctly provide for changes made to clause 8.6 of the ETAC in AA2
- amend clause 9 (Security for Charges) to remove ambiguity, improve clarity and provide reasonable financial protection for Western Power.

This section summarises the proposed revisions to the ETAC for the AA3 period.

Access Code provisions

Section 5.3

A standard access contract must be:

- a) *reasonable; and*
- b) *sufficiently detailed and complete to:*
  - i. *form the basis of a commercially workable access contract; and*
  - ii. *enable a user or applicant to determine the value represented by the reference service at the reference tariff.*

Section 5.4

A standard access contract may:

- a) *be based in whole or in part upon the model standard access contract, in which case, to the extent that it is based on the model standard access contract, any matter which in the model standard access contract is left to be completed in the access arrangement, must be completed in a manner consistent with:*
  - i. *any instructions in relation to the matter contained in the model standard access contract; and*
  - ii. *section 5.3;and*
  - iii. *the Code objective; and*
- b) *be formulated without any reference to the model standard access contract and is not required to reproduce, in whole or in part, the model standard access contract.*

16.2.1 Modified Service – clause 3.1(d)

The ETAC is the standard access contract we use to provide access to our reference services and therefore should not be used for the provision of a modified service (that is not a reference service).

Clause 3.1(d) has been used in the past as a temporary measure where a short term issue or constraint existed that required resolution before a reference service could be provided. We will remove clause 3.1(d) and instead provide a non-reference service as the temporary measure in these circumstances until it is possible to provide a reference service.

It is important that we clearly distinguish between the terms and conditions of reference services from non-reference services. This will ensure that our customers understand the service they will receive and the prices to be paid, so that we can effectively manage our obligations and commitments.

16.2.2 De-energisation – clause 3.6

We have removed reference to 'de-energisation' from clause 3.6. Clause 3.6 deals with the deletion of connection points.

The de-energisation of a connection point is a temporary action. It is typically sought by users seeking a temporary interruption of service with a subsequent re-energisation (for example, when a retailer requests a temporary disconnection for non-payment). A request to de-energise is actioned at the meter level to temporarily stop energy flow, however it does not remove the connection point permanently.[288]

Removing the reference to de-energisation from clause 3.6 ensures that a connection point is not unintentionally deleted from an ETAC when the intent was to simply de-energise.

Clause 3.6, as presently drafted, inadvertently conflicts with current practice relating to de-energising connection points. Under the current practice a connection point is not, as contemplated by clause 3.6(c)(iii), deleted from an ETAC when it is de-energised. A connection point is deleted from an ETAC only when it is transferred to another access contract or physically disconnected from the network.

This amendment provides clarity to users and to the business and avoids the consequences of a deletion when a simple de-energisation was sought.[289]

16.2.3 Clause 8.6 and the definition of payment error

We are amending the definition of 'payment error' at clause 8.6 of the ETAC. Clause 8.6 makes reference to payment errors which arise as a result of an error in the data used to calculate a tax invoice. However, the definition of 'payment error' was not updated to reflect this.

The variation to clause 8.6 was introduced for AA2. The explanation provided for the variation was:

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[288] A request to delete a connection point from an ETAC is permanent. It occurs when either a connection point is transferred from one access contract to another access contract (under a customer transfer code request) or when it is permanently disconnected and physically removed from the network. A request to delete a connection point is actioned by permanently removing the connection point from the ETAC. However, the de-energisation of a connection point and re-energisation of a de-energised connection point are administrative functions under the terms of the ETAC, because the connection point still remains within the ETAC.

[289] The deletion of a connection point would require a user to apply through the processes of the applications and queuing policy to re-activate the deleted connection point.

> *…under or over payments arising from a payment error will give rise to a payment adjustment if notice of the error is given by the affected party within 18 months unless the payment error resulted from a data error. If the payment error resulted from an error in the data used to calculate the charges and the error occurred in one or more accounting periods, an entitlement to an adjusting payment applies only to the errors in the accounting periods within the preceding 12 months before the error was notified. The 12 month limitation for data errors aligns with a similar limitation under section 65 of the Energy Operators (Powers) Act 1979 for errors in meter data and promotes accuracy in the data information kept by both parties.*
>
> *This promotes the interests of the parties for certainty in the charges that are payable; which creates a commercially workable access contract.*
>
> *The charge error provisions of the ETAC do not affect the operation of sections 65 and 66 of the Energy Operators (Powers) Act.*[290]

The definition of 'payment error' requires amendment to cover all of the situations covered by clause 8.6. The present definition is limited only to payment errors where the invoiced amount was correct but not paid in full or overpaid. It does not cover the situation where the tax invoice itself contained the wrong amount because it was calculated using incorrect data. To address this inconsistency the definition of 'payment error' has been amended to the following:

> *a) any underpayment or overpayment by a Party* of any amount in respect of a Tax Invoice*; or*
>
> *b) any error in a Tax Invoice* (including the omission of amounts from that Tax Invoice*, the inclusion of incorrect amounts in that Tax Invoice*, calculation errors in the preparation of a Tax invoice* or a Tax Invoice* being prepared on the basis of data which is later established to have been inaccurate).*

As a result of the amendments made in AA2 to clause 8.6, we will introduce new clauses 8.6(f) and 8.6(g) in addition to amending the definition of 'payment error'. The new clauses clarify the time that a payment error is taken to be made in the situation where the error arises from an invoice being more or less than what it should have been. They state:

8.6(f) Where a Payment Error is an error as a result of which the amount set out in a Tax Invoice* is less than what it would have been had the error not been made, the Payment Error* will be taken to have occurred on the Due Date* of the Tax Invoice*.*

8.6(g) Where a Payment Error is an error as a result of which the amount set out in a Tax Invoice* is more than what it would have been had the error not been made, the Payment Error* will be taken to have occurred on the date the User* has paid the total amount of the Tax Invoice* in full.*

These clauses are required to allow clause 8.6 to operate correctly. Their addition is appropriate because they establish the date that a payment error is said to have occurred, so that the provisions of clause 8.6 that reference the payment error date (where the error arises from an invoice being more or less than what it should have been) can function properly.

