Access arrangement information

Access arrangement revisions for the fourth access arrangement period

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Access arrangement information

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Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document. Defined terms are identified in this document by capitals.

Term	Definition
AA3	Third Access Arrangement Period
AA4	Fourth Access Arrangement Period
AA5	Fifth Access Arrangement Period
AAI	Access Arrangement Information
ACCC	Australian Competition and Consumer Commission
Access Code	Electricity Networks Access Code 2004
ACG	Allen Consulting Group
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Akaike Information Criterion
AIP	Asset Investment Planning
ALARP	As Low As Reasonably Practicable
AQP	Application and Queuing Policy
ARDS	Rules Engine
ASX	Australian Stock Exchange
ATO	Australian Taxation Office
BHM	Brailsford, Handley and Maheswaran
BTT1	Bus Tie Transformer #1
BTT2	Bus Tie Transformer #2
CAG	Competing Applications Group
CAGR	Compound Annual Growth Rate
capex	Capital expenditure
CGS	Commonwealth Government Securities
CRM	Customer Relationship Management

Term	Definition
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DBP	Dampier to Bunbury Pipeline
DEA	Data Envelope Analysis
DFA	Delegated Financial Authority
DGM	Dividend Growth Model
DLVCHS	Distribution Low Voltage Connection Headworks Scheme
DRP	Debt Risk Premium
Dx	Distribution
EMR	Electricity Market Review
ERA	Economic Regulation Authority
ETAC	Electricity Transfer and Access Contract
FMS	Field Mobility Services
FRC	Full Retail Contestability
GIA	Generator Interim Access
GSM	Gain Sharing Mechanism
IAM	Investment Adjustment Mechanism
IEEE	Institute of Electrical and Electronics Engineers
IMO	Independent Market Operator
IRC	Investment Review Committee
MRP	Market Risk Premium
MTFP	Multilateral Total Factor Productivity
MWEP	Mid-West Energy Project
NCS	Network Control Services
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NERA	NERA Economic Consulting
NFIT	New Facilities Investment Test

Term	Definition
NGL	National Gas Law
NGR	National Gas Rules
NOI	Notice of Intention
NQRS	Network Quality and Reliability of Supply
NRMT	Network Risk Management Tool
opex	Operating expenditure
PAO	Preliminary Access Offer
PFP	Partial Factor Productivity
P-P	Percentile-percentile
Q-Q	Quartile-quantile
RAB	Regulated Asset Base
RBA	Reserve Bank of Australia
RPIP	Rural Power Improvement Program
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SFA	Stochastic Frontier Analysis
SL CAPM	Sharpe-Lintner Capital Asset Pricing Model
SME	Small to Medium Enterprise
SSAM	Service Standard Adjustment Mechanism
SSB	Service Standard Benchmarks
SST	Service Standard Targets
STPIS	Service Target Performance Incentive Scheme
SUPP	State Underground Power Program
SVCs	Static Var Compensators
SWIN	South West Interconnected Network
SWIS	South West Interconnected System
TAB	Tax Asset Base

Term	Definition
Tribunal	Australian Competition Tribunal
TRIFR	Total Recordable Injury Frequency Rate
Tx	Transmission
VCR	Value of Customer Reliability
VIX	Volatility Index
WACC	Weighted Average Cost of Capital
WACOSS	WA Council of Social Service

Highlights of Western Power's proposal

$7

per year increase in Western Power's contribution to the average residential customer's bill

Maintain safety and reliability

99.9%

network reliability (average) at 30 June 2017

2,196km

of highest risk overhead wire to be replaced

Lower costs

$984M

cut in expenditure compared with AA3

24%

reduction in operating costs

New customers, new tariffs

96,000

new customers connecting 2017-22

new time of use tariffs

Executive summary

Western Power connects more than one million Western Australian homes and businesses to electricity. We do this through the vast network of poles, wires, substations and meters that we own and operate, which stretches across the south west corner of our state, bringing people the power they need.

Every five years we undertake what's known as an access arrangement review, where we revise the services we offer in relation to transmitting and distributing electricity via our network, and update the prices we charge for these services. We then submit our plans to the Economic Regulation Authority (**ERA**), who decide how much revenue is required to enable Western Power to operate and invest in the network during the next five years.

This document presents Western Power's proposed access arrangement for the **AA4** period.[1] This proposal is the fourth iteration of Western Power's access arrangement, commonly referred to as the AA4 proposal. The proposal outlines our key activities and investments over the AA4 period, and the network prices we intend to charge. The proposal also discusses what we have delivered over the previous access arrangement period (**AA3**)[2] and the improvements we have made to help keep our customers' electricity bills affordable, while maintaining network safety and reliability.

The AA4 review is an opportunity for Western Power to ensure our customers value our services and that the prices we charge for using the network are reasonable. During the course of developing the proposal, we have met and talked with customers to test our plans for the AA4 period, and to make sure the investments we make reflect what our stakeholders want. Where possible, we have built this customer feedback into our proposal, and believe we have developed a suite of access arrangement revisions that balances price impact with prudent network management, and that the ERA can reasonably approve.

Our proposal

The aim of Western Power's AA4 proposal is simple: to maintain network safety and reliability, and to do this without materially increasing customers' electricity bills. We also want to make sure our network can continue to meet the changing energy needs of Western Australians.

This means our investment proposal and revenue requirement for the AA4 period consider how we can best provide traditional network services now, and what the services we offer might look like in the future. This is particularly important as technology such as battery storage becomes mainstream.

Western Power's revenue requirement for the AA4 period is $7,888 million.[3] This includes $6,199 million of total capital investment and operating expenditure, comprising operating costs that are 24 per cent lower than in the AA3 period.[4] Our proposal also includes the introduction of new tariffs and technology that will give customers greater control over their electricity use.

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1 The AA4 period commenced 1 July 2017 and ends on 30 June 2022. However, the revised access arrangement will not take effect until the ERA has completed its AA4 review. Western Power's current prices and service levels will apply until the AA4 review process is complete, at which time any changes in Western Power's revenue requirement will be back-dated to 1 July 2017. However, any adjustment to prices will be forward-looking.

2 The AA3 period was 1 July 2012 to 30 June 2017.

3 All monetary values in this executive summary are in real dollars at 30 June 2017, unless otherwise stated.

4 The balance of the $7,888 million revenue requirements includes financing costs, tax, subsidies and a range of other costs. Details of what comprises the revenue requirements is provided in Chapter 10 of this document.

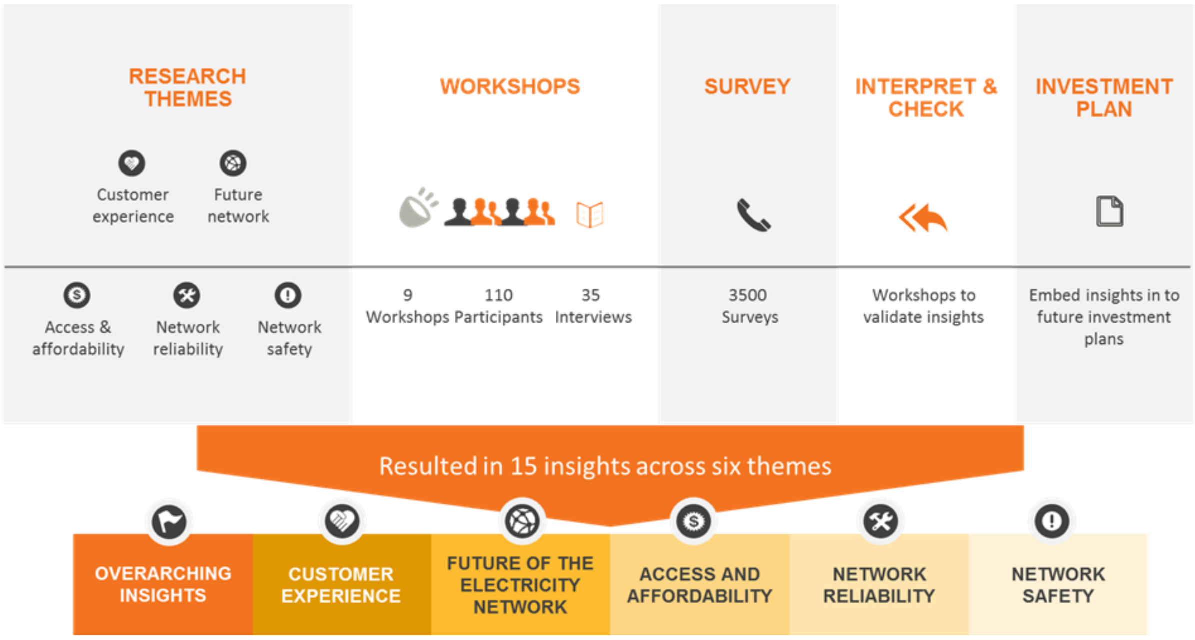
Most importantly, the impact of Western Power's AA4 proposal on electricity bills is low. We estimate the cost of supplying the average residential customer would only increase by around $7 per year[5] as a result of the new network prices. This is lower than the current rate of inflation.

Our plans for the AA4 period are shaped by improvements made over the AA3 period. The AA3 period saw Western Power undertake its largest-ever capital program, replacing and/or reinforcing more than 270,000 wooden power poles and removing all known high risk overhead customer connections and streetlight switchwire from the network. We also delivered the Mid-West Energy Project, constructing a 200 km transmission line from Pinjar to Eneabba, the largest single capital project in more than 30 years, enabling mining customers and wind farms to connect to the network.

Service performance also improved overall during the AA3 period, with the network now providing electricity 99.96 per cent of the time and call centre response times tracking at 91.8 per cent.[6] While there remain pockets of the network that require further investment, reliability of supply is generally good. Further, the business has made improvements to its structure and processes, incurring $1,481 million (17 per cent) less expenditure during AA3 than forecast, and reducing forward-looking costs. This means Western Power ended the AA3 period with a good foundation for starting the AA4 period.

A key part of Western Power's improvement in recent years has been to listen more to its customers. We have taken steps to improve our interaction and communication with customers and all our stakeholders, seeking their opinions on our plans and keeping them informed of our activities. For example, to help inform the AA4 proposal Western Power conducted a detailed customer engagement program to understand customer' views on current performance and to learn what they expect from their electricity network service provider. These engagements has helped shape our plans. Figure ES.1 provides an overview of the customer engagement program.

Figure ES.1: Overview of Western Power's customer engagement program



5 Estimated additional cost of supplying the average residential customer is $7.47 per year per customer.

6 Percentage of calls answered within 30 seconds.

The customer engagement program provided valuable insight on a range of themes from affordability to network safety. Understandably, our research found that customers are sensitive to price increases. As a result, we have been mindful of the impact on electricity prices of all our access arrangement revisions, as well as the proposal as a whole.

However, some of the more revealing insights were that customers are generally satisfied with current levels of reliability and do not necessarily want Western Power to target investment on improving overall network performance. Another valuable insight was that customers value a safe network but do not want Western Power to spend more (or less) to improve safety. They would rather Western Power targets safety expenditure in areas that carry the highest safety risk (for example high bushfire risk areas), where investment would have the greatest impact.

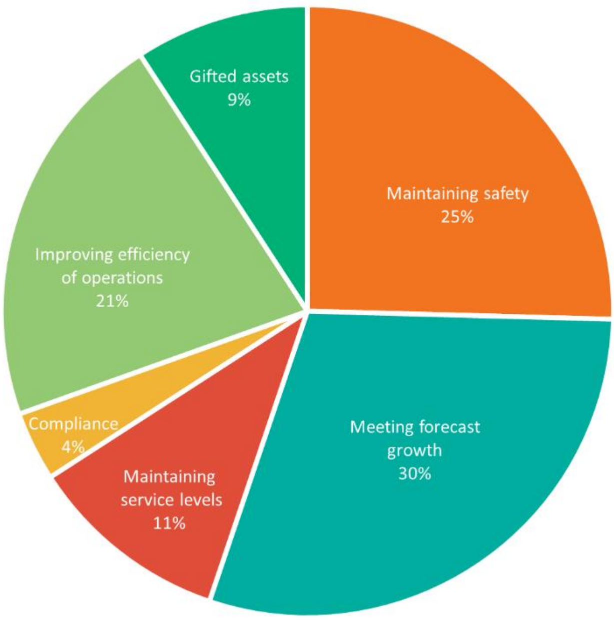
Forecast expenditure

These findings, along with the full suite of customer insights and stakeholder feedback, has influenced Western Power's expenditure plans for the AA4 period. We have substantially reduced forecast expenditure for AA4, with capital expenditure 8 per cent lower and operating expenditure 24 per cent lower than what was incurred during the AA3 period.

Our investment during the AA4 period is designed to provide services valued by customers and:

- maintain the current levels of safety risk associated with the network
- maintain current levels of service performance[7]
- meet forecast growth and demand
- satisfy compliance requirements
- continue to improve the efficiency of our operations.

Figure ES.2: Forecast capex by investment outcome



To achieve these five outcomes, we have designed a capital expenditure (**capex**) program that has low impact on prices.

Figure ES.2 shows the breakdown of how forecast capex will be used to achieve the five investment outcomes listed above.[8] We consider this forecast represents a prudent level of investment designed to keep the business operating at today's level of performance with efficient long-term asset management practices in place to ensure the network remains relevant.

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7 This includes service levels for the distribution and transmission networks (reliability of supply and security of supply), as well as call centre and streetlight performance.

8 Note 'gifted assets' shown in the chart is not an investment outcome nor capex proposed by Western Power, rather it represents the proportion of assets that are constructed by third parties and then given to Western Power to operate.

The AA4 capex program builds on the efficiency and governance improvements made over the past five years. We have also considered the impact on customers' electricity bills and the prevailing economic conditions when developing the AA4 forecast. As a result, forecast capex is significantly lower ($400 million)[9] than that incurred in the AA3 period.

As always, safety remains a major part our investment focus. Safety expenditure during the period includes replacing more than 2,100 km of the highest risk overhead conductor, and replacing or reinforcing around 125,000 wooden power poles. Our bushfire management programs will also continue, focusing on mitigating safety risks in the areas that need it the most.

Expenditure in growth-related project remains a large portion of our forecast investment. Even though overall peak demand growth has slowed in recent years, parts of the network such as Mandurah and Bunbury are still growing much faster than elsewhere. That's why we are focusing much of our growth-related investment on these thriving areas, while augmenting the broader network to ensure the 1.1 million customers connected to it, and the ~96,000 new customers expected to connect over the next five years, have a reliable electricity supply.

We're also placing much greater focus on investments that will improve the efficiency of our operations. We propose to upgrade and implement new IT and communications systems that will help us operate and manage the network more efficiently. Most of our investment to improve operations is categorised as corporate capital expenditure, and includes improvements to our depots, our network security and control systems, and the countless other things that support the distribution and transmission networks.

New technology is likely to play a significant role in the future of Western Australia's electricity systems over the coming years, and we're looking at how we can adopt emerging technology for the benefit of our customers. At the moment the majority of our expenditure forecast relates to traditional poles and wires solutions. However, the emergence of battery storage systems, microgrids and more advanced distributed generation systems, means the solutions we actually put in place tomorrow could be quite different to the plans we have developed today. Our aim will be to adopt innovation network solutions where there is a clear cost saving or benefit to customers.

During the AA3 period we commenced several trials of emerging technology, ranging from battery storage trials in Perenjori to testing a standalone power system in Ravensthorpe. The information resulting from these trials is extremely valuable; helping to inform the type of non-network solutions Western Power could offer to customers. We plan to continue trialling non-network solutions and technology over the AA4 period, and where practicable, we will implement new technology in place of traditional solutions where it is safe and more efficient to do so.

Western Power's forecast operating expenditure (**opex**) of $1,805 million is also significantly less ($584 million) than during the AA3 period (see Figure ES.3)[10].

Actual operating costs for the AA3 period were $2,389 million, which is approximately $112 million less than the forecast approved by the ERA in its AA3 decision. This saving is primarily the result of our ongoing work to improve efficiency and reduce the cost of doing business. We commenced a program of operating cost reviews at the beginning of the AA3 period, looking at our organisational model undergoing an internal restructure in 2012 and 2013. This ongoing business review continued, gathering pace in 2014 as economic conditions slowed and State Government-led reforms emerged. The review culminated in Western Power's

9 In real terms, adjusting for inflation.

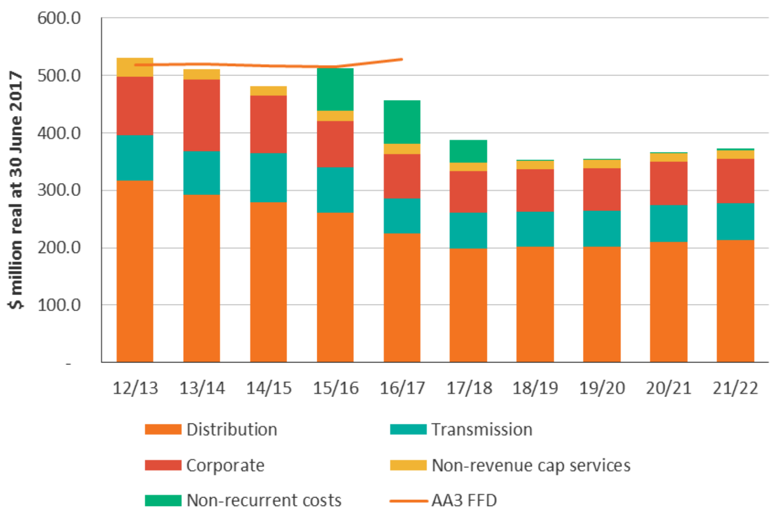
10 Includes indirect costs and escalations, $ million real at 30 June 2017.

Business Transformation Program, which commenced in 2015 and has helped reduce costs to a more efficient and long-term sustainable levels.

The benefits of Western Power's lower operating costs are being passed on to our customers through a lower 'base year' level of opex. The base year level of opex is used to determine Western Power's forecast operating costs over the AA4 period. This means that if the base year is efficient, forward-looking costs will be more efficient and network prices more affordable.

We submit actual base year (2016/17) costs that are 28 per cent lower than the 2016/17 operating costs that were forecast in the ERA's final access arrangement decision at the beginning of the AA3 period.

Figure ES.3: AA3 historical and AA4 forecast opex



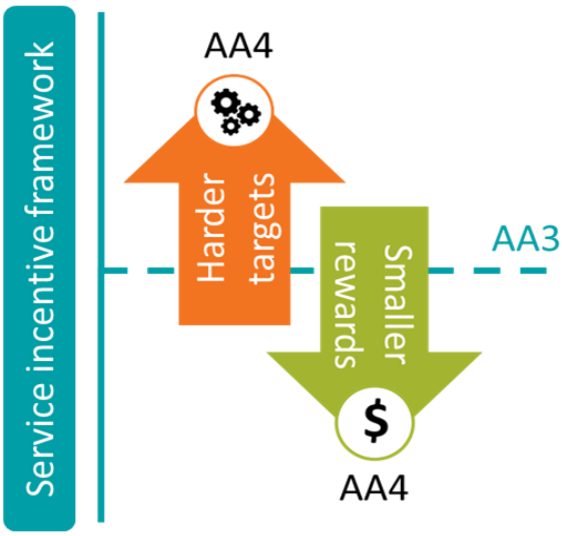
Our aim is to continue this trend of improvement over the course of the AA4 period, building more efficient processes into our business as usual activities. We expect the use of IT systems, data and technology will play a significant part in this.