[290] *Appendix 12 – Standard Access Contract: Demonstration of Code Compliance, AA2 Access Arrangement Information, Western Power*, October 2008.

16.2.4 Clause 9 (Security for charges)

Amendments are required to clause 9 of the ETAC (Security for Charges) to remove ambiguity, improve clarity and provide reasonable financial protection to Western Power.

Uncertainty relating to the timeframe to propose a 'nominated person' and provide security

Clause 9 does not presently stipulate the timeframe within which a user must propose a 'nominated person' or provide security following a request from Western Power for security. This creates uncertainty for Western Power and users and has the potential to lead to disagreement between the parties.

Clause 9 will be amended to require a user to propose a 'nominated person' within 15 business days of Western Power's request for security and then provide security within 15 business days thereafter.

Financial security no longer adequate

We have amended the ETAC through the introduction of new clause 9(c). Under clauses 9(a)(ii)(A) and 9(a)(ii)(B) the security provided by a user must be equal to the charges for two months services. The new clause 9(c) requires users, on request, to provide updated security when the previous security provided is no longer equal to the charges for two months services.

The new clause 9(c) is required because the previous security we held can become insufficient (for the purposes of clause 9(a)(ii)(A) or 9(a)(ii)(B)) and no longer provide the required level of financial protection when the charges under an ETAC increase. The charges under an ETAC can increase:

- because a retailer takes on additional customers during the term of its ETAC, increasing the total services provided and the charges payable for those services
- as a result of approved increases in reference tariffs – this can arise several times under an ETAC of long duration (for instance, during a 30 year contract)

The current ETAC does not expressly require users to provide updated security to ensure that it is equal to the existing charges for two months services. While this is arguably implied in clause 9(a)(ii), the ambiguity surrounding the matter may lead to disagreement between parties. The new clause 9(c) provides clarity on this matter. This amendment is reasonable and simply reflects the present intention of clauses 9(a)(ii)(A) and 9(a)(ii)(B).

Requirement to provide replacement security

We have included a new clause 9(d), which requires replacement security to be provided if the security held by Western Power under clause 9(a)(ii)(A) or 9(a)(ii)(B) is called on or if that security ceases to be enforceable for any reason (including as a result of the expiry of the security).

The intention of clause 9 is to provide a reasonable level of financial protection for Western Power. If we were to call on the security we hold or if the security becomes unenforceable and the security is not replaced or reinstated to the level stipulated under clause 9(a)(ii), then the intended financial protection is diminished.

This amendment is required so that our financial protection can be maintained as intended throughout the duration of the ETAC.

Financial security provided through parent company guarantee no longer adequate

A new clause 9(e) has been added to the ETAC. Clause 9(e) requires a user to provide alternative security under clause 9(a)(ii)(A) or 9(a)(ii)(B) when it has provided a parent company guarantee but its parent company ceases to have the resources to meet the user's obligations under the ETAC.

Under clause 9(a)(ii)(C), a user may provide a parent company guarantee if Western Power is satisfied that the parent company's financial and technical resources are able to meet the user's obligations under the ETAC. This determination is made by Western Power at the time the user elects to provide a parent company guarantee.

The current ETAC does not consider the situation where a parent company's circumstances change and it no longer has the resources to meet the criteria under clause 9(a)(ii)(C). A decline in the credit position of the parent company providing a guarantee is an example of where this may occur.

The intention of clause 9 is to provide a reasonable level of financial protection for Western Power. This level of protection is lost when a parent company can no longer reasonably meet the criteria under clause 9(a)(ii)(C). This amendment is reasonable and supports the previously approved provisions of the standard ETAC.

16.2.4.1 Access Code compliance

Section 5.3 of the Access Code provides guidance on the content and requirements of a standard access contract. In compliance with section 5.3 of the Access Code, our ETAC revisions for AA3 are:

- reasonable
- enable a user or applicant to determine the value represented by a reference service at the reference tariff
- sufficiently detailed to form the basis of a commercially workable access contract

The form and content of the ETAC for AA3 remains largely unchanged from the ETAC approved by the Authority in AA2. The minor revisions proposed for AA3 improve the definitions contained within the ETAC, remove ambiguities and clarify the operation and processes around the provision of financial security to be provided by customers. Our revisions further the objectives of section 5.3 of the Access Code and maintain Access Code compliance.

16.3 Applications and queuing policy

Our applications and queuing policy details the processes, procedures and requirements for customers seeking to apply for and obtain access to our network. The purpose of an applications and queuing policy is to manage applications for an access contract in an orderly and fair manner, especially where network capacity is scarce.

Access Code provisions

Section 5.7

An applications and queuing policy must:

- *a) to the extent reasonably practicable, accommodate the interests of the service provider and of users and applicants; and*
- *b) be sufficiently detailed to enable users and applicants to understand in advance how the applications and queuing policy will operate; and*
- *c) set out a reasonable timeline for the commencement, progressing and finalisation of access contract negotiations between the service provider and an applicant, and oblige the service provider and applicants to use reasonable endeavours to adhere to the timeline; and*
- *d) oblige the service provider, subject to any reasonable confidentiality requirements in respect of competing applications, to provide to an applicant all commercial and technical information reasonably requested by the applicant to enable the applicant to apply for, and engage in effective negotiation with the service provider regarding, the terms for an access contract for a covered service including:*
  - *i. information in respect of the availability of covered services on the covered network; and*
  - *ii. if there is any required work:*
    - *A. operational and technical details of the required work; and*
    - *B. commercial information regarding the likely cost of the required work; and*
- *e) set out the procedure for determining the priority that an applicant has, as against another applicant, to obtain access to covered services, where the applicants' access applications are competing applications; and*
- *f) to the extent that contestable consumers are connected at exit points on the covered network, contain provisions dealing with the transfer of capacity associated with a contestable consumer from the user currently supplying the contestable consumer ("outgoing user") to another user or an applicant ("incoming user") which, to the extent that it is applicable, are consistent with and facilitate the operation of any customer transfer code; and*
- *g) establish arrangements to enable a user who is:*
  - *i. a 'supplier of last resort' as defined in section 67 of the Act to comply with its obligations under Part 5 of the Act; and*
  - *ii. a 'default supplier' under regulations made in respect of section 59 of the Act to comply with its obligations under section 59 of the Act and the regulations; and*
- *h) facilitate the operation of Part 9 of the Act, any enactment under Part 9 of the Act and the 'market rules' as defined in section 121(1) of the Act; and*
- *i) if applicable, contain provisions setting out how access applications (or other requests for access to the covered network) lodged before the start of the relevant access arrangement period are to be dealt with.*

Section 5.8

The paragraphs of section 5.7 do not limit each other.