Service incentive framework

Western Power has also used customer insights to inform service level targets for the AA4 period. Customers have told us they are generally satisfied with the overall service levels but believe a reliable source of electricity is essential for all customers, therefore we should focus investment on addressing localised reliability issues. They do not necessarily want Western Power to spend more money to improve network-wide reliability.

With this in mind, the service incentive framework proposed for the AA4 period is designed to consolidate the improvements made over the past five years, and maintain overall performance at the levels achieved at the end of the AA3 period. Some pockets of the network do experience poorer service than others, particularly at the edge of the grid, therefore we will target investment to improve performance in those areas. However, our proposal is that the service incentive framework be designed to provide an incentive for Western Power to keep overall performance at current levels.

Figure ES.4: Changes to AA4 service incentive framework



In most cases the targets in the service incentive framework for the AA4 period will be set at higher standards than during AA3, and will therefore be harder to achieve. This is because performance against many of the service measures improved over the course of the AA3 period, meaning today's standards are higher than those set in 2012.

We propose the size of the rewards available to the business will be smaller during the AA4 period. This, in combination with the harder targets, means Western Power has a strong incentive to maintain performance at current levels, and not specifically invest to raise performance and receive gains for improvements our customers have told us they do not consider necessary.

Weighted average cost of capital

The weighted average cost of capital (**WACC**) is the rate of return on investment a theoretical company pays (on average) to all its security holders to finance its assets. The WACC is multiplied by Western Power's capital base to give a return on assets to be included in the revenue allowance.

The costs of financing the capital investment program is a major contributor to a network business' revenue requirement. For asset-intensive businesses such as electricity networks, the return on assets is often one of the largest, if not the largest, building block used to calculate target revenue. During the AA3 period, return on assets accounted for 21 per cent ($1,380 million real as at June 2012) of Western Power's revenue.

The WACC will again be one of Western Power's largest revenue building blocks during the AA4 period. However, when developing the various financial parameters that comprise the WACC, we have been mindful of the impact of our revenue requirement on customers.

Our WACC estimate strikes a balance between recovering the business' financing costs and managing the impact on customers' electricity bills. For example, though adopting a full trailing average cost of debt would better reflect Western Power's debt portfolio, it would materially increase Western Power's revenue requirement, which would flow through to higher electricity prices. We have therefore adopted a hybrid trailing average, which softens the price impact on customers.

In addition to considering the impact on electricity bills, we are also mindful that WACC has historically been one of the most contentious areas of an access arrangement proposal, and has been the subject of many legal and limited merits reviews since 2012. We are therefore proposing a pragmatic and reasoned approach to estimating the WACC that the ERA can approve.

Our WACC estimating approach is based on that used by the ERA in its 2016 decision on the access arrangement for the Dampier to Bunbury Natural Gas Pipeline[11] (**DBNGP**). Our estimate adopts broadly the same method for determining the cost of equity and debt that the ERA applied to the DBNGP, updating individual debt and equity parameters to reflect contemporary data. We will, however, continue to monitor ongoing limited merits and judicial reviews, and modify our proposal to reflect appeal outcomes where appropriate.

Western Power's estimated WACC is 6.09 per cent, comprising a nominal post tax cost of equity of 7.24 per cent and a nominal cost of debt of 5.32 per cent.

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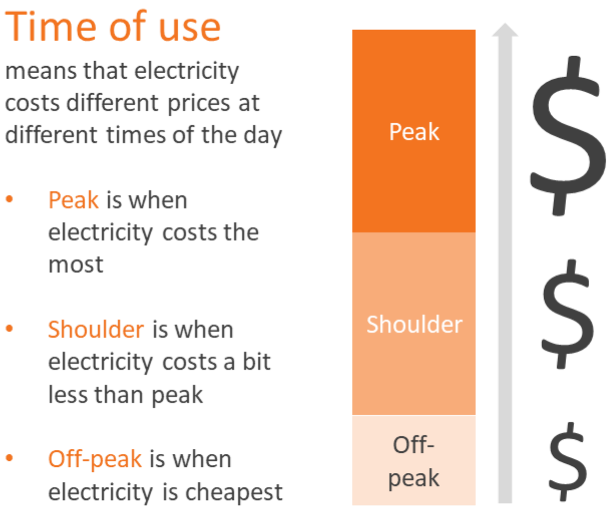
11 Appendix 4 Rate of Return, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, ERA, 30 June 2016.

Time of use tariffs

During the AA4 period Western Power is reviewing the way it charges customers. One of the things we're looking at is offering residential and small business customers the option of time of use network tariffs.

A time of use network tariff is where customers pay a different price for using electricity at different times of the day. Currently, the majority of residential customers pay a flat rate no matter what time of day or night they use electricity. A time of use network tariff would charge a higher rate at peak times (typically late afternoon and early evening on weekdays) and a lower rate at all other times.

Figure ES.5: Time of use tariff structure



The purpose of a time of use tariff is to encourage customers to spread their electricity use over the course of the day. At the moment, residential customers tend to use the most amount of electricity between 3:00 PM and 9:00 PM on a weekday, with usage peaking on the hottest summer days. We call this the network peak.

To make sure the network can cope with the peak (and so customers don't lose power), Western Power needs to reinforce and increase the capacity of the network. With a new substation costing around $45 million[12], investment in increasing network capacity can be very expensive.

Time of use tariffs are a potential alternative to the costly option of increasing network capacity. By encouraging customers to use electricity outside of peak times, the tariffs can help reduce the need for network capacity expansion, which saves customers money over the long term. Time of use tariffs can also help customers save money directly, as it provides greater opportunity to control costs by making just a few moderate changes to when and how they use electricity.

Feedback from customers on time of use tariffs has been positive. Customer forums and surveys conducted during 2016 show customers are generally willing to change their electricity usage behaviours upon understanding the impact of peak demand. There is also appetite for time of use tariffs, particularly among younger customers.

Western Power proposes to work with Synergy (and other residential retailers in the future[13]) to help ensure network and retail tariffs are aligned, and customers are fully informed of the benefits of moving to time of use tariffs.

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12 Based on estimated cost of replacing the Mandurah substation.

13 Synergy is currently the principal retailer for residential customers. Should the retail market become fully contestable, Western Power is committed to working equitably with all retailers that enter the WA market.

Advanced metering infrastructure

During the AA4 period, we are proposing to increase the prevalence of advanced metering infrastructure across the network. Advanced meters are electronic meters that provide a multitude of connection point interval datasets and real-time alarms to Western Power, which can be used to deliver a range of customer, network service and market benefits.

Having remote visibility of data and alarms at the connection point means Western Power can reduce network and metering costs over time. At the most basic level, advanced metering infrastructure reduces the cost of meter reading, and other metering services such as re-energisation, as these functions can be conducted remotely, at lower cost and in a timelier manner.

The greatest benefits result from use of the data advanced metering can provide, a particularly data on asset condition and performance. For example, advanced metering infrastructure allows us to monitor the condition and performance of customer service connections, and identify the most prudent and efficient time to replace and/or repair these assets. This valuable asset data allows us to forecast works much more accurately, potentially saving millions of dollars each year, whilst continuing to minimise safety risks. Advanced metering infrastructure also enables time of use tariffs to be implemented, which as described above, can help manage the network peak and reduce the need for costly network capacity investment. All these benefits help manage the cost of operating and investing in the network, which translates into lower network tariffs and more affordable electricity bills for customers.

Western Power is not proposing a widespread roll-out of advanced meters. We consider it more prudent to introduce advanced metering infrastructure as part of the standard meter replacement program. During the AA4 period we will install around 355,000 advanced meters, as the default replacement for meters that are forecast for replacement over the next five years as well as new connections to the network and retailer requested replacements (e.g. where a customer installs a solar PV system and requires a bi-directional service). Customers whose meters are not scheduled for replacement during the AA4 period will have the option to request an advanced meter if they wish, with a fee applicable.[14]

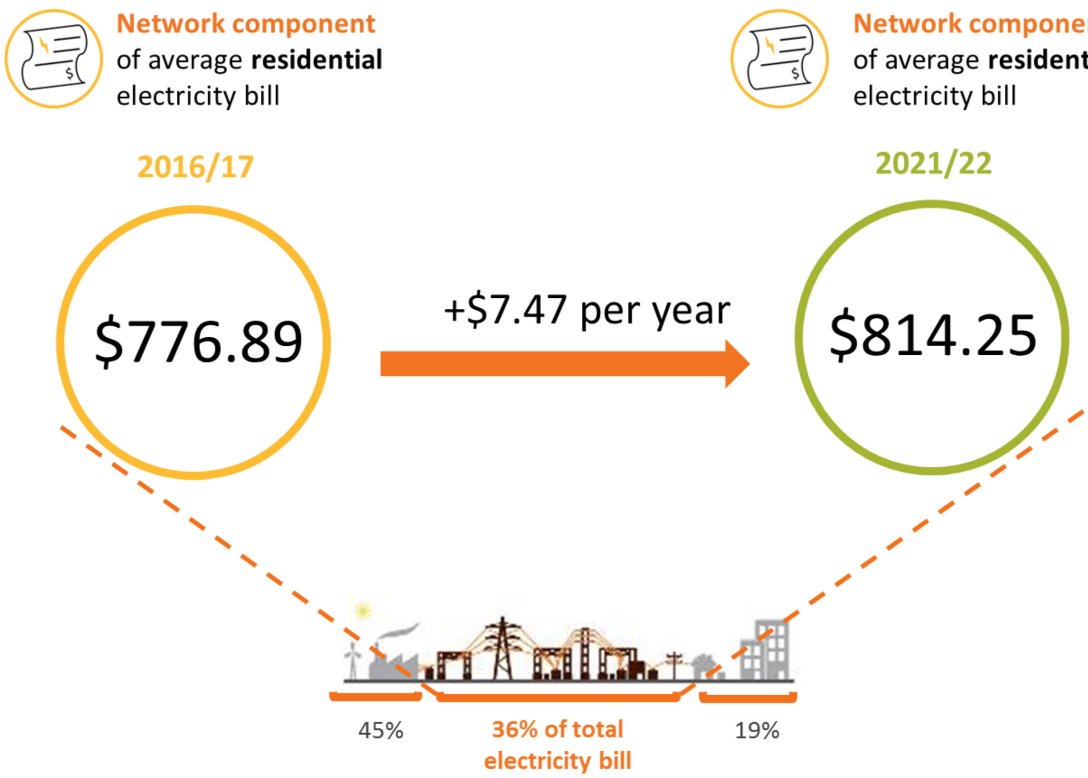
What our AA4 proposal will cost

The AA4 proposal results in target revenue of $7,888 million. Though this is a 7 per cent revenue increase in real terms, the impact on prices is low.

Western Power's costs account for approximately one third of the electricity bill paid by customers. Based on an average residential customers' annual usage (currently around 5,200 kWh of electricity per year) the network component of the average residential electricity bill will increase by approximately $37 over the five years of the AA4 period.

[14] Western Power is also proposing updates to the Metering Model Service Level Agreement, which defines charges to Code Participants for metering services, including meter exchanges.

Figure ES.6: Estimated impact of revised network charges on the average residential electricity bill



Error! Reference source not found. shows the estimated movements in electricity bills over the AA4 period if Western Power's AA4 proposal is approved and implemented in full. Note these figures are based on average annual usage in each customer class, and relate to the network tariff only. Western Power has no control over the electricity generation costs or how much of any cost savings or increases are passed on to the customer by electricity retailers.

Table ES.1: Estimated annual change in average electricity bills resulting from AA4 proposal, nominal per cent per annum

Customer type	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Residential	0.0%	2.5%	2.0%	1.4%	1.6%	0.9%
Small business	0.0%	4.0%	3. 3%	2.7%	2.9%	2.3%
All distribution customers	0.0%	19%	1.0%	0.5%	0.8%	0.3%
All transmission customers	0.0%	9.8%	9.8%	9.2%	8.8%	7.4%
All customers	**0.0%**	**3.0%**	**2.4%**	**1.9%**	**2.1%**	**1.3%**

The estimated impact on residential bills is around +0.9 per cent per year, which is lower than the current inflation rate. This equates to an increase of $7.47 per year over the AA4 period.

The increase for transmission customers is larger, however, it follows annual average decreases of around 7 per cent (nominal) in transmission network tariffs over the past five years. We are mindful of the impact on transmission customers (typically large business and major industrial customers) and have proposed a solution that keeps the transmission price increase below 10 per cent (nominal) per year. Our transmission pricing solution involves deferring collection of more than $230 million of transmission revenue for collection in future access arrangement periods, and bringing forward collection of distribution revenue. This treatment of deferred revenue helps manage the potential for price shock to transmission customers, which otherwise could be as high as 18 per cent per year if we recover forecast transmission revenue in full. This complex issue and transmission pricing proposal is discussed in detail in Chapter 11 and in the transmission pricing document provided in Attachment 10.8.

Why our proposal is efficient

Figure ES.7: Factors driving Western Power's efficiency

Western Power's aim is to achieve an access arrangement that is balanced, reasonable and equitable. We are aware of the slower economic conditions in Western Australia compared to the past highs of the mining boom, and we understand how price increases can affect customers. We have taken steps to lessen the impact of our activities during the AA4 period, particularly on residential customers who we know are feeling the economic impact more than most.

We're doing this by making sure our investment is prudent and our costs are efficient. A key part of Western Power's corporate strategy in recent years has been to become more customer focused, and the customer engagement program we undertook to help inform our plans is one example of that. One of the most important improvements at Western Power in recent times was the whole of business review undertaken in light of customer expectations and the changing economic environment.

The Business Transformation Program is Western Power's response to the changes that occurred in the energy market over the AA3 period. At the beginning of the AA3 period (2012/13) substantial energy demand growth was forecast, and Western Power's operating and maintenance program was designed to support a network providing energy to a growing customer base.

Over the course of the period, a combination of factors including WA's economic slowdown, the impact of new technologies, and changing customer behaviour, meant forecast growth did not materialise. In addition, the State Government's Electricity Market Review provided a catalyst for organisational change.

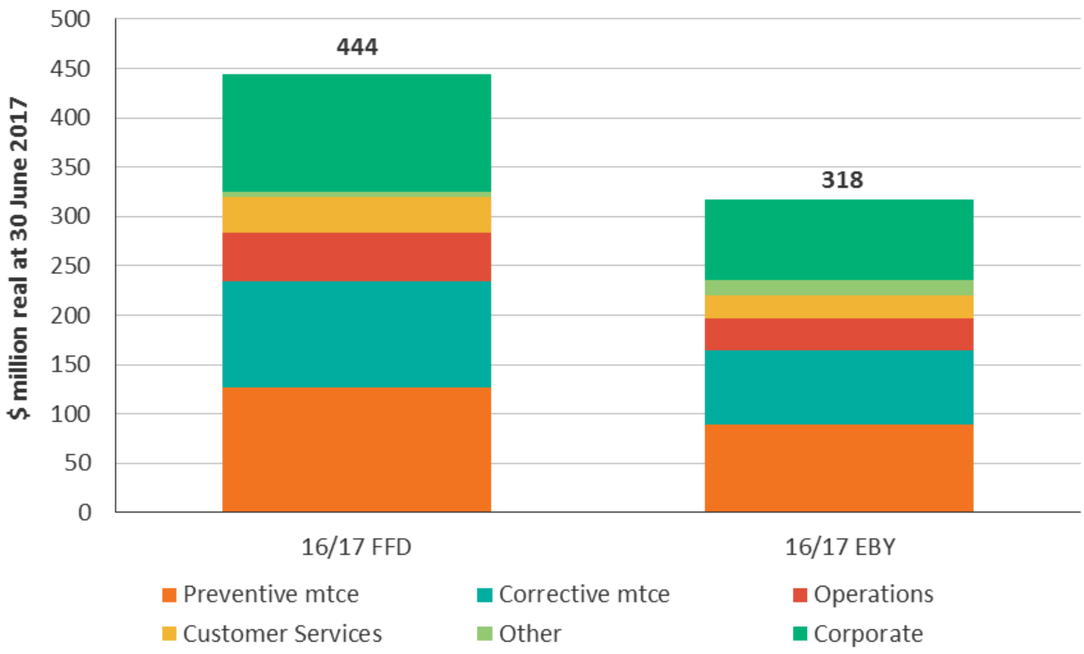
Rather than assume the expenditure program developed as part of the AA3 process would remain the optimal approach for the period, Western Power commenced a comprehensive review of its operating costs and investment activities.

The Business Transformation Program has delivered $330 million of recurrent cost savings to date.[15] Improvements to Western Power's asset strategies, procurement processes, and work practices mean we have rationalised our operating costs to a point where we expect to be able to maintain current service levels in a more cost effective way. The impact of our focus on reducing operating costs can be seen if we

15 30 June 2017. This includes both capex and opex.

compare the actual base year opex for 2016/17 with the 2016/17 base year forecast that was approved in the AA3 final decision in 2012.

Figure ES.8: Efficient base year compared to AA3 further final decision, $ million real at 30 June 2017



Our base year costs have reduced by more than $120 million (28 per cent). This means we begin the AA4 period with a significantly more efficient level of opex than previously forecast, highlighting the improvements made over the course of the AA3 period.

The Business Transformation Program will continue into 2018, and we expect to achieve further efficiencies over the course of the AA4 period. Many of these efficiencies will be driven by investment in new technology, systems, and ongoing changes to our internal processes and asset management approach. This continued focus on efficiency improvement is what is helping drive our lower opex and capex programs over the next five years. As a result, customers can be confident that Western Power's AA4 proposal is efficient.