Access Code provisions

Section 5.9

Under section 5.7(e), the applications and queuing policy may:

a) *provide that if there are competing applications, then priority between the access applications is to be determined by reference to the time at which the access applications were lodged with the service provider, but if so the applications and queuing policy must:*

   i. *provide for departures from that principle where necessary to achieve the Code objective; and*

   ii. *contain provisions entitling an applicant, subject to compliance with any reasonable conditions, to:*

      A. current information regarding its position in the queue; and

      B. information in reasonable detail regarding the aggregated capacity requirements sought in competing applications ahead of its access application in the queue; and

      C. information in reasonable detail regarding the likely time at which the access application will be satisfied; and

b) *oblige the service provider, if it is of the opinion that an access application relates to a particular project or development:*

   i. *which is the subject of an invitation to tender; and*

   ii. *in respect of which other access applications have been lodged with the service provider, ("project applications") to, treat the project applications, for the purposes of determining their priority, as if each of them had been lodged on the date that the service provider becomes aware that the invitation to tender was announced.*

Section 5.9A

If:

a) *an access application (the "first application") seeks modifications to a contract for services; and*

b) *the modifications, if implemented, would not materially impede the service provider's ability to provide a covered service sought in one or more other access applications (each an "other application") compared with what the position would be if the modifications were not implemented, then the first application is not, by reason only of seeking the modifications, a competing application with the other applications.*

Our applications and queuing policy revisions for AA3 build on the mid-term revisions that were proposed during the AA2 period. Our mid-term revisions sought changes to improve the operation of the applications and queuing policy, however the Authority chose not to approve our mid-term revisions at AA2, stating:

> *The Authority's final decision is to not approve Western Power's proposal, as the Authority is not persuaded, at this time, that the advantages of doing so, in light of the serious concerns regarding the revisions raised by interested parties, outweigh the disadvantages of varying the access arrangement prior to the next access arrangement review. The Authority considers that the concerns raised by interested parties should be addressed by Western Power and taken into account when it submits its proposed revised access arrangement later this year.*[291]

In response to the Authority's final decision, we have considered and taken into account the issues raised by stakeholders. We have made further revisions to our applications and queuing policy to address the issues stakeholders raised through the Authority's consultation.

The following sections outline the:

- issues and problems that exist under the current policy
- detailed consultation that we have undertaken with our stakeholders
- key aspects and efficiency benefits of our revisions
- further revisions made to address the issues raised through the Authority's consultation

[291] Publication of *Final Decision, Western Power's Proposed Mid-Period Variation to Access Arrangement – Applications and Queuing Policy*, ERA, 1 April 2011.

Full details of the mid-term revisions that were sought during the AA2 period are provided at Appendix I: proposed mid-term revisions to the applications and queuing policy for AA2. Details of the further revisions that we have made at the Authority's request to specifically address the issues raised by stakeholders during the Authority's consultation are provided in Appendix J: Response to submissions to the proposed mid-term revisions to the applications and queuing policy.

16.3.1 Issues and problems under the existing policy

Revisions to the applications and queuing policy are required because:

- consultation to date has confirmed that the existing issues have been appropriately identified and that strong support exists for changes to be made to the policy
- we face significant challenges in undertaking applicant studies in accordance with the current policy and this is leading to delays and costs that are ultimately worn by applicants
- we have identified aspects of the current policy that lead to the use of discretion when managing the queue. We consider that a process that requires discretion over an applicant's readiness to progress is inappropriate and introduces risk both to applicants and our business
- if left unchanged, the current process will continue to distort the basis on which new generation projects can compete in the Wholesale Electricity Market
- both the Authority and the Australian Energy Market Commission have expressed concerns regarding the current applications and queuing policy – the concerns include adverse impacts on the Wholesale Electricity Market and on the commissioning of future renewable energy projects[292]

[292] The Authority has stated that the:

> *A major cause for delays in connecting new generators is the length of the network connection applications queue operated by Western Power, which generally operates on a first come first served basis. Potential generators will only receive a firm network access offer once they have moved towards the top of the queue and have then been assessed (a technical assessment to determine the costs of connecting to the network in the specified location) by Western Power and provided with an access offer. Stakeholders have in the past expressed concerns about the time taken to receive a network access offer from Western Power, which could delay participation in the RCM and possibly discourage generation investment more generally.* (*Discussion Paper: Annual Wholesale Electricity Market Report to the Minister for Energy*, ERA, 25 June 2010)

The Authority recognised that the deficiency they identify would require changes to the policy and that other changes, including to market arrangements and network planning processes, would also assist. The Australian Energy Market Commission (AEMC) has also identified issues with our applications and queuing policy. The AEMC published a Final Report in September 2009 on a review of energy market frameworks in light of climate change policy. This review included a specific review of the WA market framework. The following specific recommendation directly relevant to our applications and queuing policy was made:

> *The connections applications process should be modified in a number of ways, through the release of more information to the market, segregating applications in the connections queue on a regional basis, and potentially restructuring the connection application charge regime. The release of queue information is already under consideration, and should be implemented quickly.*

The AEMC also stated that:

> *By providing offers on a common basis to generators that are equivalent in terms of location, an efficient generation development sequence would be facilitated.*

Similarly the AEMC suggested formalising the processes for charging for shared connections so that:

16.3.2 Process for development of revisions

We undertook extensive formal review and consultation to develop revisions to address the deficiencies of our current applications and queuing policy. Our consultation process gave stakeholders the opportunity to provide submissions and discuss their views and issues at public forums and in response to the documents that we published for comment. These views and issues are incorporated in our proposed revision.

Consultation undertaken included:

- **10 August 2009** – we released a discussion paper to articulate the issues relating to the applications and queuing policy, including a series of initial proposals for discussion
- **17 August 2009** – we held a ‘queuing forum’ with a number of stakeholders in attendance
- **7 September 2009** – stakeholders were given an opportunity to provide written submissions to provide further feedback to our consultation
- **December 2009** – we published a consultation proposal which set out the issues arising with the current policy, the objectives of the review and the changes proposed. We received two submissions in response to our consultation proposal that were generally supportive. The points made and views expressed in the submissions received were taken into account in the further refinement of our revisions
- **25 November 2010** – we held a further public forum to discuss and consult on the revisions developed. Approximately 40 energy industry stakeholders attended the forum and feedback from that forum was incorporated to further refine our revisions
- **10 December 2010** – we submitted mid-term revisions to our applications and queuing policy to the Authority

Further issues were raised in response to the Authority’s formal consultation process for consideration in our revisions. We have addressed the additional issues raised by stakeholders to further refine and improve the revisions to our applications and queuing policy. The connection and access policies in other jurisdictions have also been reviewed.

16.3.3 Key aspects and efficiency benefits of our revisions

A key feature of the revision to our applications and queuing policy is its customer-driven nature. This is a distinct departure from the discretion-based approach of the current process which introduces risk and uncertainty for applicants and our business.

Through our revisions, applicants determine how they progress through the process through explicit decision stages where they lodge applications, initiate planning studies, accept/decline preliminary offers and decide whether to accept the final access offers that we make to them. Beyond these decisions the process is largely mechanical, which removes our need to exercise discretion by classifying customer applications as dormant or initiating bypass of applications to promote other applicants in the queue.

Our revisions create less need for a queue. At present there is a single queue where applicants remain in the order they arrive, regardless of their readiness to proceed to

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> *…multiple smaller generators would be more likely to be developed in a reasonable approximation of a least cost sequence.* (*Review of Energy Market Frameworks in light of Climate Change Policies – Final Report*, AEMC, 30 September 2009)

connection.[293] Instead, through our revisions, the applicants that are commercially ready with viable projects determine their own willingness to proceed, or alternatively withdraw from the process as they approach decision stages and the payment of associated fees.

The revisions to our applications and queuing policy incorporate the following key aspects:

- **the addition of a formal enquiry stage** – included to facilitate the exchange of information and to assist applicants to better indicate their requirements
- **the creation of 'competing applications groups'** (CAGs), where applicants are grouped behind common network constraints to assess and tailor joint network solutions to provide access to all applicants within the CAG – rather than the current process which provides one-off, single applicant solutions that leads to the less efficient and more costly augmentation of our network over time
- **limited use of queuing** – different pathways exist for customers with different issues. There is no longer a single queue and applicants will only queue if a particular CAG is over-subscribed.

The revisions to our applications and queuing policy process is more likely to lead to a more economically efficient connection of projects than the current AA2 process because:

- **there is a more straightforward process for applications not subject to constraints**

  Applications that are not subject to constraints from the CAG process have a more direct pathway to connection. For example, 'transfer only' or 'connection only' applications can proceed immediately to connection without being held up by applicants that sit above them in the queue that face delay due to network constraints. This creates a more efficient process for applicants that are not competing for limited capacity on the shared network.

- **work to augment the network to provide customer access occurs according to constraint/issue type rather than being driven by individual customers**

  Our revisions allocate customers with similar constraints together into CAGs so that our work can focus on resolving the common network constraint, rather than single augmentations for each individual customer. This means work to successfully resolve the constraint means many customers can move forward and if any customer wishes not to proceed they can leave the group without disrupting the others.

  Under our current approach, customers are placed in a single queue and work to connect them occurs on an individual customer basis. This can result in inefficiencies as any changes to a customer's application (for example a customer leaving the queue or not being ready to proceed) impact those in the queue behind them. This requires costly and continual study reworks to re-evaluate the queue each time a project's status changes, or if a 'queue bypass' is required when an applicant is unduly holding up others in the queue.

- **long-term strategic network augmentations deliver more efficient network outcomes**

  Grouping applicants within CAGs also provides greater scope to deliver long-term strategic network augmentations. The use of CAGs provides visibility to identify the types of constraints and number of applicants impacted and, as a result, allows planning decisions to be made that will see the greatest number of customers efficiently connected at the same time. Network augmentation in this manner is likely

[293] While a process to allow 'bypass' by later-in-time applications exists, this is cumbersome and provides discretionary powers to Western Power.

to bring about more efficient, lower cost solutions in comparison to a process which makes continuous and numerous one-off augmentations to connect individual applicants.

16.3.4 Further revisions made to address issues raised through the Authority's consultation

We have made further revisions to address the issues that led to the Authority not approving the proposed revisions. These are summarised below.

1. The 'enquiry response letter' will provide the applicant with information on capacity, known network constraints and the existence of competing applications.
2. Applicants can select their own engineering firm to undertake the necessary studies required by the applications and queuing policy process.
3. Where study costs exceed our pre-estimate, applicants will be advised before additional costs are incurred and will have the opportunity to choose their desired course of action.
4. We will inform all applicants in a CAG when an applicant-specific solution has been prepared for one of the applicants within the CAG, to provide all applicants with an opportunity to object.
5. Applicants will be advised in writing seven business days prior to a 'deemed withdrawal' as a result of their unpaid fees or charges.
6. Applicants will be able to amend their application after the applicant has received a preliminary access offer, where we agree that the amendment sought is not material.
7. When processes are commenced to develop joint network solutions for a CAG, those processes will not be interrupted by new applications except in circumstances where existing applications have withdrawn and new applications can replace the existing applications without delay to the process.
8. Timelines for various procedural steps have been inserted including:
    - the time to process enquiries (40 business days)
    - the time to resolving objections to applicant-specific solutions (40 business days)
    - indicative timeframes for our provision of preliminary and final access offers to applicants in a CAG (30 business days).