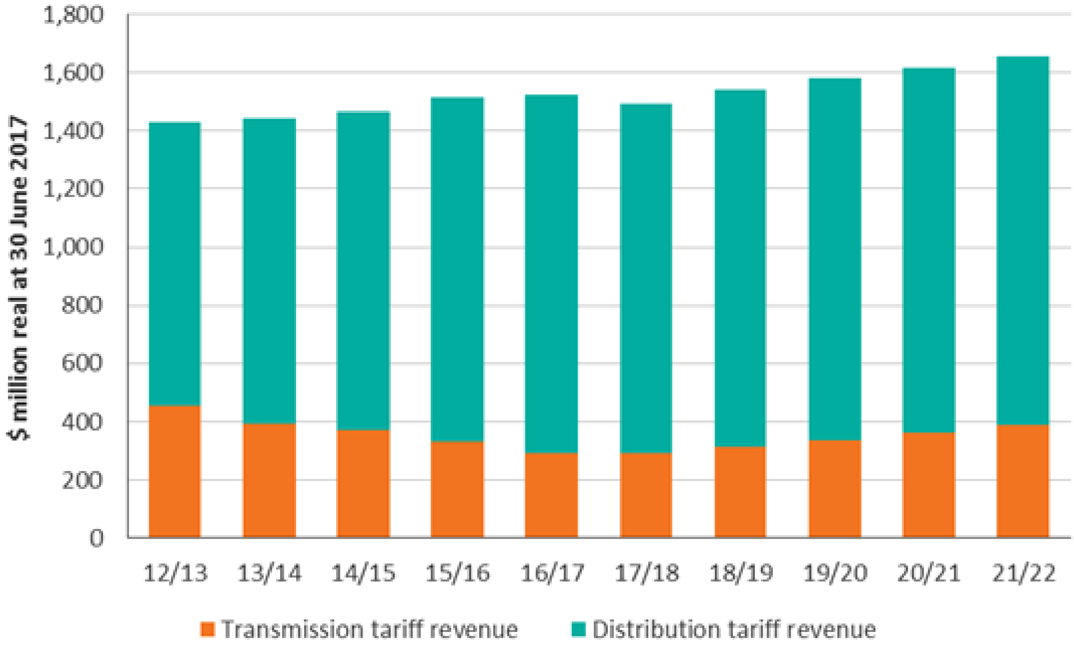
Summary of AA4 target revenue

Western Power will recover $7,888 million of revenue via reference tariffs during the AA4 period. This is $510 million (6.9 per cent) more than tariff revenue recovered during the AA3 period.

Table ES.2: AA4 target revenue, $ million real at 30 June 2017

Target revenue	AA4 period (proposed)
Transmission tariff revenue	1,687.4
Distribution tariff revenue	6,200.3
Total	**7,887.7**

Figure ES.9: Comparison of target revenue for the AA3 and AA4 periods, $ million real at 30 June 2017



1. About this submission

1. This chapter outlines the structure of this submission document, its relationship to the Western Power access arrangement for the regulated or 'covered' Western Power Network, and how the proposed revisions to the access arrangement for the fourth access arrangement period (referred to as the AA4 proposal) were developed. The chapter provides:

   - an overview of the key *Electricity Networks Access Code 2004* (**Access Code**) provisions relevant to producing access arrangement information (**AAI**)
   - a summary of the approach Western Power adopted, and its key considerations when developing this initial proposal
   - a revisions submission date and targeted revisions commencement date for the following access arrangement period (**AA5**)
   - a summary of the document structure and the information contained in each section.

2. Western Power's access arrangement defines the prices, terms and conditions for accessing the Western Power Network and is subject to periodic review by the Economic Regulation Authority (**ERA**).

1.1 Access Code provisions

3. In accordance with section 4.48 of the Access Code, this document comprises the AAI for consideration by the ERA. The AAI is the supporting information required by the ERA to assist in understanding Western Power's access arrangement and target revenue proposal, and the underlying assumptions of that proposal.

4. As required by section 4.2 and 4.3 of the Access Code, the AAI has been written to enable the ERA, Western Power customers and other interested stakeholders to:

   - understand how Western Power derived the elements that make up the proposed access arrangement
   - form an opinion on whether the proposed access arrangement complies with the Access Code.

5. The AAI includes information on the form of price control, pricing methods, total costs, capacity and volume assumptions, service standards, incentive mechanisms, and other evidence that demonstrates how the AA4 proposal complies with the Access Code.

1.1.1 Access Code objective

6. Western Power operates its network in accordance with the Access Code objective, which 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.[16]

[16] Section 2.1, *Electricity Networks Access Code 2004*.

7. The AA4 proposal is designed to ensure Western Power continues to satisfy the Access Code objective. We believe that to do this, Western Power must:

- ensure prices are kept to the lowest sustainable level for an efficient business
- deliver a level of service that meets our customer's needs
- provide services that are safe, reliable and efficient
- adapt tariffs and services to changing market conditions.

8. We have provided evidence to demonstrate how our proposal will deliver these outcomes over the AA4 period and beyond.

9. While the Access Code objective guides the overall proposal, there are also specific objectives that apply to certain elements of the AAI. To assist the reader, we have referenced relevant sections of the Access Code throughout this document.

1.1.2 Preparing a balanced and reasonable proposal

10. This AA4 proposal covers the fourth access arrangement period[17] (referred to as the AA4 period), which as proposed in section 1.1.5 below, will apply for the five-year period 1 July 2017 to 30 June 2022[18]. We have prepared this AA4 proposal using the best and most reliable information available at the time of submission.

11. Western Power's aim is to submit a balanced and reasonable proposal that satisfies the Access Code objective and manages the price impact on customers. The AA4 proposal has been developed to align with our customers' expectations and ongoing energy market reform. As such, the changes to the access arrangement are pragmatic, forward-looking and underpinned by a recent program of efficiency improvement at Western Power. Most significantly, our proposal results in a small increase in average network tariffs.

12. We expect the ERA to make a final decision (further final decision) on the AA4 proposal by mid-2018. We appreciate it will be almost a year into the AA4 period by the time the revised access arrangement is in place. Therefore in accordance with section 4.6 of the Access Code, the prices, terms and conditions (including service standards) defined by the current access arrangement will continue until the ERA makes its final decision and the revised access arrangement has commenced.

1.1.2.1 A proposal informed by customer engagement

13. To ensure the revised access arrangement continues to meet the Access Code objective, it is paramount the services we provide, and what we spend to provide those services, reflects what our customers need, want and are willing to pay. It is for this reason that the AA4 proposal has been informed by a detailed customer engagement program.

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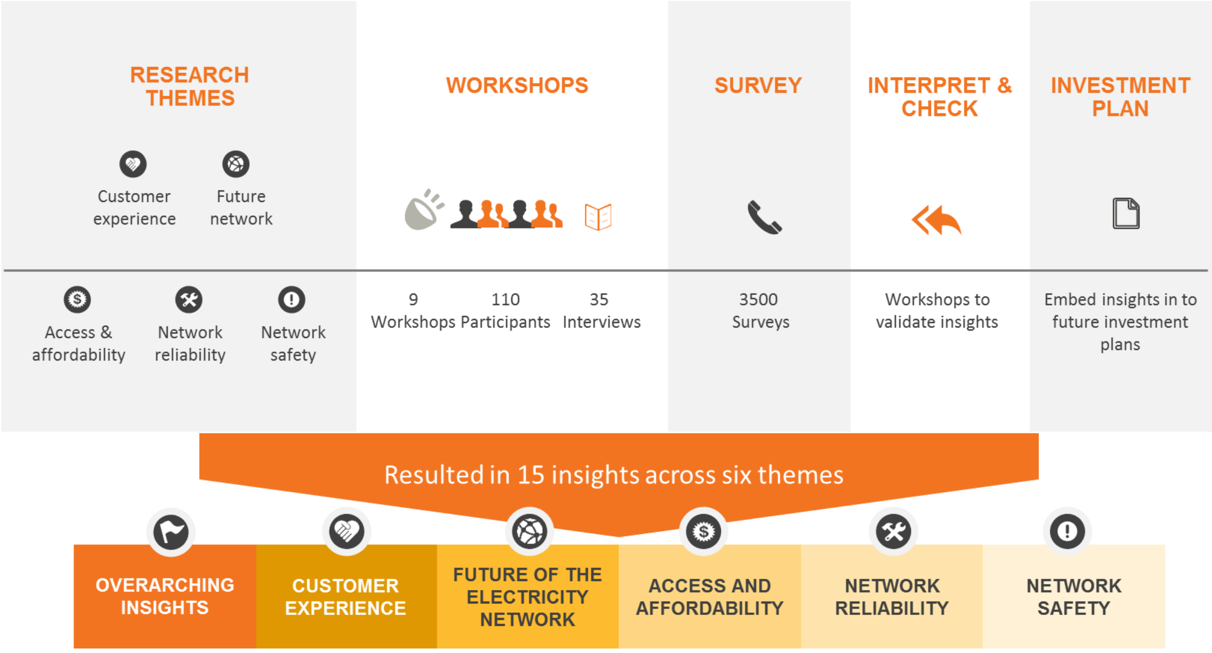
17 The first access arrangement commenced in 2006, following the disaggregation of Western Power Corporation. The AA4 period represents the fourth iteration of the access arrangement.

18 The AA4 period commenced 1 July 2017 and ends on 30 June 2022. However, the revised access arrangement will not take effect until the ERA has completed its AA4 review. Western Power's current prices and service levels will apply until the AA4 review process is complete, at which time any changes in Western Power's revenue requirement will be back dated to 1 July 2017. However, any adjustment to prices will be forward-looking.

14. Between 2015 and 2017 we conducted a series of customer and stakeholder workshops, which provided valuable context for our AA4 proposal. Detailed information on the customer engagement program is provided in Chapter 4. Figure 1.1 summarises our engagement approach.

Figure 1.1: Customer engagement program overview



15. Insights from the customer engagement program have shaped our thinking on the services we will provide and the technology we will invest in over the AA4 period. For example, customers have told us they don't necessarily want us to improve overall levels of reliability, but they are happy for us to target expenditure on pockets of the network where reliability is lower than average – so all customers receive a reliable source of electricity.

16. Customers have also told us that they would consider new network tariff structures, such as time of use tariffs, if more information is provided about how they work and how customers would benefit. They also expect Western Power to invest in new technologies that are effective alternatives to traditional network solutions.

17. We also engaged with electricity retailers and generators via a series of forums held during 2017. Generators and retailers provided feedback on the access arrangement and proposed new tariff structures, which we have taken into account when preparing our AA4 proposal.

18. Commentary on how customer feedback has influenced our expenditure is provided throughout the operating and capital expenditure proposals outlined in this document.

1.1.2.2 A proposal founded on efficiency improvements

19. Over the course of the AA3 period (1 July 2012 to 30 June 2017), we have sought process and productivity improvements that achieve genuine efficiencies, without compromising the quality of service to customers. As a result, our actual operating and capital costs during the period are substantially lower than the AA3 period forecast.

20. In 2011/12 Western Power developed an expenditure forecast for the AA3 period. That forecast was based on the best information available and market conditions of the time, and was subject to a lengthy review

process with the ERA and stakeholders. The expenditure forecast was approved by the ERA in November 2012.

21. Western Power commenced the expenditure program for the AA3 period in 2012, and began delivering the works program as planned. As part of its annual business planning process, Western Power conducts a review of forecast expenditure. The purpose of the expenditure review is to test whether proposed investment plans remain prudent.

22. Rather than assume the capital and operating expenditure forecasts approved at the beginning of an access arrangement period remain the optimal expenditure profile for the full five years, we look at changes in the energy sector, emerging technology, and our customers' expectations, and adjust our investment plans accordingly. Early in the AA3 period it became clear that forecast growth in electricity consumption was not materialising. The WA economy had slowed and energy reforms were being proposed by the State Government. In addition, a parliamentary inquiry in to the management of wooden power poles imposed new requirements on the business, placing greater emphasis on high volume asset reinforcement and renewal.

23. Western Power responded by re-thinking its plans for the AA3 period (and beyond), and looking at ways to reduce expenditure without compromising safety or quality of service. We also looked at our operations to understand where we could become more efficient, and bring the cost of operating and investing in the network to a sustainable level within the new circumstances.

24. Over the past two years, by improving our asset strategies, procurement processes and work practices, we have rationalised our operating costs. As such, we expect to be able to maintain current service levels throughout the AA4 period via a more efficient level of expenditure.

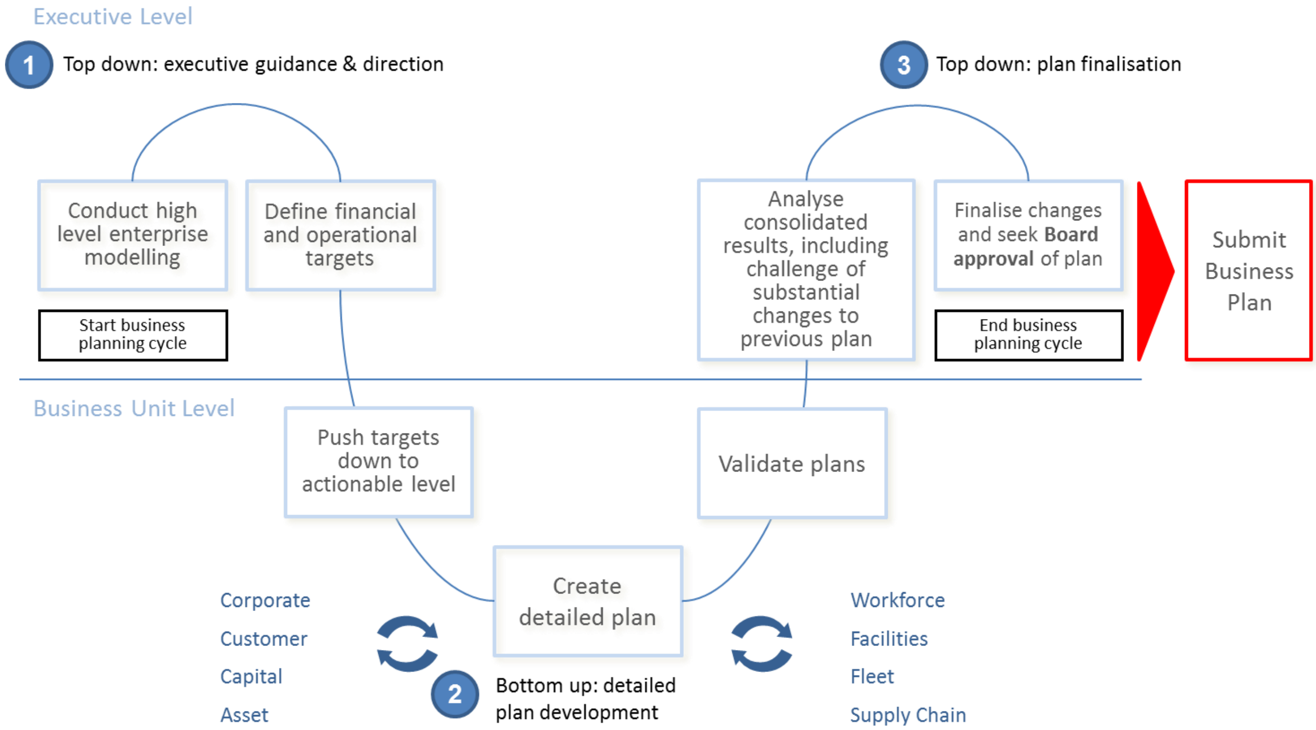
25. Better asset information and refined assumptions on the timing of some of our asset replacement programs also means we reduced our capital expenditure during the AA3 period. As such, Western Power enters the AA4 period with an investment program that better reflects the energy requirements and customer expectations of today.

26. As a result, we submit an expenditure forecast in this AA4 proposal that is credible, represents the lowest sustainable (long-term efficient) cost, and can be approved by the ERA. Information on our efficiency improvements is provided in Chapters 3, 7 and 8.

1.1.2.3 A proposal subjected to rigorous challenge

27. The information, estimates, and forecasts used in this AA4 proposal have been subject to a rigorous verification process and 'top-down' challenge. For example, the expenditure forecasts in this proposal were drawn from Western Power's annual business planning process, which generates a rolling 10-year business plan. Figure 1.2 summarises the standard top-down – bottom-up – top-down approach we take to business planning and investment governance.

Figure 1.2: Western Power's business planning approach



28. It is important to note that this access arrangement proposal builds on improvements made to business processes in recent years, and draws heavily on what are now 'business-as-usual' governance activities. The 10-Year Business Plan and its annual development is one example. During the AA3 period we have refined our asset management system and have a suite of strategic documents that are used to develop our ongoing plans outside of an access arrangement review. The Network Management Plan and Network Development Plan (see Attachment 1.1 and 1.2 respectively) are key inputs that are refined and scrutinised annually, which means the information in this AA4 proposal has already been subject to considerable challenge.

29. In addition to Western Power's business-as-usual business planning and governance practices, our AA4 proposal has been subjected to additional scrutiny. Key features of this include that:

- forecasts and historical expenditure are based on robust business cases[19], which have been reviewed for compliance with the Access Code objective and sections 6.52 and 6.40 of the Access Code
- all relevant drivers of a particular forecast have been taken into account, and the underlying data used to derive forecasts is provided with this proposal
- we have used independent expert advice to prepare some of our forecast information.

1.1.3 Information used in this proposal

30. The historical information used in this initial proposal is the most recent actual information available at the time of developing the submission.

[19] For those that have reached this point in the investment governance process.

31. A summary of the key assumptions used in this AA4 proposal is listed below.

- operating expenditure base year is set using audited full year 2016/17 actuals
- capital expenditure forecasts have been developed using Western Power's 2016 peak demand, energy consumption, and customer number forecasts, adjusted for key changes resulting from 2017 updates
- AA3 capital and operating expenditure is reported as audited full 2012/13 to 2016/17 actuals
- expenditure forecasts are prepared in real dollars at 30 June 2017
- labour input costs are as per the independent expert report, prepared in May 2017
- material cost escalation are assumed at 0 per cent
- average labour and embedded contractor component of 40 per cent is based on actual data 2014/15 to 2016/17
- network metric forecast assumptions are from 2016/17 to 2021/22, for use in operating expenditure output growth calculations
- shared network and corporate costs are allocated as per the cost and revenue allocation method
- where the WACC parameters require an averaging period to be used, we have used the 20 days to 30 June 2017.

32. Western Power's audited regulatory financial statements are provided in Attachment 1.3.

1.1.4 Use of real and nominal dollars

- All forecast and past expenditure values are expressed in real dollars at 30 June 2017 unless otherwise stated
- All revenue amounts are expressed in nominal dollars unless otherwise stated
- Some tables may not add due to rounding.

1.1.5 Length of the access arrangement period

33. Under section 5.31 of the Access Code, the length of the forthcoming access arrangement period is established by Western Power proposing a revisions submission date and a targeted revisions commencement date for the following regulatory period (AA5).

34. Western Power proposes the **revisions commencement date** for the revisions set out in the AA4 proposal be **1 July 2018**.

35. Western Power proposes that the **AA5 revisions submission date is 1 March 2021** and the access arrangement targeted revisions commencement date is 1 July 2022.

36. This results in a five-year AA4 period from 1 July 2017 to 30 June 2022.

37. The proposed revisions submission date for AA5 allows 15 months to conduct the access arrangement review process for the AA5 period. This should provide sufficient time for the ERA and Western Power to complete the review and implement any changes in preparation for the commencement of AA5.

1.1.6 Structure of this proposal

38. The structure and content of this proposal is informed by the *ERA's Guidelines for Access Arrangement Information*. Capital and operating expenditure forecasts were developed in accordance with sections 4.41, 4.43 and 5.5 of the ERA's guidelines.

39. This document (which, along with the attachments and associated expert reports, forms the AAI) should be read in conjunction with the proposed access arrangement itself.