Appendix J: Response to submissions to the proposed mid-term revisions to the applications and queuing policy provides a more detailed analysis of these revisions and how we have addressed the Authority's concerns.

16.4 Contributions policy

The contributions policy specifies how and under what circumstances applicants are required to pay a contribution to the cost of works performed or costs incurred to provide access to network services.

We charge capital contributions to recover the costs to undertake work to connect customers to our network when these costs cannot be recovered through reference tariff revenue. The contributions policy details how we charge customers to recover the costs of connection *that do not meet the NFIT* at section 6.52 of the Access Code.

The capital contributions we charge are determined in line with our contributions policy.

We propose the following changes to the contributions policy:

- minor wording revisions to sections 5 and 6 of the contributions policy
- the headworks price list will be inflated on an annual basis using March on March point estimates from the ABS All Capitals CPI index rather than quarterly
- the distribution headworks methodology price list will be reviewed prior to the start of each access arrangement period rather than annually
- an outdated Government rebate subsidy scheme will be removed from appendix D of the distribution headworks methodology (DHM)

We also plan to submit an in-period (AA2) submission seeking revisions to the contribution policy to introduce a distribution low voltage connection scheme. [294]

The following sections outline these changes.

[294] Full information on the distribution low voltage connection scheme methodology will be contained in our in-period (AA2) submission. The proposals, submissions, and the Authority's decisions on access arranagement revisions are available at: http://www.erawa.com.au/3/1140/48/electricity_access__access_arrangement_variations_.pm

Access Code provisions

Section 5.12

The objectives for a contributions policy must be that:

a) *it strikes a balance between the interests of:*

  i. *contributing users; and*

  ii. *other users; and*

  iii. *consumers; and*

b) *it does not constitute an inappropriate barrier to entry.*

Section 5.13

A contributions policy must facilitate the operation of this Code, including:

a) *sections 2.10 to 2.12; and*

b) *the test in section 6.51A; and*

ba) *sections 5.14 and 5.17D; and*

c) *the regulatory test.*

Section 5.14

Subject to section 5.17A and a headworks scheme, a contributions policy:

a) *must not require a user to make a contribution in respect of any part of new facilities investment which meets the new facilities investment test; and*

b) *must not require a user to make a contribution in respect of any part of non-capital costs which would not be incurred by a service provider efficiently minimising costs; and*

c) *may only require a user to make a contribution in respect of required work; and*

d) *without limiting sections 5.14(a) and 5.14(b), must contain a mechanism designed to ensure that there is no double recovery of new facilities investment or non-capital costs.*

Section 5.15

A contributions policy must set out:

a) *the circumstances in which a contributing user may be required to make a contribution; and*

b) *the method for calculating any contribution a contributing user may be required to make; and*

c) *for any contribution:*

  i. *the terms on which a contributing user must make the contribution; or*

  ii. *a description of how the terms on which a contributing user must make the contribution are to be determined.*

16.4.1 Sections 5 and 6 of the contributions policy

For AA3 we will make minor variations to wording in section 5 and 6 of the contributions policy to clarify the calculation method for contributions payable.

Section 5 of the contributions policy describes the method to calculate contributions in respect to any works under the contributions policy. Section 6 of the contributions policy provides details on the distribution headworks methodology (DHM).

The current wording of sections 5 and 6 of the contributions policy can be improved to more clearly relate the method of calculation of contributions under the contributions policy with the operation of the DHM. Specifically, the revisions to:

- section 5 make specific reference to the:
  - DHM, to clearly articulate the linkages between the DHM and the contributions policy's calculation of the contribution payable

  - exclusion of the incremental revenue test at section 5.2(a), to make it clear that incremental revenue is only deducted at section 5.2(e) and not at section 5.2(a) as well – because this would amount to double counting

- section 6 removes reference to *deducting the amount likely to be recovered in the form of new revenue gained from providing covered services to the applicant*. The removal of this text is required to avoid an impression that the calculation of a headworks contribution (under the DHM) should deduct expected new tariff revenue from the forecast costs in the calculation of a headworks contribution. This is required because expected new tariff revenue is deducted from forecast costs in the calculation of contributions under the contributions policy and so should not also be deducted again through the DHM

16.4.2 Distribution headworks methodology

The DHM describes the approach used to determine distribution headworks charges. Section 6.2 of the contributions policy states that distribution headworks charges are required where:

> *Western Power reasonably considered that the forecast costs of headworks required for a relevant area over 25 years exceeds the amount of new revenue likely to be gained from providing covered services to applicants over that period*
>
> and
>
> *the relevant connection point is less than 160 kms from the relevant zone substation and the nominated capacity is less than 2,000 kVA, or the relevant connection point is greater than 160 kms from the relevant zone substation and the nominated capacity requirement is less than 1,000 kVA.*

The DHM is not required by the Access Code, however it is specifically referred to in section 6 of the contributions policy. No change to the fundamental operation of the DHM is recommended for AA3. The revisions propose minor changes to the headworks price list review process (section 6 of the DHM) and the removal of an outdated appendix (Appendix D). These two revisions are discussed below.

Section 6 – Headworks price list review process

Section 6 of the current DHM states that we will:

- adjust the headworks price list for CPI on a quarterly basis – section 6(a)
- review and reset the headworks price list annually based on movements in distribution construction cost estimates – section 6(b)

The current requirement to adjust prices quarterly and review cost estimates to reset prices annually is excessive given the revenue generated (around $1 to $2 million annually) and the substantial time and resources involved in conducting a review of distribution construction cost estimates. A review of the DHM's distribution construction cost estimates takes a network planner around three months to complete.

For AA3, section 6 will be revised to reflect a more appropriate price setting process, specifying that the headworks price list will be:

- **inflated for CPI on an annual basis** using March on March point estimates from the ABS All Capitals index
- **reviewed prior to the commencement of each access arrangement** period based on distribution construction cost estimates, to ensure that movements in costs or efficiencies have been accounted for within prices

These minor revisions will significantly reduce the time and resources required to adjust the headworks price list. The revisions do not represent a material departure from the DHM's current form and do not pose any NFIT implications.