Table 1.1: Structure of this proposal

Chapter	Summary of content
1. About this submission	• An overview of how this access arrangement revisions submission was developed, including inputs and assumptions used in the various forecasts. This section also defines the length of the AA4 period, and the AA5 revisions submission and commencement date
2. About Western Power	• An overview of Western Power network characteristics
3. Changes in the energy market	• A description of changes in the energy market that occurred during the AA3 period, and how these changes have informed Western Power's access arrangement revisions. This includes the Electricity Market Review, emerging technology, and Western Power's business transformation program
4. Engagement with customers, stakeholders and the community	• A description of the community engagement program Western Power undertook between 2015 and 2017, the results of which have informed this access arrangement revisions proposal
5. AA3 Review	• A description of Western Power's service performance and expenditure during the AA3 period
6. Regulation, incentive schemes and adjustment mechanisms	• A description of the services Western Power proposes to provide during the AA4 period, including the regulatory and incentive mechanisms that will apply. These are the gain sharing mechanism, service standard adjustment mechanisms, investment adjustment mechanisms, and D-Factor. This chapter also includes Western Power's energy demand and customer number forecasts
7. Forecast operating expenditure	• A description of Western Power's proposed operating expenditure for the AA4 period and the methodology used to forecast it
8. Forecast capital expenditure	• A description of Western Power's proposed capital expenditure for the AA4 period and the methodology used to forecast it

Chapter	Summary of content
9. Weighted average cost of capital	• A description of Western Power's estimating methodology for the regulatory WACC to apply for the AA4 period. The chapter includes Western Power's WACC parameter estimates and evidence to support these
10. Revenue	• A description of the form of regulation that will apply during the AA4 period and the revenue building blocks used to determine the AA4 target revenue. This chapter includes Western Power's forecast capital base, equity raising costs, an adjustment for performance under AA3 period regulatory incentive mechanisms, and working capital
11. Network pricing	• A description of the transmission and distribution network tariffs that will apply during the AA4 period, including how these tariffs have been determined and the overall tariff path for the period
12. Policies and contracts	• A description of any revisions to the policies, contracts and reference services associated with the access arrangement. This includes the standard access contract, Applications and Queueing Policy, Transfer and Relocation Policy, and Contributions Policy
13. Supplementary matters	• A list of supplementary matters required by the Access Code, and how they relate to Western Power

2. About Western Power

40. This chapter provides an overview of Western Power, its services, and the electricity (transmission and distribution) networks it owns and operates, which for the purposes of the access arrangement is known as the Western Power Network.

2.1 What we do

41. Electricity is fundamental to the way we all live. At home and at work, in schools and hospitals, in cities and in the country so much of our lifestyle today and tomorrow depends on a safe and reliable electricity supply.

42. At Western Power, we work hard to make sure people can continue to enjoy this lifestyle. Whether it's powering an electric car, charging your smart phone, running an air-conditioner, or helping to drive the economy, our network connects Western Australians to the electricity they need.

43. Western Power connects more than one million homes and businesses across the south west of Western Australia. We own and operate networks that comprise more than 101,000km of powerlines, more than 816,000 poles, 19,500 substations and 260,000 streetlights, over an area larger than the United Kingdom. Our job is to grow, maintain and replace these assets prudently and efficiently. We also own, install and read the meters that measure and record how much electricity our customers use, and provide this metering data to the market.

44. We move electricity from place to place – this is called transmission and distribution. We do not generate electricity. We do not sell electricity. Our services cover the 'middle part' of the electricity supply chain (see Figure 2.1).

45. The electricity created by generators is transported via the Western Power Network to customers. That electricity is purchased by electricity retailers from the generators and sold by the retailers to customers. The retailers are responsible for administering customer accounts and issuing electricity bills to customers.

46. Western Power's services are paid for via the electricity network tariff, which forms part of the overall tariff charged by retailers. Western Power's costs account for around 36 per cent[20] of the average residential customer's electricity bill.

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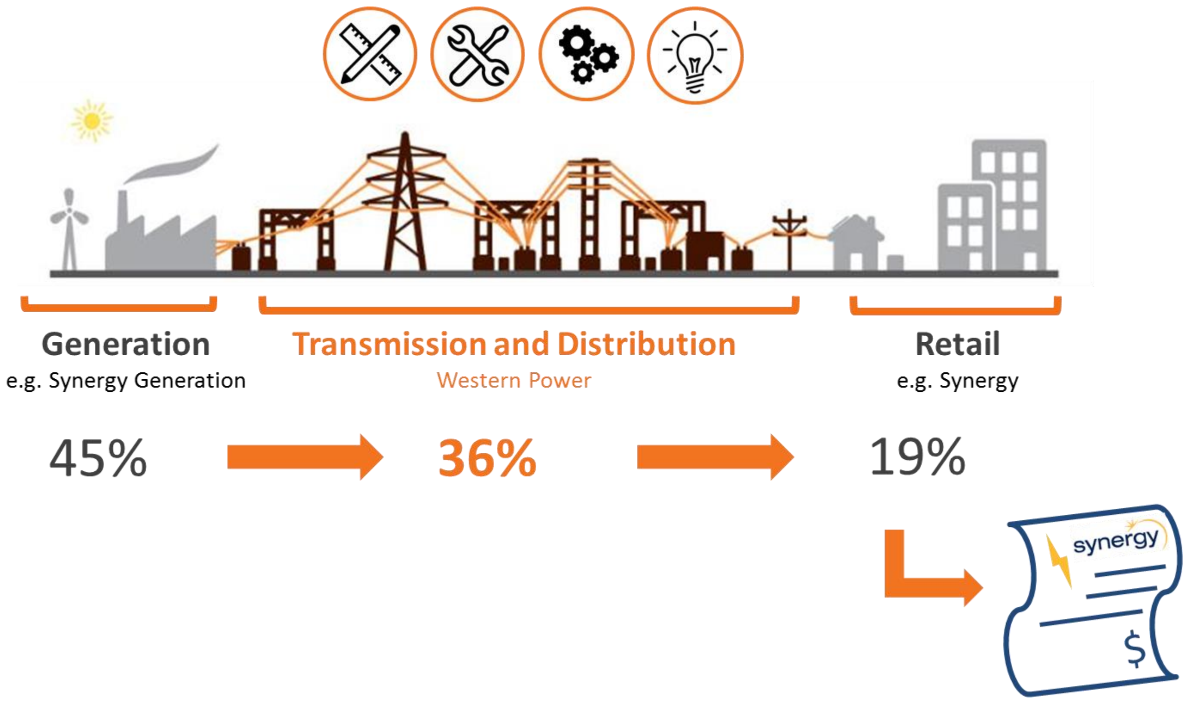
[20] 36 per cent excludes the tariff equalisation contribution (TEC), which is a cost collected by Western Power and then passed through to Horizon Power. The TEC is designed to help keep prices for regional electricity customers in line with customers served by the Western Power Network, and is mandated by State Government.

Figure 2.1: Western Power's role in the electricity supply chain



47. When customers use or connect to the Western Power Network, they expect the electricity to be there when they need it and for it to be delivered safely. They also expect the electricity to be affordable. That is why we at Western Power are continually looking for ways of operating our business more efficiently and, where appropriate, applying new technology – to keep our costs low so customers may benefit from lower electricity bills from their retailer.

48. While Western Power's network is mostly used to transmit electricity generated from traditional central energy sources (such as coal or gas power stations), this is changing, with more electricity coming from distributed renewable power sources such as wind and solar. The cost of these renewable technologies is declining and customers expect to be able to benefit from them, particularly given the emergence of battery storage and alternative energy solutions. Part of our role is to make sure we manage our network so customers can connect to new technology if they choose to.

49. Rather than assume conventional network management (i.e. more poles and wires) is always the answer, Western Power considers options for non-network solutions, such as managing demand (electricity usage) or structuring tariffs in a way that optimises the use of our network. However, where poles and wires are the most appropriate solution, we look at the best method and the most prudent time to install or replace them. We are always asking ourselves key questions such as: *Is it the right cost? Who will benefit? Do the assets need replacing? What's the risk of this technology becoming obsolete?*

50. Put simply, we are responsible for ensuring the network we build today meets the energy needs of Western Australians tomorrow.

2.1.1 Our network

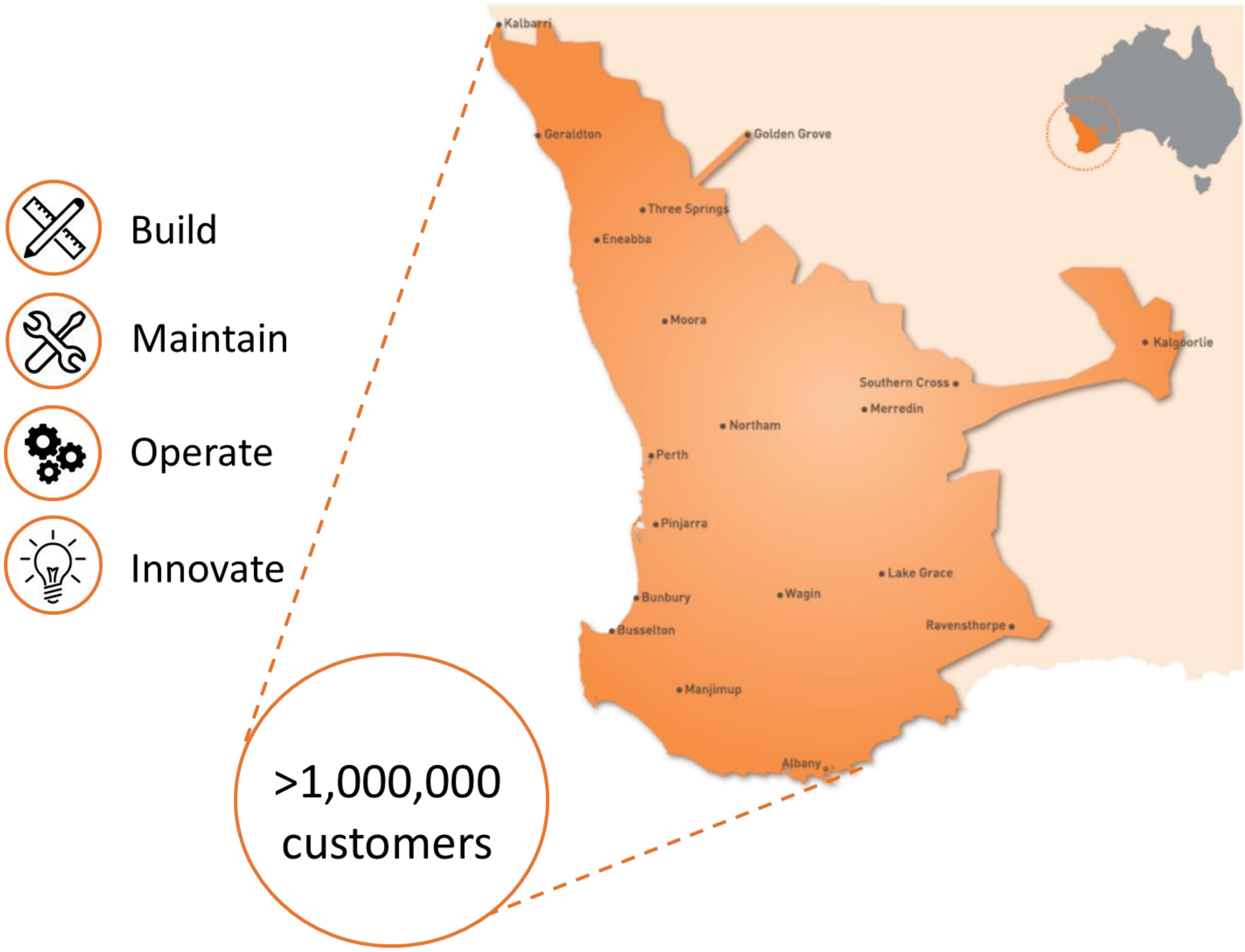
51. The Western Power Network is the largest electricity network in Western Australia. It forms the vast majority of the South West Interconnected Network (**SWIN**), which together with the electricity generators, comprises the South West Interconnected System (**SWIS**). The Western Power Network reaches as far north as Kalbarri, east to Kalgoorlie and south to Albany (see Figure 2.2). It is one of the world's largest

isolated networks, and unlike many other networks in Australia, consists of both a transmission and distribution system.

52. The vast majority of Western Power's 1.1 million customers are located in the Perth metropolitan area, and the network manages a load that ranges from 1,200 MW overnight to more than 4,000 MW on the hottest summer day.

53. We build, maintain and operate the network, transporting electricity safely, reliably and efficiently. We also invest in innovation. Western Power constantly looks at new and different ways of using the network and to understand how new technologies, such as battery storage and electric vehicles, may affect the network or provide opportunity to our customers.

Figure 2.2: What we do and the area covered by the Western Power Network



2.1.2 Our vision

54. Western Power's vision:

> *We deliver on the changing energy needs of Western Australians, powered by community trust and the passion of our people.*

55. At Western Power, we understand the energy sector is changing. Customers' expectations around service, prices and the use of technology are evolving, and will have a huge influence on the way electricity is

delivered in our state. While a network business' primary role is to connect people with electricity, we can no longer take it for granted that the traditional model of moving electricity from large base load power stations to a dispersed population will remain the dominant way of supplying electricity.

56. Breakthroughs in new technology, distributed storage, and standalone power systems over the AA3 period indicate that the role of the electricity network may look very different in the future. That's why our aim is for Western Australians to continue to trust us to meet their changing energy needs, whatever these needs may be.

57. We are therefore framing the future of our business around the following three themes:

1. maximise the value of today's business
2. enhance the value proposition of our network
3. reshape our business.

1. Maximise the value of today's business

58. Our business model over the last 50 years has been centred on building a network to transmit electricity that is generated centrally at large power stations, and distribute it to customers across the Western Power Network. As technology changes, this traditional network model may not be the most efficient or prudent over the long term. We must therefore keep the cost of managing the network efficient and invest prudently so the network can complement new non-grid electricity services such as solar and battery storage systems. We want to ensure customers continue to see and understand the benefits of remaining connected to our network (particularly when large usage appliances such as electric vehicles are drawing nearer) by:

- improving business performance and maintaining reliability
- improving the customer experience.

2. Enhancing the value proposition of our business

59. Western Power must evolve and keep pace with changes to customer preferences and advancements in technology to ensure the network remains relevant and efficient well into the future. We want to evolve our physical network and take a more 'modular' view, where we offer solutions based on the needs and economics of a local area. This might include changing the physical footprint of our network and providing alternative solutions to customers such as standalone power systems or micro grids. Our aim is to:

- provide incentive for customers to leverage the grid for their business models
- understand and shape end user perceptions and behaviour
- help our customers understand how the grid can benefit them.

3. Reshape the business

60. Now more than ever, new technologies are providing energy efficient appliances and new ways for people to self-generate and store electricity. This has already had an impact on network electricity volumes, which have been declining in recent years. Recognising this, we are looking at ways for Western Power to meet the energy needs of our customers today, tomorrow and into the future. Our aim is to:

- be innovative in the way we operate and manage the business
- identify ways to leverage our network, workforce and assets to efficiently deliver innovative solutions for customers.

61. Further information on how the Western Australian energy market is changing, and how it is shaping our forward plans, is provided in Chapter 3.

3. Changes in the energy market

62. This chapter provides an overview of recent changes in the Western Australian energy market, and how the changes have impacted Western Power and informed this proposal.

3.1 Technology, customers and reform: an ever-changing environment

63. Australia's electricity systems are changing. The way electricity is accessed is being transformed as customers embrace new technologies, take control of their energy use and move towards a sustainable future.

64. Across the country, mass take-up of rooftop solar generation is allowing customers to change the way they use the electricity grid. Industry experts foresee a future where, by the year 2050, customers will generate up to 45 per cent of all electricity in Australia[21], and advances in energy storage could offer customers an economic alternative to network connection. Network businesses across the country must move quickly to adapt and evolve.

65. Western Australia is no exception to this transformation. Analysis by CSIRO suggests Western Australia's rooftop solar capacity will triple by 2030 with customers adopting around 2,000 MWh of small-scale battery storage.[22]

66. Distributed generation, coupled with improved energy efficiency, have already made a significant impact on electricity usage volumes in the Western Power Network, with 29 per cent[23] of the load growth forecast at the beginning of the AA3 period failing to materialise and average energy consumption declining. Change is already upon us.

67. The Western Australian economy has also slowed dramatically since 2011. The Reserve Bank of Australia has observed that *Western Australia's business conditions have declined from above average, when mining investment and commodity prices were on the rise, to well below average of late.*[24] This economic decline has brought pressure on the electricity sector to improve productivity and reduce energy prices. Western Power has responded to the change in circumstances during the AA3 period and taken it into account in its plans for the AA4 period. The impact of the slowdown in growth and the economy is further discussed in section 3.1.1.

68. Emerging technology is an important consideration in our AA4 proposal. In the future, we expect the electricity grid will play a pivotal role in enabling customers to adopt new technologies such as peer to peer trading, micro grids, distributed generation and grid scale battery storage systems. This has changed our thinking around peak demand and the way customers might use the network in the future. The impact of technology is discussed in section 3.1.2.

69. Changing energy policy has also shaped Western Power's AA4 proposal. In March 2014, the State Government launched the Electricity Market Review (**EMR**), which sought to reduce the costs of electricity

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21 Page i, *Electricity Network Transformation Roadmap: Final Report*, Energy Networks Australia & CSIRO, April 2017.

22 Media release: *Western Australian solar set to triple – but national plan needed*, Energy Networks Australia, 28 April 2017.

23 Source AEMO: 29 per cent represents the difference between the forecast peak 2016/17 in the IMO's (now the AEMO) 2012 Electricity Statement of Opportunities (5,153 MW) and the actual 2016/17 peak reported in the AEMO's 2017 Electricity Statement of Opportunities (3,670 MW).

24 *Australia's Economic Transition* by Christopher Kent, Assistant Governor (Economic), Reserve Bank of Australia, 22 November 2016.

production and supply, and facilitate energy market long-term stability and investment in WA. The EMR recommended several reforms that significantly impacted Western Power's operations, including:

- transition to a fully constrained network model
- transfer of system management function to the Australian Energy Market Operator (**AEMO**)
- a move to the national economic regulatory framework
- introduction of contestability in retail and metering services
- removal of barriers to network connection.

70. While at the time of writing this proposal, only the transfer of Western Power's system management function to the AEMO has been implemented, the EMR has sharpened our focus on what the future may hold. We have incorporated some of the efficiencies and improvements identified during the EMR into this AA4 proposal. A summary of the EMR's impact on this proposal is provided in section 3.1.3.

71. In light of these challenges, Western Power has reviewed its investment plans, challenged its operating costs and has made transformational and sustained improvements to the way the network is managed. Our Business Transformation Program, which commenced in March 2016, has already achieved around $330 million in savings.[25] The Business Transformation Program is discussed in Chapter 5, Chapter 7 and below in section 3.1.4.

3.1.1 Changes in forecast growth and the Western Australian economy

72. Two of the most important drivers of Western Power's ongoing plans and investments are the forecast economic landscape and electricity demand growth. The slowdown in both demand growth and the Western Australian economy over recent years has had a dramatic impact on Western Power's activities and investment during the AA3 period.

73. The AA3 period expenditure forecast was developed during 2010/11, when the resources sector was buoyant and forecast energy demand growth remained strong. Western Power's forecast investment program for the AA3 period was scrutinised and, based on information available at that time, approved by the ERA as prudent and efficient for the coming years.

74. As the AA3 period progressed, it became clear that the landscape was changing. Forecast growth in electricity consumption began to decline. For the first two years of the AA3 period, Western Power delivered its forecast expenditure largely as approved in the further final decision of the access arrangement for the AA3 period. However, by 2014 the WA economy had begun to slow down, peak demand growth flattened and average annual consumption per connection declined (see Table 3.1 extracted from the *2014 Electricity Statement of Opportunities* by the Independent Market Operator (**IMO**)).

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25 At 30 June 2017.

Table 3.1: Electricity growth data, 2014 Electricity Statement of Opportunities, Independent Market Operator

Table 3.1: Key statistics for residential customers, 2008-09 to 2013-14

Year	Total number of connections	Growth in connections	Residential electricity sales (GWh)	Growth in sales	Average annual consumption per connection (kWh)	Growth in consumption per connection
2008-09	832,192	NA	5,102	NA	6,131	NA
2009-10	845,511	1.6%	5,349	4.8%	6,326	3.2%
2010-11	873,701	3.3%	5,403	1.0%	6,184	-2.2%
2011-12	893,750	2.3%	5,005	-7.4%	5,600	-9.4%
2012-13	899,356	0.6%	5,035	0.6%	5,598	0.0%
2013-14	909,680	1.1%	5,044	0.2%	5,545	-1.0%

Source: Synergy

75. There are several causes of the decline in growth, with retail electricity prices and new technology being major factors. The IMO commented in its *2014 Electricity Statement of Opportunities* that:

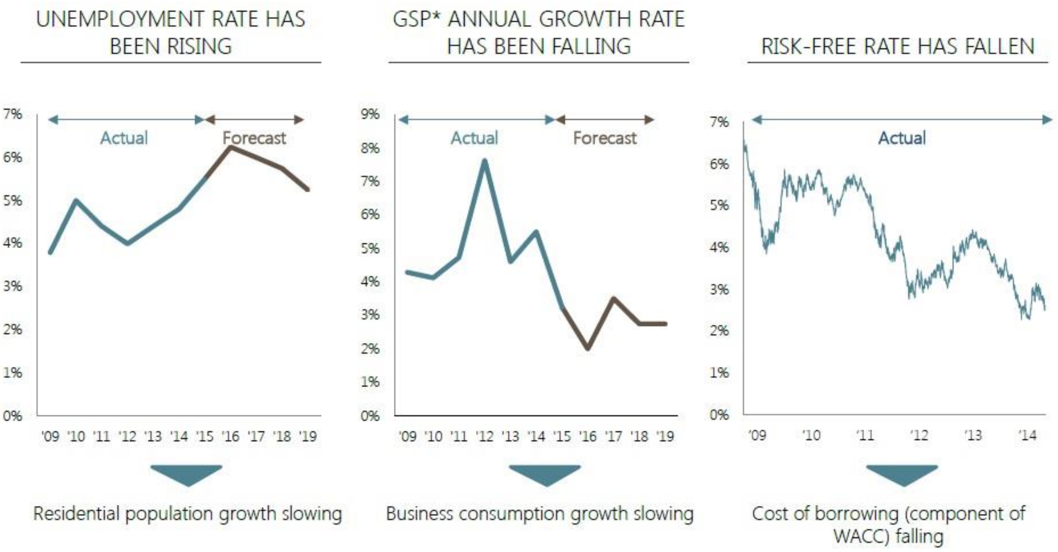
> *The IMO considers that while recent electricity price increases have contributed to the reduced average consumption per connection, a significant portion of the reduction is due to customers taking action such as:*
>
> - *Installing a solar PV system…*
> - *Installing more energy efficient appliances…*
> - *Changing consumption behaviour…*[26]

76. Put simply, customers have been taking control of their energy costs and using less electricity. As a result, Western Power has factored this change in customer behaviour and growth patterns into its investment plans.

77. The completion of several major resources projects also led to changes in prevailing economic conditions in WA. As part of its annual business planning process Western Power considered the impact of the changing economy on customers, prices and investment. Figure 3.1 shows some of our economic insights from 2014/15.

26 Page 26, *2014 Electricity Statement of Opportunities*, IMO.

Figure 3.1: Western Power's economic insights, 2015



*GSP = Gross State Product
Source: Forecasts from WA State Budget; U/E and GSP actuals from ABS; risk-free rate from Bloomberg.

78. It was apparent the economic assumptions that informed the proposal for the AA3 period in 2011 were no longer accurate and that significant changes to Western Power's expenditure program were required.

79. The Parliamentary Inquiry into Western Power's management of its rural wooden power poles[27], which concluded in 2012, also influenced Western Power's expenditure, particularly during the first half of the AA3 period. Following the Inquiry, Western Power commenced wide scale replacement and reinforcement of wooden distribution power poles, predominantly in rural areas. This meant that overall expenditure levels remained broadly consistent with the overall forecast for the first two years of the AA3 period, as the decrease in growth-related expenditure was offset by higher levels of distribution asset replacement. As the rural pole replacement program was completed, expenditure levels in the outer years of the AA3 period were significantly below forecast.

3.1.2 Impact of technology

80. Rooftop solar generation systems are perhaps the most prominent example of new technologies impacting network design, with more than 200,000 installed in the SWIS alone. Energy Networks Australia states in its *April 2017 Electricity Network Transformation Roadmap* that:

> *A future where up to 45% of all electricity is generated by customers in 2050 – at the opposite end of the system from its original design – presents a very significant range of technical, economic and regulatory challenges.*[28]

27 *Electricity Transmission and Distribution Management by Western power and Horizon Power*, Public Administration Committee, concluded 23/10/2012.

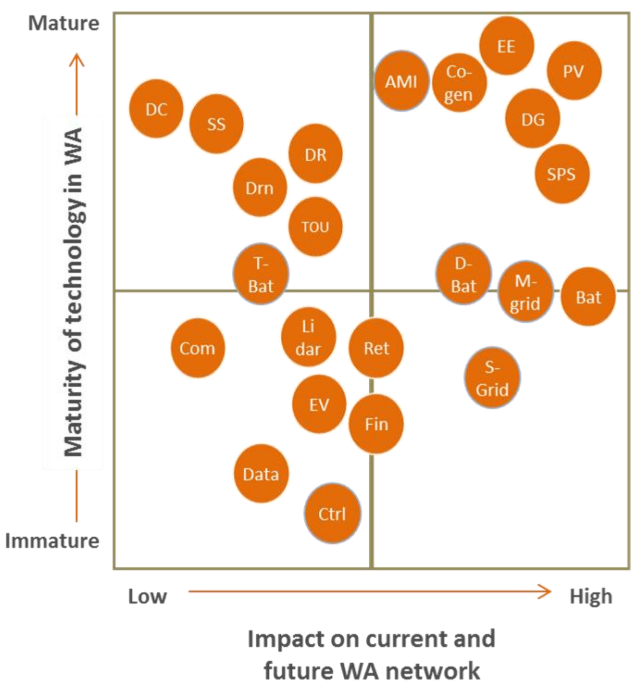
28 Page 1, *Electricity Network Transformation Roadmap: Final Report*, Energy Networks Australia & CSIRO, April 2017.

81. Solar penetration in Western Australia has already significantly impacted network peak demand, with the 671 MW of installed rooftop solar generating capacity[29] estimated to have reduced peak demand in 2017 by 265 MW or 7.2 per cent.[30]

82. Rooftop solar is also pushing the summer peak further into the evening. Peak demand for the 2016/17 summer was 3,670 MW, observed in the 17:00 to 17:30 trading interval on 1 March 2017. It was the lowest summer peak observed in the SWIS since 2009, and the first time since 2007 that peak demand occurred in March.[31]

83. However, rooftop solar is not the only technology that will shape the electricity network of the future. Battery storage (at an individual and grid-scaled level), standalone power systems, electric vehicles and micro grids are all emerging technologies that have the potential to significantly impact electricity demand and network design. Figure 3.2 summarises some of the technologies currently in operation or under development.

Figure 3.2: Overview of technology in the electricity sector



Key	Technology
PV	Rooftop PV (at the user)
Bat	Rooftop PV and storage
Ctrl	Rooftop PV, 'smart' storage and control
SPS	Standalone power supplies
EE	Energy efficiency, energy use
TOU	Energy efficiency, time of use
EV	Electric vehicles
AMI	Advanced metering infrastructure
DR	Aggregated demand response
S-Grid	Smart grids
Co-gen	Commercial co-generation
SS	Solar streetlights
DG	Utility-scale renewable generation
DBat	Storage in the distribution network
TBat	Storage in the transmission network
Data	Using 'big data' to reduce redundancy
M-grid	Microgrid systems
DC	DC transmission lines
Drn	Using drones to manage line inspections
Li dar	High resolution satellite photography
Com	Community generation models
Fin	Solar (and storage) financing models
Ret	Retail model innovation

84. Emerging technology has a significant influence on Western Power's plans for the AA4 period. The most immediate impact is that planned capex on capacity expansion is 72 per cent lower during the AA4 period than what was forecast for the AA3 period. This is predominately driven from the level of uptake of emerging technology, which has resulted in maximum demand flattening and average consumption per customer declining.

85. A secondary impact is the need to research, monitor and apply new technology. While it is clear Western Power's growth expenditure will be more conservative as technology changes customers' behaviours, it is

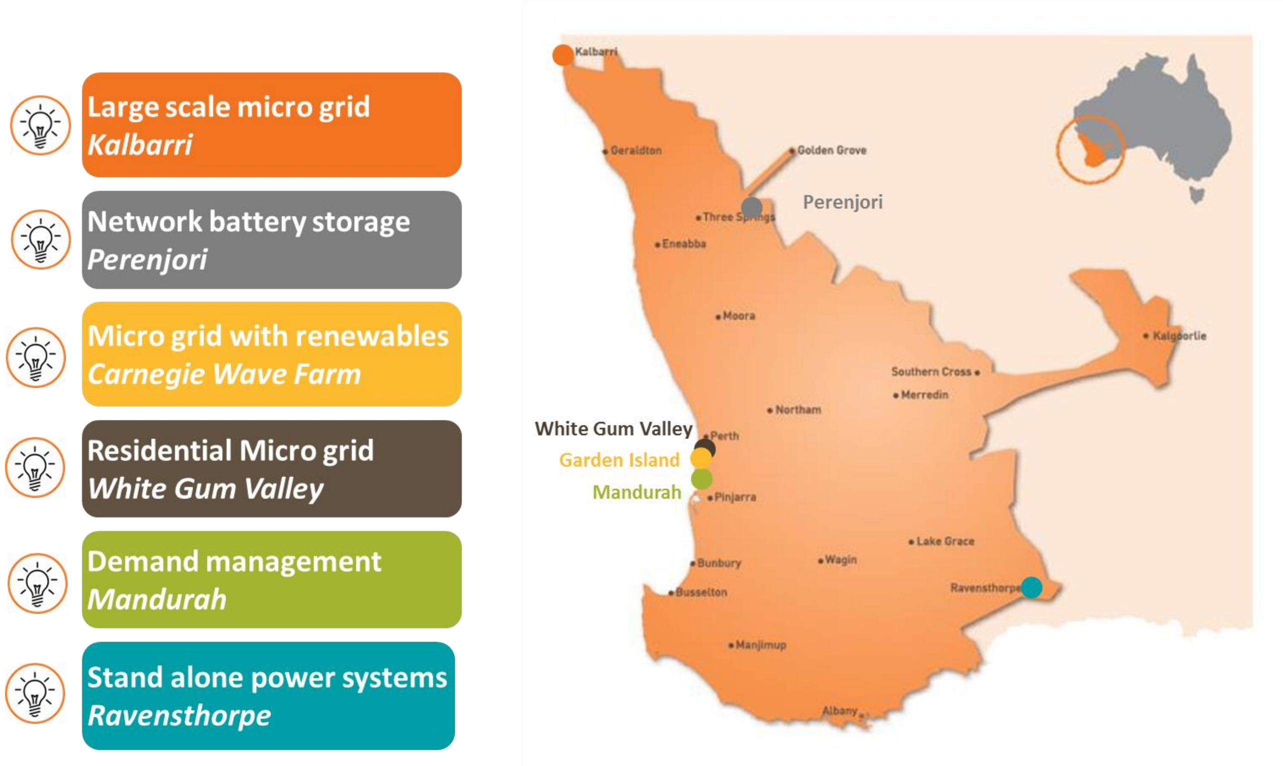
29 671 MW at February 2017. Source: *2017 Electricity Statement of Opportunities*, AEMO, June 2017.

30 *2017 Electricity Statement of Opportunities*, AEMO, June 2017.

31 Ibid.

important that we fully understand how technology will impact network assets and the energy solutions we offer in the future. During the AA3 period, Western Power commenced several technology trials, ranging from battery storage trials in Perenjori to testing standalone power systems in Ravensthorpe (see Figure 3.3).

Figure 3.3: Western Power's current non-network solution projects



86. The information resulting from these trials is extremely valuable; helping to inform the type of non-network solutions Western Power could offer to our customers. Energy Networks Australia considers that *Western Australia is set to lead the edge-of grid energy transformation in the coming decade and beyond as more customers continue to take up distributed energy resources like solar and batteries.*[32] Western Power concurs with this view, which is why we plan to continue trialling non-network solutions and other innovative technology over the AA4 period.

87. In accordance with section 6.40 and 6.41 of the Access Code, Western Power will investigate emerging technology as potential alternative solutions to network augmentation. This is also consistent with customer feedback received during our customer engagement program.[33] One of the key insights from customers engaged during the development of this AA4 proposal was:

> *Customers believe Western Power should use emerging technologies to deliver improved customer outcomes.*[34]

88. Subject to section 6.41, we will test whether investments in new technology *exceed the amount of non-capital costs that would be incurred by a service provider efficiently minimising costs*. Where a net benefit

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32 Page 1, *Electricity Network Transformation Roadmap: Final Report*, Energy Networks Australia & CSIRO, April 2017.

33 The customer engagement program is discussed in Chapter 4 of this AAI.

34 Customer insight #5, *Western Power customer insights feedback report*, Deloitte, August 2016.

to regulated tariff customers can be identified, the efficient and prudent costs associated with emerging technology will be recovered from regulated revenue.

89. The *Independent Review into the Future Security of the National Electricity Market* (led by Australia's Chief Scientist Dr Alan Finkel AO), outlines the importance of encouraging network businesses to pursue non-network solutions:

> *Network businesses should be rewarded for providing the services that consumers want. Currently, there are concerns that the regulatory framework favours capital investments, resulting in too much expenditure on network assets and too little expenditure on non-network alternatives.*
>
> *The regulatory framework should encourage network businesses to utilise new technologies where they are cheaper than building poles and wires. Such 'non-network' solutions could include purchasing services provided by DER [distributed energy resources] or utilising individual power systems or microgrids as alternatives to a traditional grid connection.*
>
> *The AER is currently developing a demand management incentive scheme to provide an additional incentive for demand-side projects, and an innovation allowance for research and development into non-network solutions that have the potential to reduce long-term network costs. Electricity networks are natural monopolies and are regulated accordingly. Even with advances in technology, it is unlikely to be economically efficient for a competitor to duplicate the assets needed to provide the service. Economic regulation is important for the uptake of demand-side resources because it shapes the incentives and obligations on networks to provide services to consumers.*[35]

3.1.3 The Electricity Market Review

90. The EMR examined the structure of the electricity generation, wholesale, and retail sectors within the SWIS. The review also examined the incentives for industry participants to make efficient investments and minimise costs.

91. During the first phase of the EMR (launched on 6 March 2014), the EMR Steering Committee[36] assessed the strengths and weaknesses of the WA electricity industry structure, market institutions and regulatory arrangements, and examined options for reform. Phase two, which was launched on 24 March 2015, saw the design and the implementation plan for electricity market reforms.

92. Phase two proposed four reform work streams[37]:

    1. **network regulation** – looked at transferring economic regulation of Western Power from the Western Australian regime to the National Electricity Law and Rules

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35 Page 150, *Independent Review into the Future Security of the National Electricity Market, Blueprint for the Future*, Dr Alan Finkel AO, Chief Scientist, Chair of the Expert Panel, June 2017.

36 A list of committee members is on the Department of Treasury website: https://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Electricity_Market_Review_-_Phase_1.aspx

37 Full details of the EMR can be found on the Department of Treasury website: https://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Electricity_Market_Review_-_Phase_2.aspx

2. **market competition** – looked at removing barriers to entry in the retail and wholesale markets. It also involved introducing full retail contestability for residential electricity customers, and contestable metering services
3. **institutional arrangements** – included transferring the system management and market operation functions from Western Power to the AEMO
4. **Wholesale Electricity Market improvements** – looked at reforming the energy capacity market and potentially introducing security-constrained dispatch.

93. Western Power recognised that elements of all four work streams would significantly impact operations for the AA4 period. Therefore, in agreement with the State Government, we commenced making structural and process changes to accommodate the proposed reforms. Of the proposed reforms that directly impacted Western Power, only the transfer of the system management function to the AEMO has been actioned at the time of drafting this AA4 proposal.

94. Since the change in State Government in March 2017, the EMR has, effectively, been on hold while the new Government considers how and when electricity market reforms should proceed. Therefore, Western Power's AA4 proposal considers only those reforms that have already been implemented at time of writing and does not explicitly provide for future reforms.

95. Should further certainty on key reform topics, such as full retail contestability or metering contestability, emerge during the course of the AA4 proposal review process, Western Power will modify its approach accordingly.

96. It is possible that the implementation of Government-led energy market reforms during the AA4 period would require amendments to the access arrangement to either facilitate the efficient execution of the reforms or respond to the effects of the reforms. To enable re-opening of the access arrangement during the AA4 period in the event of Government-led energy market reforms taking place, we propose a specific trigger event be included in the access arrangement. Detail of the proposed trigger event is provided in section 6.11 of this document.

97. Though the EMR was not implemented in full, the EMR activities have added value and set a sound platform for any future reforms. Indeed, the work Western Power conducted to support the reforms has helped shape the AA4 proposal. Several documents that were initially developed for submission to the Australian Energy Regulator (**AER**) under the National Electricity Rules have been repurposed for the AA4 proposal under the Access Code. Other reforms (such as the transfer of the system management function) have directly impacted our AA4 proposal. The legacy of the EMR work is discussed in the sections below.

98. Western Power is seeking to recover a portion of the costs associated with the EMR as an unforeseen event under section 6.6 of the Access Code. The EMR was announced by the State Government in 2014 and was not reasonably foreseeable during the development of the revisions for the AA3 period. As such, no provision for costs associated with the EMR were included in Western Power's AA3 period target revenue.