The revisions to section 6 of the DHM achieve a suitable balance between the need to update prices to reflect changes in the underlying cost structures and the effort and cost involved in updating prices through the price setting process.

Appendix D – Government subsidy scheme

Appendix D of the DHM provides an overview of a Government rebate subsidy scheme to residential and commercial applications impacted by the headworks scheme that is no longer in operation.

References to this scheme will be removed from the policy for AA3.

16.4.3 Distribution low voltage connection scheme methodology

We plan to make an in-period submission during AA2 proposing revisions to the contribution policy to introduce a distribution low voltage connection scheme (DLVCS). The DLVCS is referred to in section 7 of the contributions policy. It provides a standard approach to calculating a customer contribution based on the size of a customer's load and whether a customer will have a transformer located on their property.

The DLVCS will apply to large residential houses and small to medium commercial or industrial premises. We estimate that it will be applied to between 800 and 1,000 customer connections or upgrades per year.

The mid-term revision is a result of a request by customers to review the charging policy applied to low voltage connections on the distribution network, because the current pricing approach results in variations in the required contribution for the same size load in different locations. The variation often reflects the available capacity of the network at each location.

The DLVCS will improve the simplicity and transparency of the charging regime. The proposed introduction of the DLVCS has been the subject of substantial consultation with industry, including the Minister for Energy, Office of Energy and the Authority. The supporting arrangements for the DLVCS are designed to ensure that no additional revenue is collected by our business.

We do not propose any change to DLVCS for AA3. Our access arrangement for AA3 has been prepared on the assumption that our in-period submission seeking mid-term revisions to introduce the scheme will be approved by the Authority and form part of our access arrangement in AA2.

The full details of our in-period submission seeking mid-term revisions to introduce the DLVCS will be made available on the Authority's website.[295]

16.4.4 Access Code compliance

Our revisions to the contributions policy for AA3 see no material departure to the form and operation of the policy in AA2. Our revisions:

- improve the explanation of the method used to calculate contributions to assist network users (by removing the potential to incorrectly interpret the calculation method and by better articulating linkages to the DHM)

[295] The proposals, submissions, and the Authority's decisions on access arranagement revisions are available at: http://www.erawa.com.au/3/1140/48/electricity_access__access_arrangement_variations_.pm

- revise our headworks price list review process to achieve a more appropriate price setting process
- remove an outdated appendix in the DHM that is no longer relevant

Our compliance with sections 5.12 to 5.15 of the Access Code is maintained and our policy continues to:

- balance the interests of contributing users, other users and consumers
- not constitute an inappropriate barrier to entry
- facilitate the operation of the Access Code
- not require a user to make a capital contribution for a new facilities investment that meets NFIT
- set out the circumstances where a contributing user may be required to make a capital contribution and the method for calculating the contribution
- set out the terms on which a contributing user must make a contribution or describes how the terms are to be determined

16.5 Transfer and relocation policy

The transfer and relocation policy defines the terms and conditions on which a customer may transfer or relocate contractual rights to our network services. The transfer and relocation policy provides an alternative to the applications and queuing policy, where a contractual right to network access already exists. Customers can use this policy to relocate where they access services on our network, or to transfer their contractual right to the services that they receive from their connection point to another party.

We do not propose any revisions to the transfer and relocation policy for AA3. The transfer and relocation policy has had limited use within our business during AA2 and no problems with its operation have been identified. Our consultation with major customers and energy industry stakeholders has not highlighted issues with the current form of the policy.

Access Code provisions

Section 5.18

A transfer and relocation policy

a) *must permit a user to make a bare transfer without the service provider's consent; and*

b) *may require that a transferee under a bare transfer notify the service provider of the nature of the transferred access rights before using them, but must not otherwise require notification or disclosure in respect of a bare transfer.*

Section 5.19

For a transfer other than a bare transfer, a transfer and relocation policy:

a) *must oblige the service provider to permit a user to transfer its access rights and, subject to section 5.20, may make a transfer subject to the service provider's prior consent and such conditions as the service provider may impose; and*

b) *subject to section 5.20, may specify circumstances in which consent will or will not be given, and conditions which will be imposed, under section 5.19(a).*

Section 5.20

Under a transfer and relocation policy, for a transfer other than a bare transfer, a service provider:

a) *may withhold its consent to a transfer only on reasonable commercial or technical grounds; and*

b) *may impose conditions in respect of a transfer only to the extent that they are reasonable on commercial and technical grounds.*

Section 5.21

A transfer and relocation policy:

a) *must permit a user to relocate capacity at a connection point in its access contract to another connection point in its access contract, (a "relocation") and, subject to section 5.22, may make a relocation subject to the service provider's prior consent and such conditions as the service provider may impose; and*

b) *subject to section 5.22, may specify in advance circumstances in which consent will or will not be given, and conditions which will be imposed, under section 5.21(a).*

Section 5.22

Under a transfer and relocation policy, for a relocation a service provider:

a) *must withhold its consent where consenting to a relocation would impede the ability of the service provider to provide a covered service that is sought in an access application; and*

b) *may withhold its consent to a relocation only on reasonable commercial or technical grounds; and*

c) *may impose conditions in respect of a relocation only to the extent that they are reasonable on commercial and technical grounds*.

Our transfer and relocation policy was deemed to comply with the Access Code when it formed part of our approved access arrangement in AA2. Since we seek no changes to the policy in AA3, it maintains its compliance in line with the Authority's assessment at AA2.

17 Supplementary matters

We will retain the supplementary matters provisions from AA2.

The Wholesale Electricity Market Rules are made under Part 9 of the *Electricity Industry Act 2004 and* govern the market and the operation of the South West Interconnected System, including the wholesale sale and purchase of electricity, reserve capacity and ancillary services.

The Electricity Industry Metering Code 2005 is made under Division 7 of Part 2 of the *Electricity Industry Act 2004* and is issued by the Authority. The Metering Code contains provisions governing the metering of the supply of electricity including the provision, operation and maintenance of metering equipment and ownership of and access to metering data.

Having regard to the respective obligations and purposes of the Access Code, the Metering Code and the Market Rules, we propose to continue the approaches in relation to supplementary matters as set out in the current access arrangement.

We are not aware of any other matters in respect of which arrangements must exist between a user and a service provider to enable the efficient operation of the covered network and to facilitate access to services, in accordance with the Access Code objective.

Access Code provisions

Section 5.27

Each of the following matters is a 'supplementary matter':

- a) *balancing; and*
- b) *line losses; and*
- c) *metering; and*
- d) *ancillary services; and*
- e) *stand-by; and*
- f) *trading; and*
- g) *settlement; and*
- h) *any other matter in respect of which arrangements must exist between a user and a service provider to enable the efficient operation of the covered network and to facilitate access to services, in accordance with the Code objective.*

Section 5.28

An access arrangement must deal with a supplementary matter in a manner which:

- a) *to the extent that the supplementary matter is dealt with in:*
  - i. *an enactment under Part 9 of the Act; or*
  - ii. *the 'market rules' as defined in section 121(1) of the Act,*

applying to the covered network -- is consistent with and facilitates the treatment of the supplementary matter in the enactment or market rules; and

- b) *to the extent that the supplementary matter is dealt with:*
  - i. *in a written law other than as contemplated under section 5.28(a); and*
  - ii. *in a manner which is not inconsistent with the requirement under section 5.28(a) to the extent that it applies to the covered network*

is consistent with and facilitates the treatment of the supplementary matter in the written law; and

- c) *otherwise -- in accordance with the technical rules applying to the covered network and the Code objective.*

List of Figures

List of Tables

Glossary

The following table shows a list of abbreviations and acronyms used throughout this document.

Abbreviation / Acronym	Definition
AA1	Access arrangement for the first period, 2006/07 to 2008/09
AA2	Access arrangement for the second period, 2009/10 to 2011/12
AA3	Access arrangement for the third period, 2012/13 to 2016/17
AAI	Access arrangement Information (AAI) - supporting information submitted to the ERA and published for public review.
AAI Guidelines	Guidelines to the Access Arrangement Information, published by the ERA in December 2010.
Access Code	Electricity Networks Access Code 2004
AER	Australian Energy Regulator
the Authority	Economic Regulation Authority
AWP	Approved works program
CAPM	Capital asset pricing model
CBD	Central business district
ERA	Economic Regulation Authority
FESA	Fire and Emergency Services of Western Australia
GSM	Gain sharing mechanism
GWh	Gigawatt hours
IAM	Investment adjustment mechanism
IMO	Independent Market Operator
kV	Kilovolts
kVA	Kilovolt amperes
LTIFR	Lost time injury frequency rate
MW	Megawatts
Metering Code	Electricity Industry Metering Code 2005
NFIT	New facilities investment test
PoE	Probability of exceedance
SSAM	Service standards adjustment mechanism
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
SWIN	South west interconnected network – SWIN is commonly used to describe the network portion of the SWIS.
SWIS	South west interconnected system – the SWIS includes generation plant and associated equipment.

Abbreviation / Acronym	Definition
SSB(s)	Service standard benchmark(s)
SUPP	State underground power project
Technical Rules	'Technical Rules' are the Technical Rules for the network proposed by the network service provider (Western Power) and approved by the Economic Regulation Authority under chapter 12 of the Access Code.
WACC	Weighted average cost of capital
Western Power Network	The Western Power Network is the portion of the SWIN that is owned by Western Power. The Western Power Network incorporates the integrated transmission and distribution networks. It is commonly referred to as ‘the network’ or ‘our network’ throughout this document.

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Access Arrangement Information Document Index

As per the Electricity Networks Access Code 2004 Guidelines for Access Arrangement Information (6 December 2010), requires a document index.

…the service provider must provide the Authority with a "document index" that identifies the following information for each document or group of documents

- Document title and, if applicable, document reference number/identifier
- Date of issue/publication
- A summary of the document's purpose and relevance (that is, the specific reason as to why the document has been provided)
- Page references to specific information of relevance within the document

Ref	Title	Issue Date	Grouping	Purpose and relevance	Page Ref
A	AA3 capital and operating expenditure report	30 Sep 2011	Expenditure	This report provides information on the capital and operating expenditure forecasts by regulatory category and how they comply with section 4.4.1, 4.4.3 and 5.5 of the AAI Guidelines.	All
B.1	AA2 capital expenditure report	30 Sep 2011		This document provides information on actual and forecast capital expenditure over the AA2 period to support the capital expenditure being rolled into the capital base in accordance with the new facilities investment test (NFIT) set out in sections 6.51A and 6.52 of the Access Code.	All
B.2	AA2 project and program list and variance analysis	30 Sep 2011		This document lists the projects and programs undertaken in AA2 and the reasons for variances between the forecast AA2 expenditure and the actual expenditure to support the capital expenditure being rolled into the capital base in accordance with the new facilities investment test (NFIT) set out in sections 6.51A and 6.52 of the Access Code.	All
C	AA1 speculative investment	30 Sep 2011		This document provides information to support the inclusion of speculative investment from AA1 into the opening capital base for AA3 where that expenditure meets the requirements of the new facilities investment test (NFIT) set out in section 6.51A, 6.52 and 6.60	All
D	Justification for recovery of regulated inventory costs	30 Sep 2011	Revenue	This document provides details to support the value of the inventory assets to be included in the opening capital base for AA3.	All