99. Our unforeseen event adjustment is discussed in Chapter 10 of this document.

3.1.3.1 Transfer of 'system management' to the AEMO

100. Western Power's system operations function transferred to the AEMO on 1 July 2016. The change means Western Power is no longer responsible for system security, including generator dispatch, procuring and dispatching ancillary services, and load and generation forecasting.

101. In terms of forward-looking costs, the transfer of the system operations function does not materially impact Western Power's forecast expenditure for the AA4 period. This is because the system operations function was a segregated entity, funded by its own allowable revenue process. However, the change does mean a number of corporate overheads such as building and fleet costs will no longer be allocated to system operations functions.

3.1.3.2 Transfer to the National Electricity Rules

102. One of the biggest recommended changes in the EMR for Western Power was the transfer of economic regulation to the AER under the National Electricity Rules. In preparation for the transfer, we developed extensive access arrangement revisions to comply with the new regulatory framework. However, the transfer to the national framework did not occur.

103. While this AA4 proposal has been developed in accordance with the Access Code, we have retained a number of the changes that were developed for the national framework, as we believe they satisfy the Access Code objective and, importantly, offer better outcomes for customers.

104. For example, the national framework requires network operators to provide a 30-year revenue offset when connecting residential customers. The purpose of the offset is to decrease the size of the customer's capital contribution. Western Power currently only offers a 15-year revenue offset to commercial customers. There is no offset for residential customers connecting to the Western Power Network. We see the benefit of providing a revenue offset to residential customers and note that it is something customers have asked us for in the past. Therefore, in this AA4 proposal, we propose to offer a 15-year offset for residential customers.

105. Other elements of the work conducted for the transfer to the national framework that are being retained for the AA4 proposal include:

- **major event day definitions** - modifying the definition of major event days. The major event day proposal is discussed in Chapter 6 of this document
- **advanced metering** - the National Electricity Rules provide that advanced meters are the default asset when replacing existing meters or installing a new meter. In most jurisdictions in the National Electricity Market, the residential electricity retail market is contestable. In November 2015, the Australian Energy Market Commission (**AEMC**) conducted a 'Power of Choice' review, resulting in a series of changes whereby metering services were also made contestable, with a view to supporting the efficient roll-out of advanced metering technology. The AEMC considers:

  > *Improved access to the services enabled by advanced meters will provide consumers with opportunities to better understand and take control of their electricity consumption and the costs associated with their usage decisions.*[38]

  Western Power does not consider that the introduction of full retail contestability (**FRC**) for residential customers is a prerequisite for advanced metering. The benefit to consumers arising from greater control of their electricity usage would equally apply in a non-contestable market. The enhanced capability enabled by advanced metering and associated infrastructure to efficiently manage the network would also promote better network investment and operation.

  We propose advanced meters be the default meter for the AA4 period (for both new and replacement meters). We expect to install approximately 355,000 over the next five years as out-

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[38] ERC0169 rule change overview, AEMC http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv#

dated mechanical meters reach the end of their useful lives, new connections are established and customers require replacement meters.

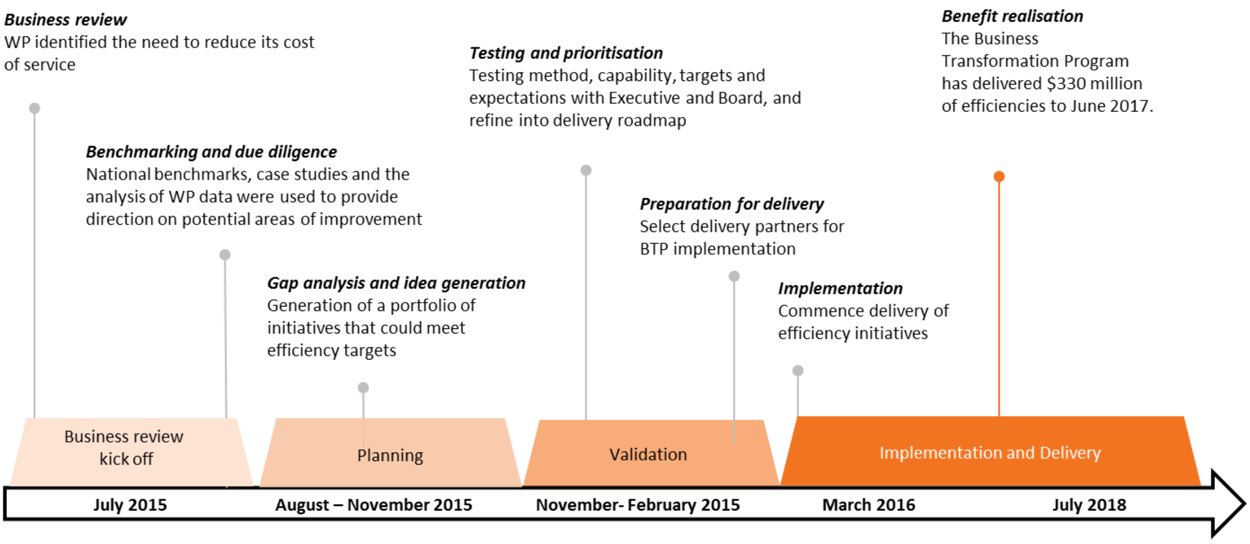
3.1.4 Western Power's business transformation

106. Western Power's response to changing customer expectations, market reform and slow economic growth, was to undertake an in-depth review of its business processes, operating costs, and business plans.

Figure 3.4: Factors driving Western Power's business review

107. We commenced a program of operating cost reviews at the beginning of the AA3 period, looking at our organisational model undergoing an internal restructure in 2012 and 2013. This ongoing business review continued, gathering pace in 2014 as economic conditions slowed and State Government-led reforms emerged. The review culminated in Western Power's Business Transformation Program, which commenced in 2015 (see Figure 3.5).

Figure 3.5: Business review and Business Transformation Program time line



108. The first step of the business review was to set targets for efficiency improvements. We did this by looking at our business processes and environment to identify potential efficiency areas. We also looked at other electricity network businesses and conducted high-level benchmarking to give us an indication of how Western Power's operating costs compares to other distribution network providers.

109. While Western Power's unique combined transmission and distribution structure and operating environment means it is difficult to benchmark our business against standalone distribution networks or transmission networks. The benchmarking exercise was nevertheless a useful tool to help set realistic expectations of where Western Power's costs of service could be improved.

110. Based on the assessment of our 2014/15 performance and using the AER's annual benchmarking reports as a guide, we estimated that Western Power's transmission network business operates at a level of efficiency and productivity comparable with our interstate counterparts. However, our distribution business compared less favourably with many of the more mature, privately owned distribution businesses in the National Electricity Market (see Figure 3.6).

Figure 3.6: 2014/15 distribution network service provider benchmarking assessment (pre Business Transformation Program)

MTFP assessment of Australian distribution network service providers

		DNSP	Average Rank	2014 Rank	Average Score	2014 Score	2014 % change
"Top Quartile"		CitiPower	1	1	1.711	1.555	-2.4%
		SA Power Networks	2	3	1.521	1.322	-4.3%
		United Energy	3	2	1.484	1.366	-2.5%
"Mid Table"		Jemena	4	4	1.382	1.302	-0.8%
		Powercor	5	6	1.280	1.173	-0.6%
	G	Energex	6	5	1.262	1.196	2.5%
		AusNet Services	7	8	1.234	1.093	-4.6%
	G	Endeavour Energy	8	7	1.223	1.135	-2.9%
	G	Ergon Energy	9	9	0.992	1.073	1.4%
"Bottom Quartile"	G	Ausgrid	10	11	0.986	0.926	-5.8%
	G	Essential Energy	11	10	0.977	0.928	8.5%
	G	ActewAGL	12	13	0.952	0.845	-6.0%
	G	TasNetworks	13	12	0.942	0.863	-3.8%

westernpower indicative pre-BTP position

**DNSP MTFP rankings for 2014 and period-average from the AER's 'Annual Benchmarking Report' for Electricity Distribution Network Service Providers (Nov 2015)

G = Government owned (in 2014)

111. Western Power used the insights from the benchmarking exercise to support a bottom-up build of ideas for potential efficiencies. These ideas were tested and validated with the Executive and Board and then refined into a delivery roadmap.

112. We began implementing the Business Transformation Program in March 2016, and will continue the program into 2018. Process improvements are being built into business as usual activities concurrently, and have resulted in an efficient baseline level of expenditure which we have used to develop forecast costs.

113. To 30 June 2017, the program has realised $330 million in recurring cost savings (see Table 3.2). The efficiencies (both realised and forecast) have been built into our operating expenditure forecast for the AA4 period. More detail of the efficiencies achieved via the program is provided in Chapters 7 and 8 of this document.

Table 3.2: Business Transformation Program recurring costs savings by work stream, $ million real at 30 June 2017

Work stream	Savings in recurrent costs realised at 30 June 2017
Asset management	151.9
Customer funded	12.1
External spend review	44.3
Field force central	19.8
Field force perform	30.5

Work stream	Savings in recurrent costs realised at 30 June 2017
ICT	11.8
Organisational model	35.6
Shared services	23.8
Total	**329.7**

114. The Business Transformation Program has enabled us to rationalise our operating costs to a point where we expect to be able to maintain current service levels in a more cost effective way during the AA4 period. We have reduced our capital expenditure during the AA3 period, and enter the AA4 period with an investment program that better reflects the future growth of the business and changes in customer expectations.

4. Customers, stakeholders and community engagement

115. This chapter provides an overview of the stakeholder engagement Western Power has recently conducted and how it has informed the AA4 proposal.

4.1 Our approach to stakeholder engagement

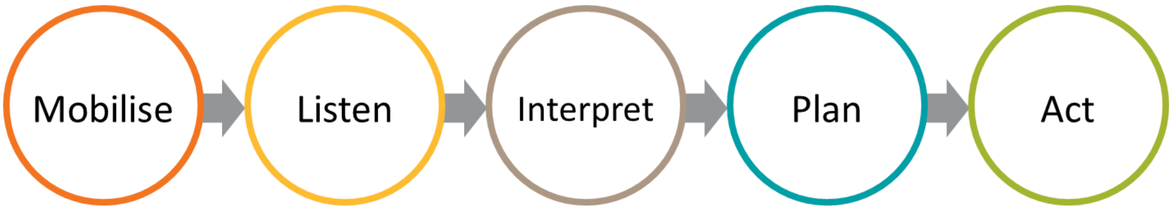
116. At Western Power we are mindful of the impact our actions have on our customers' electricity bills. Our aim is to ensure customers are getting value for money – paying for services they will benefit from in the short and long term. That's why in 2015, as part of our ongoing commitment to being a customer-focused organisation, we commenced our engagement program. We met with a number of stakeholders including residential and business customers, community groups, customer advocates, retailers and generators to understand what they expect from their electricity network, and what they believe Western Power should be investing in. The customer engagement program has not only informed this AA4 proposal, but will also shape our ongoing customer engagement throughout the AA4 period and beyond.

117. Western Power's customer engagement program was designed to:

- obtain customer and stakeholder input into our proposed expenditure strategy and plan
- be far reaching and represent all customer groups
- establish an ongoing conversation with customers – providing feedback on how their participation has helped influence the AA4 proposal.
- obtain customer insights to integrate into our business decision-making processes
- measure the success of engagement through methods including direct feedback and advocacy.

118. Development of the customer engagement program consisted of five phases (see Figure 4.1):

Figure 4.1: Customer engagement program development phases



4.1.1 Mobilise phase

119. To best understand how investment options are going to affect a particular type of customer we needed to engage a diverse range of customers on a variety of subjects. Figure 4.2 shows our customer groups. The first phase involved identifying customer groups.

Figure 4.2: Western Power customer groups

4.1.2 Listen phase

120. Commencing in September 2015, the Listen phase involved meeting and talking with a variety of customers to hear their views and understand what they do and do not expect from their network provider. The objectives of this stage were to:

- enable customers to input into Western Power's proposed expenditure strategy and forward plan
- provide a forum for all customers, including underrepresented groups, to have a voice
- understand how customers respond to the idea of trade-offs when making choices around scenarios presented to them
- provide opportunities for customers to express their own priorities.

121. We engaged Deloitte to assist with the delivery of the customer engagement program. Deloitte has facilitated customer engagement programs for a number of Australian energy network businesses, including Australian Gas Networks and SA Power Networks. Deloitte's role was to:

- ensure the customer engagement program was conducted in an independent and robust manner
- ensure the findings of the customer engagement program were an accurate reflection of Western Power's customers preferences
- develop and facilitate workshops with support from Western Power subject matter experts
- design a phone survey to understand customers' willingness to pay for reliability and safety improvements and the trade-offs they are willing to make
- recruit a representative sample of Western Power's customers for the workshops and phone survey.

122. To ensure feedback was collected in a coordinated and consistent format, five research themes were used to inform the structure of the workshops, phone survey and interviews. The research themes were aligned to Western Power's strategic objectives, orientation and purpose. The themes are presented in Table 4.1.

Table 4.1: Customer engagement program research themes

Research theme	Description
Customer experience	Customer service, channels and opportunities
The future network	New technologies and Western Power's role in the future electricity network
Network safety	Western Power's safety strategies
Network reliability	The reliability of the Western Power Network
Access and affordability	Electricity price tariff structure

123. Each customer group required different methods of engagement to explore the five research themes. The mixture of quantitative and qualitative engagement methods used is described below.

- **Customer workshops** – workshops were used to explore the opinions and preferences of residential and small and medium enterprise (**SME**) customers. The workshops also provided a forum for presenting and gauging customer reactions to the various investment options Western Power may consider. This approach enabled a detailed understanding of what underpinned the customers' responses and helped frame and contextualise the quantitative survey results.
- **Telephone survey** – a phone survey was implemented to capture a statistically representative view of Western Power's residential and SME customers. This means the survey results could be extrapolated to better understand the opinions and preferences of a broad sample of Western Power's customer base.
- **Targeted customer interviews** – one-on-one interviews were conducted with other customer segments, for example large commercial customers. These interviews allowed for in-depth exploration of the research themes.
- **Customer reference group** – this was formed to provide peak bodies and other stakeholder groups with the opportunity to provide input to Western Power on the research objectives and approach used in the customer engagement program.
- **Online survey** – a survey available on the Western Power corporate website provided the opportunity for customers not directly recruited in the engagement program to provide their input.

124. Table 4.2 presents a summary of the engagement methods used for each customer group.

Table 4.2: Customer engagement methods

Customer group	Engagement method				
	Customer workshop	Telephone survey	Customer interviews	Customer reference group	Online survey
Residents	x	x			x
Small and medium businesses	x	x			x
Large businesses and Government			x		x

Customer group	Engagement method				
	Customer workshop	Telephone survey	Customer interviews	Customer reference group	Online survey
Local government			x		x
Land developers			x		x
Electricians and service providers			x		x
Electrical consultants			x		x
Generators			x		x
Retailers			x		x
Peak bodies				x	x

125. The following sections describe the engagement methods we used in more detail.

4.1.2.1 Customer workshops

126. During the listen phase, nine customer workshops were held; six with residential customers and three with SMEs.[39] Workshops were hosted across the network to ensure the voices of metropolitan and regional customers were heard (see Figure 4.3).

39 A further 5 workshops were held during the plan phase of the program.

Figure 4.3: Locations of residential and SME customer workshops

127. The workshop structure was consistent throughout all sessions and aligned to the specific research themes. Table 4.3 summarises the discussions and exercises used to capture customer views.

Table 4.3: Workshop structure and content

Section/research theme	Content	Activity
A. Introduction	• Western Power's history • Role in the electricity supply chain • Contribution to electricity prices	n/a
B. Customer experience	• Customer service • Communication channels and preferences	• Discussion: What is good customer experience to you? • Worksheet: communication channel preferences

Section/research theme	Content	Activity
C. The future network	• Traditional network structure • The changing structure of the modern network • New technologies	• Discussion: Do you use new technologies? • Discussion: What are your thoughts on new technologies? • Discussion: How do you see Western Power operating in the future?
D. Access and affordability	• Explanation of tariff structures • Introduction of time of use tariff structures • Metering	• Activity: Which tariff structure do you like? • Worksheet: What tariff structure should Western Power investigate? • Worksheet: Which meter would you prefer to install?
E. Network reliability	• Customer reliability expectations • Current reliability performance and network issues • Process to deliver a reliable network • Potential projects to deliver a reliable network	• Discussion: Who has experienced an outage? • Activity: Should Western Power focus its efforts on reducing the frequency or duration of outages? • Worksheet: Reliability investment options
F. Network safety	• Current commitment to safety • Current safety programs • Potential bushfire management programs	• Discussion: Western Power's safety record • Worksheet: How should Western Power address bushfire safety?

128. Residential workshop participants were recruited to provide a diverse sample group based on age, household income, property ownership, and geography. SME participants were recruited based on industry, number of employees, revenue and geography. SME workshop participants were made up of either the decision makers or those involved in decisions relating to the enterprise's electricity supply. Each workshop had at least one attendee (but no more than three) with a solar photovoltaic installation.[40] Structuring the workshops in this way allowed for a diverse sample that best represented Western Power's customer base and would provide reliable feedback.

4.1.2.2 Telephone survey

129. The phone survey was conducted in November 2015 and was completed by 3,500 customers (2,500 residential and 1,000 SMEs). For planning and operational purposes, Western Power divides the network into 15 load areas. Quotas were set to gather a sufficient sample within each load area to allow results to inform Western Power's future investment decision making process. The survey sample represented regional and metropolitan customers, and was designed to determine customers' willingness to pay for

40 This is consistent with the solar PV penetration rate of 20 per cent in the SWIS.

Western Power services and the trade-offs they are prepared to make between cost and service performance. Table 4.4 shows the regional/metropolitan split of the phone survey sample.

Table 4.4: Telephone survey sample

Location	Residential customers	SME customers	Total
Metropolitan	1,600	643	**2,243**
Regional	900	357	**1,257**
Total	**2,500**	**1,000**	**3,500**

130. The 20-minute telephone survey consisted of nine sections. Table 4.5 below maps the telephone survey sections and how they aligned to the workshops conducted and the research themes. It is important to note all survey respondents were provided with the same level of information on Western Power's role to ensure answers were comparable across the entire sample.