Ref	Title	Issue Date	Grouping	Purpose and relevance	Page Ref
E	Cost and revenue allocation method 2010/11	30 Sep 2011		This report provides the details of the cost and revenue allocation method applied in 2010/11 in preparing the regulatory financial statements, as required by section 3.5 of the AAI Guidelines.	All
F	Revenue model summary	30 Sep 2011		This is a 1 page summary of the revenue model outputs showing the total target revenue, price path and annual revenue caps (distribution, transmission and total revenue). The revenue model implements the calculations to determine the target AA3 revenue for the transmission and distribution systems in the Western Power Network	All
G	Pro forma forecast statements	30 Sep 2011		These statements provide the forecasts for AA3 expenditure and supporting information, in accordance with section 4.3.3 and the pro forma statement requirements provided in Appendix B of the AAI Guidelines.	All
H	Pro forma regulatory financial statements 2010/11	30 Sep 2011		This document provides the regulatory financial statements for the 2010/11 financial year. This is presented in accordance with section 3 and the pro forma statement requirements provided in Appendix A of the AAI Guidelines.	All
I	Proposed mid-term revisions to the applications and queuing policy for AA2	30 Sep 2011	Application and queuing policy	Our proposed mid-term revisions to the applications and queuing policy submitted to the Authority in December 2010. This report details the changes sought to improve the operations of the applications and queuing policy and is submitted under section 4.41(a) of the Access Code.	All
J	Response to submissions to the proposed mid-term revisions to the applications and queuing policy	30 Sep 2011		Our response to the public submissions on the applications and queuing policy received as a result of the Authority's notice for public submissions on the 31 January 2011.	All
K	Network investment strategy	30 Sep 2011	Strategies and plans – Network investment and management	This document provides the reasons why we invest in the network. It includes network objectives and guiding principles to consider when making investment decisions and identifies the drivers for investment. This is a key document supporting our processes for efficient planning, management and delivery.	All

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L	Network management plan	30 Sep 2011		This document provides guidance on how and when to invest in assets to maximise performance and minimise asset life-cycle costs. This is a key document supporting our processes for efficient planning, management and delivery.	All
M	Works delivery strategy	30 Sep 2011	Strategies and plans – Delivery and systems	This document sets out how we deliver network investment efficiently and in accordance with section 6.40 and 6.52 of the Access Code. This is a key document supporting our processes for efficient planning, management and delivery.	All
N	Enterprise systems asset management plan	30 Sep 2011		This document details the plan for the management of the enterprise systems to support core business processes. This is a key document supporting our corporate capital works program.	All
O	Transmission network development plan	30 Sep 2011	Planning for growth	This document sets out our 10 year transmission network development plans including the planning methodology, emerging network constraints and transmission network augmentation proposals. This is a key document supporting our processes for efficient planning, management and delivery.	All
P	System demand forecasting for AA3	30 Sep 2011		This report details our demand forecasting methodology and forecasts for the AA3 period. The network capacity to meet peak demand and its impact on the ability to connect new customers and to maintain security, reliability and quality of supply is a key consideration in our AA3 proposal.	All
Q	ROAM Report - Generation scenario development for AA3	30 Sep 2011		An independent report prepared for Western Power providing advice on generation scenarios from 2011/12 to 2020/21 that may influence development of the transmission network during and beyond the AA3 period.	All
R	Smart grid proposal	30 Sep 2011		This document explains our proposal to deploy smart technologies into the network to allow customers to better manage their electricity consumption and achieve network planning and operating efficiencies. This document supports our capital investment in distribution non-growth.	All
S	SKM/MMA report – Review of Western Power's demand forecasts for the AA3 period	30 Sep 2011	External reports – Growth forecasts	An independent review of Western Power's demand forecasting methodology and forecasts to provide assurance that the results, methods and input assumptions are robust. This document supports our peak demand forecasts for AA3.	All

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T	Deloitte report – Energy and customer number forecast for the AA3 period	30 Sep 2011		An independent report prepared for Western Power containing the detailed methodology and forecasts for energy consumption and customer numbers for the AA3 period. The report details the energy consumption and customer number forecasts used for the AA3 period.	All
U.1	Bushfire management plan	30 Sep 2011	AA2 new facilities investment	The bushfire management plan details the key bushfire management strategies relating to the Western Power Network. The purpose is to manage the risk of our network being a source of ignition and manage the risk to our network from bushfires. This is a key document supporting our safety-driven capital investment.	All
U.2	Bushfire management implementation plan	30 Sep 2011		The bushfire management implementation plan translates the bushfire management plan strategies into specific and measurable programs of work. This is a key document supporting our safety-driven capital investment.	All
V	AA2 - Report on the ERA's draft decision by Professor George Yarrow and Dr Christopher Decker, 1 Sep 2019	30 Sep 2011		An independent expert review on the *ERA's Draft decision on proposed revisions to the access arrangement for the South West Interconnected Network*. This supports the roll forward into the capital base of the capital investment incurred during the first access arrangement that was subject to a write down and meets the requirements of 6.52 and 6.60 of the Access Code.	All
W. 1	CEG Report - Western Power escalation factors	30 Sep 2011	External reports – Cost escalation and equity beta	An independent expert report prepared for Western Power to forecast labour and material cost escalators to be applied to our capital and operating expenditure forecasts for AA3.	All
W. 2	Macromonitor Report - Forecast of labour costs - Electricity, gas, water and waste services sector	30 Sep 2011		An independent expert report prepared for Western Power providing forecasts of labour costs in the electricity, gas, water and waste services sector in Western Australia. The forecast input cost escalators are applied to our capital and operating expenditure forecasts.	All
X.1	SFG report - An appropriate equity beta estimate for Western Power	30 Sep 2011		Independent expert advice prepared for Western Power on the equity beta parameter of the weighted average cost of capital (WACC). This report has informed our AA3 proposal of the WACC value with regard to section 6.4 of the Access Code.	All

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X.2	E&Y report - Advice on aspects of equity beta estimation	30 Sep 2011		Independent expert advice prepared for Western Power on the equity beta parameter of the weighted average cost of capital (WACC). This report has informed our AA3 proposal of the WACC value with regard to section 6.4 of the Access Code.	All
Y	KPMG report – Customer preferences for supply reliability survey	30 Sep 2011	External reports – Customer preferences and pricing	An independent report detailing the results of a customer preferences survey on a sample of Western Power's customers. The report provides an indication of customer preferences for different aspects of service performance. This analysis informed our service standard performance measure selection and service levels proposed for AA3 with regard to section 5.6 of the Access Code.	All
Z	Ernst & Young report - bi-directional tariff reference services and associated tariffs	30 Sep 2011		An independent review of the bi-directional reference services and associated tariffs for residential and commercial users. This review has informed our AA3 proposal for bi-directional tariffs.	All