Table 4.5: Telephone survey sections

Section	Purpose	Link to workshops
1. Screening / classification	• Identification of the household/SME decision maker around electricity choices • High level demographics/firmographics • Capture intentions to take on any new electricity related technology and current energy mix used	• Linked to similar geographic regions
2. Knowledge and awareness	• Current knowledge of Western Power and the electricity industry • Inform survey respondents of relevant information to ensure the survey sample was similarly educated	• Introduction and awareness discussion (section A)
3. Segmentation and attitudinal questions	• Attitudes towards power interruptions and other service expectations • Attitudes towards time of use tariffs	• Reliability discussions (section E) • Tariff structure activity (section D)
4. Customer needs and preferences	• Communication preferences	• Customer experience discussion and communication channels worksheet (section B)
5. Network reliability	• Experience and attitudes towards network reliability	• Reliability exercise (section E)
6. Choice task	• Understand the trade-offs customer are willing to make with regards to price and reliability preferences (see 'assessing willingness to pay' below)	• n/a

Section	Purpose	Link to workshops
7. Additional services and the future of the network	• Regional reliability • Solar and battery intentions • Future customer service exercises	• Customer experience discussion (section B) • Future network discussion (section C) • Reliability investment options worksheet (section F)
8. Demographics	• Additional demographics	• n/a
9. Firmographics	• Additional firmographics	• n/a

4.1.2.2.1 Assessing willingness to pay

131. It is important for Western Power to understand its customers' willingness to pay for network security and reliability and the trade-offs they are willing to make for potential investments in the network. In particular, during the customer engagement program we sought to understand our customers' willingness to pay for improvements in the reliability of their electricity supply. Section six of the phone survey measured customers' willingness to pay though a choice model.[41]

132. Choice modelling works by presenting customers with a series of scenarios. Each scenario presents the customer with two options to choose between. These options require the customer to make a trade-off between them. The options presented during the customer engagement program were based on:

- duration of outages
- frequency of outages
- the time of day outages occur
- impact on annual electricity bill.

133. By asking respondents to make choices between similar situations, customer preferences could be ascertained.

134. Each respondent was presented with ten two-choice scenarios and asked to choose one of the two options. These scenarios were developed so each respondent was allocated a completely different set of scenarios, allowing a large number of combinations to be tested. This method allowed us to statistically analyse how outage duration, frequency, time and related cost informs the trade-offs customers are willing to make.

135. While the choice model provides the best indication of our customers' willingness to pay for reliability, safety and bushfire mitigation, during the workshops and surveys we also sought to understand the customers' preferences regarding price. For some questions in the workshop and surveys, customers were provided with an indicative bill impact to help inform their decisions. These bill impacts were based on the average bill and cost of an investment option.

41 Choice modelling is the industry standard approach to assessing the trade-offs customers are willing to make, and is widely used in research to quantify customers' preferences and willingness to pay.

136. For example, a respondent was asked to choose between these two scenarios:

1. power outages 2-3 times per annum, in the afternoon, and lasting less than an hour, with a $25 increase to your annual bill
2. power outages 2-3 times per annum, in the morning, and lasting three to six hours, with a $50 reduction to your annual bill.

4.1.2.3 Customer interviews

137. During November and December 2015, we conducted 35 interviews with customers from large business and stakeholder groups. The interviews lasted 45 minutes and were structured according to the workshop research themes. Questions were tailored to the particular customer group. For example, an interview with a land developer included more questions relating to the future network and Western Power's role in new land developments. Table 4.6 summarises the number of interviews for each of Western Power's customer groups.

Table 4.6: Customer interviews November/December 2015

Customer group	Number of interviews
Local government	9
Electrical consultants, electricians and service providers	7
Land developers	3
Large businesses and Government	10
Retailers and generators	6
Total	**35**

4.1.2.4 Customer reference groups

138. Two workshops with customer reference groups were held in December 2015. One of these was with members of the Strategic Reference Group, an existing group established by Western Power, comprising representatives of the Western Australian property development and construction industry.

139. The other workshop involved members of our customer reference group. The customer reference group was established to provide an avenue to identify issues and test the approach and findings of the customer engagement program. Customer reference group members include:

- Chamber of Commerce and Industry of Western Australia
- Financial Counsellors Association of Western Australia
- St Vincent de Paul Society
- Western Australian Local Government Association
- Western Australian Farmers Federation
- Western Australian Council of Social Service (**WACOSS**).

4.1.2.5 *Online survey*

140. An online survey was accessible on the Western Power website. Advertised through a hyperlink on the website, the survey was also promoted internally to encourage employees' friends and family to participate. Participants in the customer reference groups were also given a link to the website to share with their members.

4.1.3 Interpret phase

141. During the interpret phase, Western Power analysed the information obtained during the various workshops, interviews and surveys, and used these to develop customer insights. The 15 customer insights that were obtained are summarised in Table 4.7.

Table 4.7: Summary of customer insights

Research theme	#	Insight	Comment
Overarching insights	1	Customers are sensitive to price increases	Price is the dominant factor considered by customers when making choices relating to their energy use.
	2	Customers are aware of Western Power but are unclear about the role it plays in the energy industry	Customers demonstrated a lack of understanding of Western Power's role. While 95 per cent of residential customers knew who Western Power was, only 10 per cent could identify Western Power's contribution to their electricity bill.
Customer experience	3	Customers want to interact with Western Power through multiple channels	In the workshops, customers looked for a choice of mediums through which they can obtain information and interact with Western Power.
	4	Local staff as well as accurate and timely support is essential for a positive customer experience	Customers expect Western Power to know enough about them to be able to manage their enquiry efficiently. Workshop participants shared their frustrations with other service provides who have offshore call centres.
The future network	5	Customers believe Western Power should use emerging technologies to deliver improved customer outcomes	Workshop attendees wanted to discuss the impact technologies like batteries, electric vehicles and other new technologies will have on the network. If it is cheaper to use new technologies to supply electricity

Research theme	#	Insight	Comment
	6	Customers want Western Power to play a role in the supply of electricity into the future	at the same or better level of reliability then customers support Western Power using those technologies.
Access and affordability	7	Customers who have been educated about electricity tariffs are more likely to support a time of use tariff	Customers who participated in workshops that discussed tariff reform supported time of use tariffs. Customers that participated in the telephone survey, which did not provide detailed education on time of use tariffs, were unclear of the benefits. Customers who felt they would not be able to adjust their usage patterns did not support time of use tariffs.
	8	Customers who believe they are unable to alter their usage pattern do not support the implementation of a time of use tariff	
	9	Customers who favour a time of use tariff are willing to pay for technology that allows them to monitor their usage	Customers who supported time of use tariffs were asked whether they preferred digital meters or wanted Western Power to invest in upgrading every meter to an advanced meter. When the difference between the digital meter and advanced meter were explained, most participants were in favour of paying Western Power to install advanced meters across the network.
Network reliability	10	Customers are accepting of occasional outages	Although customers would prefer no outages, they accept it is reasonable for a small number of planned and unplanned outages to occur.
	11	Accurate and frequent communication is essential during supply interruptions	Customers accept some outages, but value accurate and frequent information.
	12	Longer outages are more disruptive to customers than frequent (short) outages	The quantitative survey revealed that the length of outages was more important to customers than the frequency of outages. Workshop participants also remarked that long outages cause them more inconvenience.
	13	A reliable source of electricity is essential for all customers, and customers are willing to spend money to ensure all people on the network have a reliable source of electricity	Customers are generally happy with their own reliability and are willing to fund the improvement of areas that have below-average reliability scores.

Research theme	#	Insight	Comment
Network safety	14	Customers want Western Power to continue to improve network safety, although are divided on whether they should pay for it	Western Power's focus on safety was widely recognised by customers. Survey respondents supported an increase in safety spending but were undecided on whether they should pay for these improvements. Workshop participants agreed bushfire safety expenditure could be more efficiently targeted in high-risk regions.
	15	Customers want to see bushfire safety investment targeted in areas where it has the greatest impact	

142. Details of how customer insights were measured and interpreted are provided in the Deloitte reports provided at Attachment 4.1. An example of how customer insights were captured and interpreted is provided below.

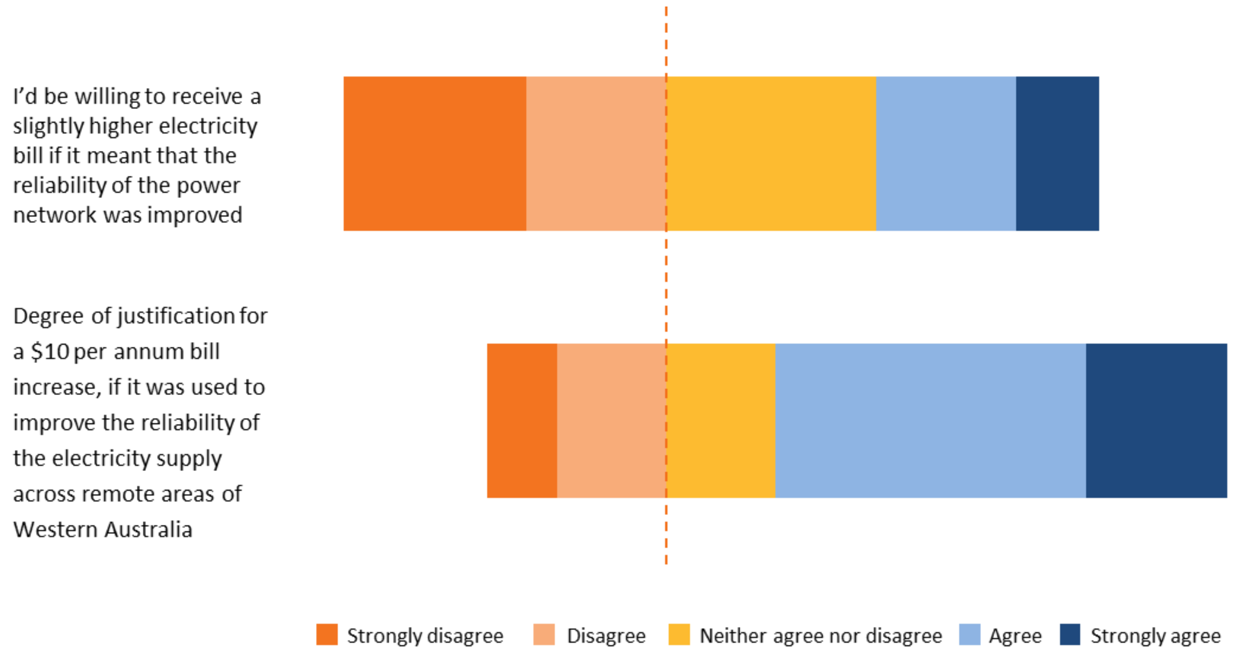
4.1.3.1 Customer insight – example

> *Customer insight #13 – A reliable source of electricity is essential for all customers, and customers are willing to spend money to ensure that all people on the network have a reliable source of electricity.*

143. Western Power found that customers consider a reliable supply of electricity is important and they believe everyone connected to the network, regardless of their location, should experience an acceptable level of reliability. The majority of customers (61 per cent) felt an increase in their annual bill of $10 was justified to improve the reliability of the electricity supply across remote areas of the Western Power Network. There was no significant difference between regional and metropolitan responses for residents or SMEs.

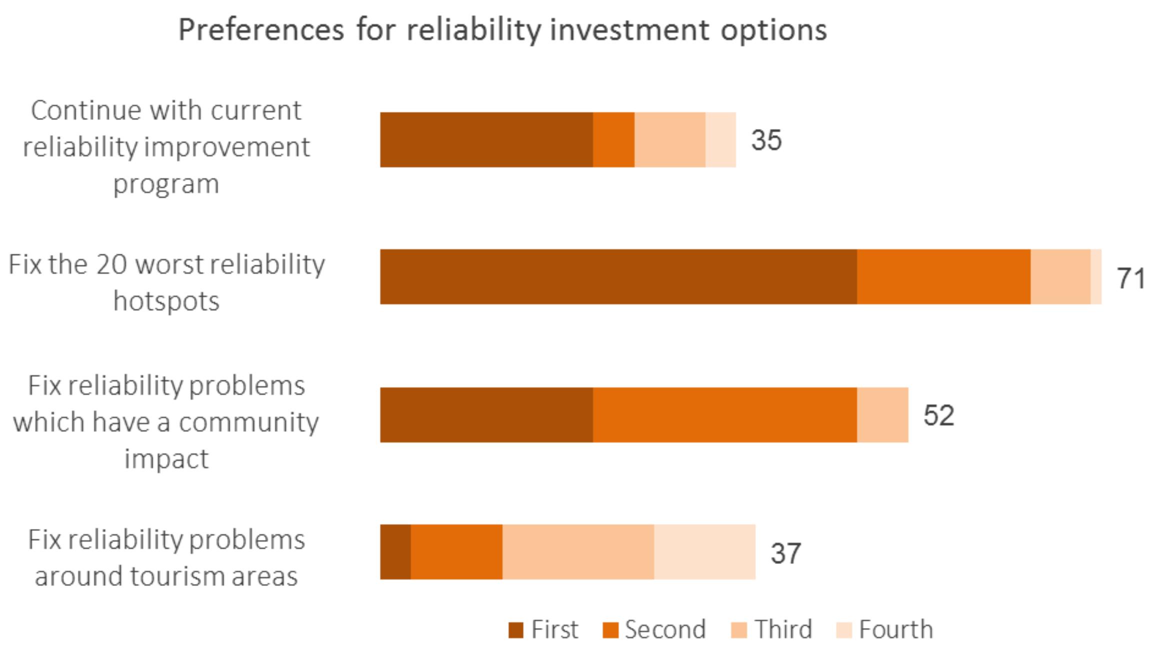
144. However, only 28 per cent of customers supported an increase to their electricity bill to improve reliability across the whole network. This suggests customers are largely satisfied with the current level of service they receive and aren't prepared to pay for service improvements above this.

Figure 4.4: Customer insights on reliability



145. The workshops allowed Western Power to explore options for addressing reliability issues across the network. The costs associated with these options were also outlined to customers, who were then asked to share their preferences for how Western Power could address reliability issues. These options, and the results are presented in Figure 4.5

Figure 4.5: Customer preferences on options to address reliability issues



146. The majority of workshop participants indicated a preference for Western Power to target the top 20 reliability hotspots in the network (in addition to the current reliability investment program). Participants

were presented with the estimated cost impact associated with this investment, to understand their willingness to pay.

147. The full Deloitte report containing all customer insights and interpretation is provided in Attachment 4.1.

4.1.4 Plan phase

148. During the plan phase, Western Power analysed the customer insights acquired through the listen phase, and began building them into investment plants for the AA4 period. Customer feedback was one of many factors incorporated into the business as usual planning processes. We looked at opportunities to address issues raised by customers, remaining mindful of our responsibility to ensure investment is prudent and efficient.

149. A key part of our customer engagement program was to test the findings from the interpret phase with customers and share an outline of our plans before including them in the AA4 proposal. Once again working with Deloitte, we arranged a series of workshops with customers during May and June 2016, where we shared a high-level overview of how their insights were shaping our plans.

150. A total of 60 people drawn from attendees of the Listen phase workshops attended the plan phase workshops. Deloitte facilitated the discussions, with Western Power representatives sharing the proposed investment plan with the participants. Table 4.8 presents the topics discussed at the workshops.

Table 4.8: Summary of plan phase workshop topics

Section / research theme	Western Power's proposed business plans
Introduction	n/a
Customer engagement program	n/a
Overarching insights	• Business transformation • Safety and awareness campaigns
Customer experience	• Expanding use of digital channels • Enhancing call centre capabilities • Implementing a customer management system
Future of the electricity network	• Perenjori low voltage network reinforcement • White Gum Valley residential microgrid project • Kalbarri microgrid feasibility study • Mandurah demand management
Access and affordability	• Tariff structure • Advanced metering infrastructure
Network reliability	• Support and improvement of planned outage notification • Upgrade of the call centre and social media platforms to support communication • Fixing reliability hotspots

Section / research theme	Western Power's proposed business plans
Network safety	• Proposed five-year inspection cycle • Implementation of consequence approach to fire prevention

151. A copy of Deloitte's customer insights report from this phase is provided in Attachment 4.1.

152. The plan phase also included a specific workshop on time of use tariffs. This workshop sought to present customers with the options available for time of use tariffs, and gauge their appetite for adopting tariff reforms.

153. The plan phase of the customer engagement program concluded in June 2016. Workshop participants found that the feedback process was rewarding and were impressed by Western Power's response to their preferences. The next step was to incorporate the customer insights in the AA4 proposal.

4.1.5 Act phase

154. The act phase of the customer engagement program is where Western Power built feedback from customers into the expenditure and service level within the AA4 proposal. Table 4.9 summarises how we have incorporated customer insights into our plans for the AA4 period.[42]

Table 4.9: Summary of how customer insights have been incorporated in the initial AA4 proposal

#	Insight	How we have incorporated this in our AA4 proposal
1	Customer are sensitive to price increases	The price impact on customers, particularly residential and small businesses, has been considered when developing all proposed revisions. All expenditure forecasts have been subject to top-down review and assessment to ensure they represent a network business efficiently minimising costs. Western Power's WACC proposal, which typically has the greatest impact on revenue (and therefore prices), has been tested and moderated to reduce the impact on customers where possible.
2	Customers are aware of Western Power but are unclear about the role it plays in the energy industry	Western Power will continue its customer engagement program throughout the AA4 period, and remains committed to talking with and listening to all key stakeholders as part of its business as usual. Ongoing advertising and public awareness campaigns will also be periodically reviewed and improved.
3	Customers want to interact with Western Power through multiple channels	Western Power will continue to develop its online and digital capabilities, as well as implementing improved customer relationship management systems.

[42] Customer insights and how they have informed specific items of expenditure are also discussed in the relevant sections of the operating and capital expenditure chapters of this document.

#	Insight	How we have incorporated this in our AA4 proposal
4	Local staff as well as accurate and timely support is essential for a positive customer experience	Western Power is investing in a new customer relationship management system. This will improve the quality and accuracy of information we can provide to customers. Western Power proposes customer service standard targets for the AA4 period that are higher than those set for the AA3 period, reflecting the progress we have made in this respect.
5	Customers believe Western Power should use emerging technologies to deliver improved customer outcomes	Western Power will continue to engage emerging technology trials, and pursue *non-capital alternative options*[43] as part of its investment program. Microgrid and standalone power system technology will continue to be assessed as economic alternatives to network solutions. Western Power will invest in improved supervisory control and data acquisition (**SCADA**) and communications technology to improve remote monitoring and control of the network. Western Power proposes to install advanced meters and associated infrastructure as the default meter, thereby enabling innovative tariff structures and remote reading.
6	Customers wants Western power to play a role in the supply of electricity into the future	
7	Customers who have been educated about electricity tariffs are more likely to support a time of use tariff	Western Power proposes a new time of use network tariff for residential and small business customers. We have found that when the benefits of time of use tariffs are clearly explained to customers, they general support it as a tariff option. Western Power will work with retailers to ensure customers are properly informed about time of use tariffs and understand the potential benefits. This will enable customers to make an informed choice on the way they are charged for their electricity use.
8	Customers who believe they are unable to alter their usage pattern do not support the implementation of a time of use tariff	Western Power is committed to periodically reviewing and improving its network tariffs to ensure they meet customers' requirements.
9	Customers who favour a time of use tariff are willing to pay for technology that allows them to monitor their usage	Western Power proposes to install advanced meters and associated infrastructure as the default replacement meter, thereby enabling innovative tariff structures and remote reading. Approximately 355,000 advanced meters will be installed during the period.

43 As per Section 6.41 of the Access Code.

#	Insight	How we have incorporated this in our AA4 proposal
10	Customers are accepting of occasional outages	Proposed investment during the AA4 period is designed to maintain current overall reliability levels rather than incur additional costs to improve reliability across the network. Investment will be targeted at pockets of the network that have the poorest reliability.
11	Accurate and frequent communication is essential during supply interruptions	Western Power will invest in an improved customer management system, and remains committed to maintaining the current high levels of customer service performance.
12	Longer outages are more disruptive to customers than frequent (short) outages	Western Power will invest in improved SCADA and communications to help reduce outage duration. We will also continue technology trials and implementing innovative solutions (such as the Kalbarri microgrid) as a way to address reliability issues in regional reliability hotspot areas.
13	A reliable source of electricity is essential for all customers, and customers are willing to spend money to ensure all people on the network have a reliable source of electricity	Western Power will target investment in the areas of the network that have the poorest reliability and power quality performance, with a view to providing a reliable source of electricity to all customers. Investment will not be designed to improve overall network performance. Areas with the highest network security risk will also be targeted.
14	Customers want Western Power to continue to improve network safety, although are divided on whether they should pay for it	Western Power will replace 2,196 km of overhead conductor and replace/reinforce around 125,000 wood poles. Forecast expenditure on pole and conductor management is designed to maintain the current level safety risk associated with these assets. More efficient asset management practices and lower replacement volumes means investment in conductor and wood pole management will be around 40 per cent lower than during the AA3 period, whilst maintaining network safety risk.
15	Customers want to see bushfire safety investment targeted in areas where it has the greatest impact	Western Power will use a risk based renewal approach to manage the poorest condition assets located in the highest risk areas. Safety and bushfire management investment will target parts of the network where mitigation activities will have the greatest impact.

4.1.5.1 Retailer, metering and generator forums

155. During the act phase, Western Power undertook extensive engagements on the proposed reforms and held a series of forums with generators, retailers and other interested stakeholders to share an overview of its proposed plans for the AA4 period, and to discuss key topics such as:

- potential tariff reforms
- advanced metering

- the Application and Queueing Policy (**AQP**)
- Generator Interim Access (**GIA**)
- the model Electricity Transfer Access Contract (**ETAC**)
- the Transfer and Relocation Policy
- the AA4 review process.

156. **Generator forum 3 May** – at the May generator forum, customers predominantly shared feedback on the proposed changes to the AQP. There was general support for Western Power's proposed AQP revisions, and feedback on the AQP has been factored into the AA4 proposal. A further round of consultation on the AQP occurred in August and September, and informed the final AQP revisions included in this AA4 proposal.

157. Western Power and the AEMO have provided regular updates to generators through a series of forums where progress of the GIA solution was shared, along with advice of the WEM rule amendments to enable GIA generators to be eligible for capacity credits. The GIA solution is outside the scope of the AA4 proposal. Western Power, the AEMO, and State Government are continuing consultation and development of GIA.

158. **Retailer forum 23 March** – at the March retailer forum, retailers were broadly supportive of the proposed advanced metering and tariff reforms. Retailers were generally positive about Western Power's proposal to increase the fixed component of network tariffs, as this will help ensure behind-the-meter generators (e.g. customers with rooftop solar) continue to pay a fair share of network costs. Proposed changes to demand based network tariffs were also supported. Retailers advised that any new time of use tariffs should be carefully designed to ensure the charging periods provide appropriate price signals to customers. Participants were invited to provide feedback and five submissions were received. A number of retailers also took up Western Power's offer for further follow up discussions.

159. **Metering forum 30 August** – the August forum was open to the public and focused on metering. It was attended by retailers, members of the public, vendors and other interested stakeholders. The forum was designed to provide information on Western Power's proposed changes to the Metering Model Service Level Agreement, and to give participants opportunity to ask questions and provide feedback. The forum also covered an update on the AA4 proposal, metering services framework and advanced metering infrastructure. Five submissions were received.

160. At the forum, participants were keen to know about the advanced metering program, including specifications, ability to access/utilise the data, and the remote capability of the meters and communication technology. Retailers sought to understand their involvement in advanced metering implementation and metering contestability. The proposed changes to a fixed standard metering service fee were supported.

4.1.5.2 June 2017 town hall meetings

161. In June 2017 Western Power shared an overview of our plans for AA4 with customers at a series of town hall meetings. The purpose of these meetings was to continue our conversation with customers and inform them of our future plans and how previous customer insights have been taken into account in the AA4 proposal. Town hall meetings were held in:

- Albany (7 June)
- Perth (12 June)
- Kalgoorlie (13 June)
- Bunbury (14 June)

- Geraldton (27 June).

162. All five customer town hall meetings were positively received, particularly in Kalgoorlie and Geraldton, where customers were encouraged to hear about the work Western Power is doing to improve its AQP, and to allow major customers to connect to the network more easily.

163. Customers at all forums were generally satisfied with the information Western Power presented with regard to the AA4 proposal. Western Power received no specific feedback at the forums on tariff reform or advanced meters.

164. These meetings were the final round of broad customer engagement before the AA4 proposal is submitted to the ERA in October 2017. However, Western Power will continue to liaise with customers and key stakeholders throughout the AA4 proposal review process, and throughout the AA4 period.

5. Performance during the AA3 period

165. This chapter sets out how Western Power performed over the five years of the AA3 period (2012/13 to 2016/17). It summarises the key customer services outcomes and the investment undertaken to achieve these outcomes. This chapter also highlights a number of service improvements made during the AA3 period, as well as improvements to processes and governance.

5.1 Overview of AA3 performance

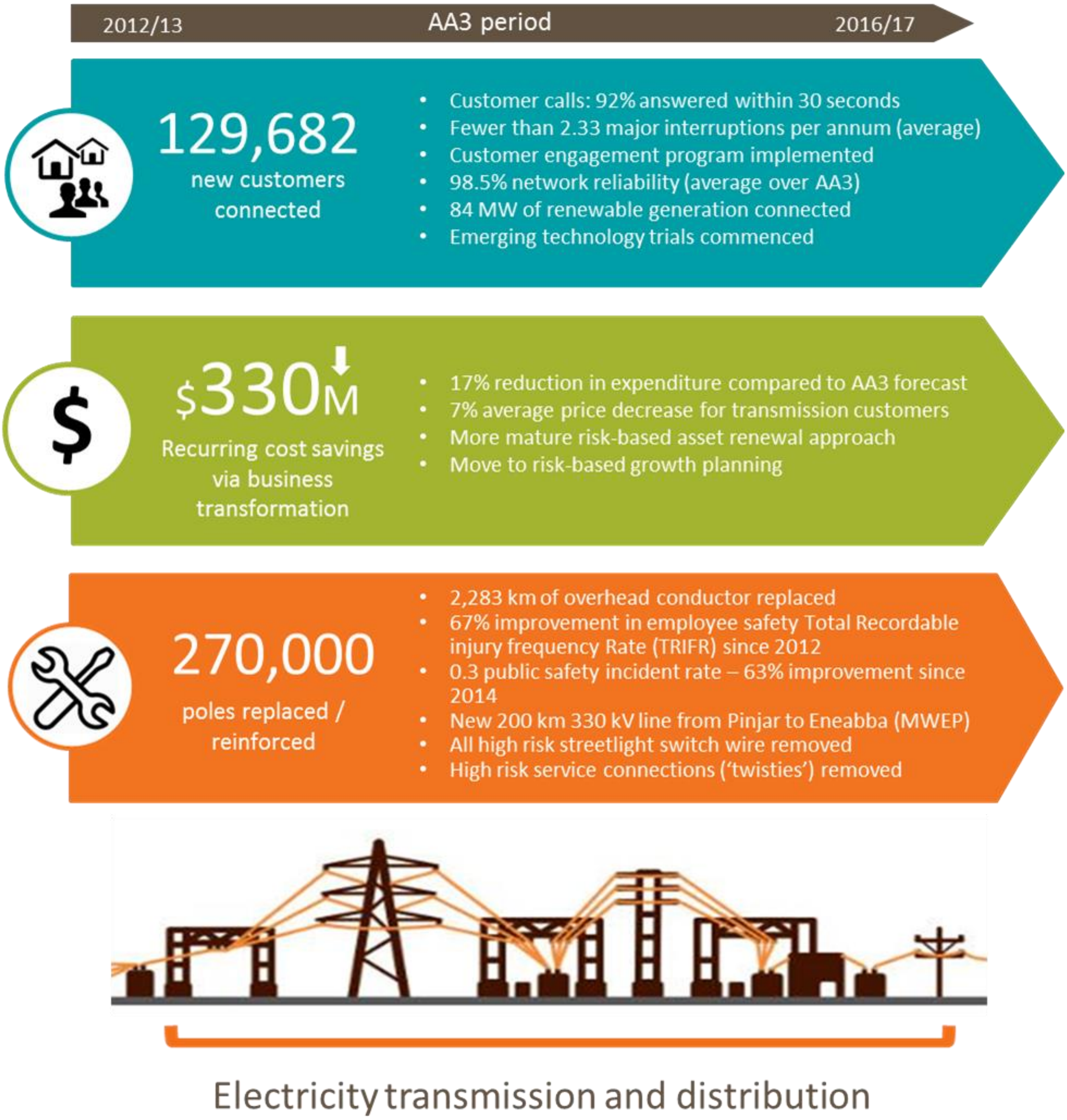
166. As outlined in Chapter 3, the AA3 period has been one of significant change in the Western Australian energy sector. The past five years have also seen Western Power rise to a number of challenges, addressing the highest priority public safety risks and becoming more customer focused, while also increasing our productivity.

167. Key achievements during the AA3 period include:

- **Meeting customers' needs** – we have delivered electricity and connected customers in a safe, reliable and affordable manner. In doing so we have improved performance against key reliability measures and complied with safety obligations set for the business. We have connected 84 MW of renewable generation to the network, as well as 129,682 new homes and businesses. The AA3 period also saw Western Power commence a comprehensive customer engagement program, designed to capture what customers expect from their electricity network operator.
- **Becoming more cost efficient** – actual total expenditure was around 17 per cent less than the allowances set by the ERA in the AA3 target revenue. We also commenced a whole of business efficiency review, culminating in the Business Transformation Program, which has already delivered $330 million of recurring cost savings. We are optimising our asset planning approach, improving our risk-based asset maintenance and renewal practices and considering non-traditional solutions to network challenges, including trials of new technology.
- **Delivery of major network projects** – we have replaced/reinforced more than 270,000 wooden poles (predominantly in rural areas), and replaced 2,283 km of overhead conductor. In doing so we have addressed some of the highest priority safety concerns while maintaining the overall level of public safety risk associated with our network. We have removed all known streetlight switchwire and the highest risk overhead customer service connections ('twisties') from the network reducing the safety risk to the public. We have continued the State Underground Power Program in partnership with the State Government and local governments to replace overhead power lines with underground power infrastructure. We also delivered the Mid-West Energy Project, the largest single capital project in more than 30 years, allowing new mining customers and windfarms to connect to the SWIS.

168. Figure 5.1 summarises some of the key achievements over the AA3 period.

Figure 5.1: Overview of key AA3 achievements



169. Further detail on AA3 expenditure, business improvements and service performance is provided in the following sections.

5.2 Expenditure during the AA3 period

170. Western Power invested $4,794 million in capital and incurred $2,389 million in operating costs to provide safe, reliable and efficient connection to the network during the AA3 period. This is a 17 per cent reduction in total expenditure compared with what was forecast in the AA3 final decision (see Table 5.1).

Table 5.1: Comparison of forecast and actual expenditure during the AA3 period, $ million real at 30 June 2017[44]

Expenditure type	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Operating expenditure						
Opex forecast	498.8	501.7	497.7	495.0	507.7	2,500.9
Opex actual	496.8	493.1	465.3	494.2	439.5	2,388.9
$ variance	-2.0	-8.7	-32.4	-0.8	-68.2	-112.1
% variance	0%	-2%	-7%	0%	-13%	-4%
Capital expenditure						
Capex forecast	1,175.1	1,352.5	1,182.4	1,177.1	1,275.2	6,162.3
Capex actual(1)	1,076.2	1,177.5	1,022.6	859.0	658.4	4,793.8
$ variance	-98.9	-175.0	-159.7	-318.1	-616.8	-1,368.5
% variance	-8%	-13%	-14%	-27%	-48%	-22%
Total expenditure						
Total forecast	1,673.8	1,854.2	1,680.1	1,672.1	1,783.0	8,663.2
Totex actual(1)	1,573.0	1,670.6	1,487.9	1,353.2	1,097.9	7,182.7
$ variance	-100.8	-183.7	-192.1	-318.9	-685.0	-1,480.6
% variance	-6%	-10%	-11%	-19%	-38%	-17%

171. The lower-than-forecast expenditure during the AA3 period is a result of the combination of:

- a conscious effort by the business to reduce operating costs and review its investment approach, in order to achieve long-term benefits for customers
- a slowdown in demand growth and economic activity leading to lower levels of investment in capacity expansion and customer-driven work during the course of the AA3 period.

172. As discussed in Chapter 3, during the AA3 period we commenced the Business Transformation Program, which saw Western Power begin to implement a suite of structural and procedural changes. At the end of June 2017, the program realised $330 million in recurring cost savings (see Table 5.2). The Business Transformation Program will continue into 2018, and expected efficiencies have been built into our operating and capital expenditure forecasts for the AA4 period.

[44] Total expenditure excluding non-revenue cap services and TEC.

Table 5.2: Business Transformation Program savings in recurrent costs at 30 June 2017 by work stream, $ million real at 30 June 2017

Work stream	Savings in recurrent costs realised at 30 June 2017
Asset management	151.9
Customer funded	12.1
External spend review	44.3
Field force central	19.8
Field force perform	30.5
ICT	11.8
Organisational model	35.6
Shared services	23.8
Total	**329.7**

173. Initiatives arising from the Business Transformation Program include:

- **depot refurbishment program** – we have transferred 206 staff, from the Bentley depot to Jandakot and Balcatta locations[45] to better serve customers. Benefit from efficiencies such as:
  - surplus scrap materials and stock was identified totalling $300,000
  - revising our processes to deliver better service to our customers
  - operational maintenance and customer funded teams now use the same stores, instead of running separate stores
  - designated areas for recycling
- **fleet advancements** – we have made significant changes to the way we manage and use our light and heavy fleet to improve driver safety by upgrading or changing light vehicles[46] and exploring the benefits of telematics[47] such as:
  - real-time asset location - dispatch immediate support in the event of an emergency.
  - emergency alerts – automatically triggered in the event of a roll over, high-impact collision or engagement of panic button.
  - fatigue management – monitor and manage the distance and length of trips.
  - monitor and measure driving behaviour – make informed decisions regarding driver education and training.
  - geo-fencing and landmark management – access reports and geo-fenced locations, such as sensitive locations and environmentally protected areas

45 The Bentley depot was reaching end of lease which provided for a great opportunity to realise downsizing efficiencies.

46 Light fleet (weighing less than 3.5 tonnes) will be owned and managed by Western Powers vehicle leasing partner Custom Fleet, commencing August 2017.

47 Telematics provides the option to use smart technology enabling better fleet management and improve driver safety.

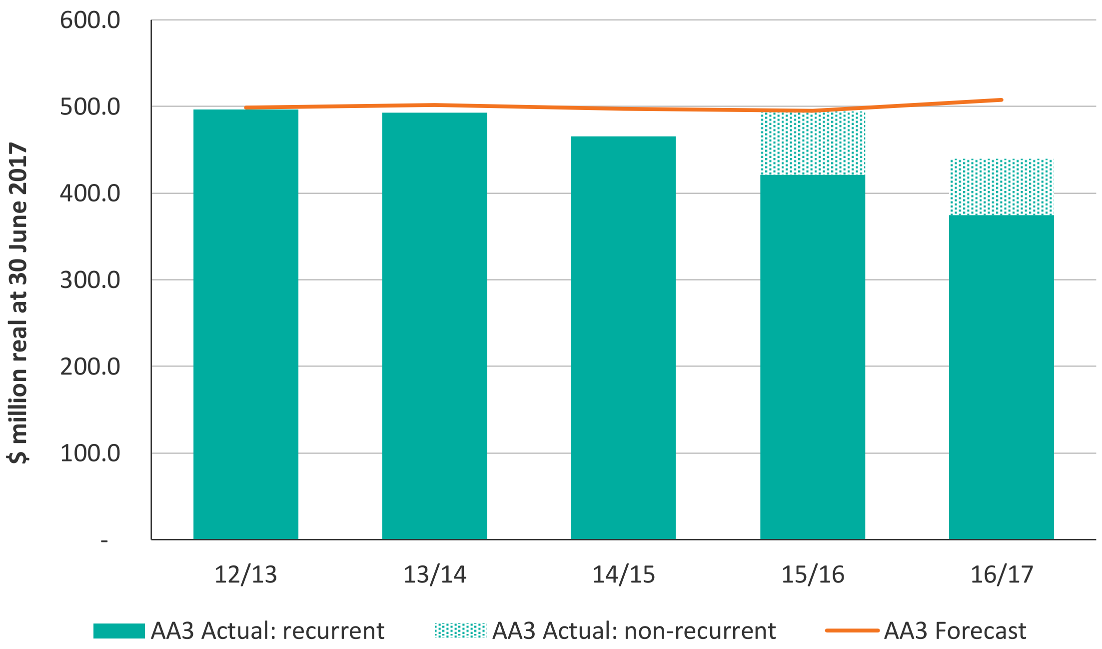
– installing reversing cameras to reduces Spotter requirements for reversing, parking and hooking up trailers as well as reducing potential accidents

- **conductor sampling and management** - by improving our knowledge and understanding of the current condition, aging characteristics and remaining life of our conductor assets we are then able to better influence our decision making, planning and delivery. This targeted strategy is anticipated to deliver $15 million recurring savings per year from 2016/17 financial year.

5.2.1 AA3 operating expenditure

174. Operating costs during the AA3 period were around $112 million lower than forecast (see Figure 5.2). This is due to efficiencies achieved throughout the business, including those driven by the Business Transformation Program.

Figure 5.2: Comparison of AA3 forecast and actual opex, $ million real at 30 June 2017



175. Opex efficiency initiatives arising from the Business Transformation Program include:

- **standardising depot tasks** – by changing our scheduling approach, we have reduced the size of work crews that are sent to jobs (depending on the work activity). This reduces the operating cost per job, while also freeing up resources to undertake work elsewhere. This program has achieved $3 million of savings during 2016/17 and is expected to deliver around $8 million of recurring savings from 2017/18 onwards
- **updated vegetation management strategy** – we have adopted a risk-based approach to vegetation management across both the transmission and distribution lines, including investigation of alternative vegetation management practices and treatment options. This program has delivered $5 million worth of savings during 2015/16 and is expected to deliver around $10 million recurring savings per annum from 2016/17 onwards
- **HR solutions centre** – we have launched the self-service portal whereby employees have access to more automated information and online processing which has increased efficiencies across all

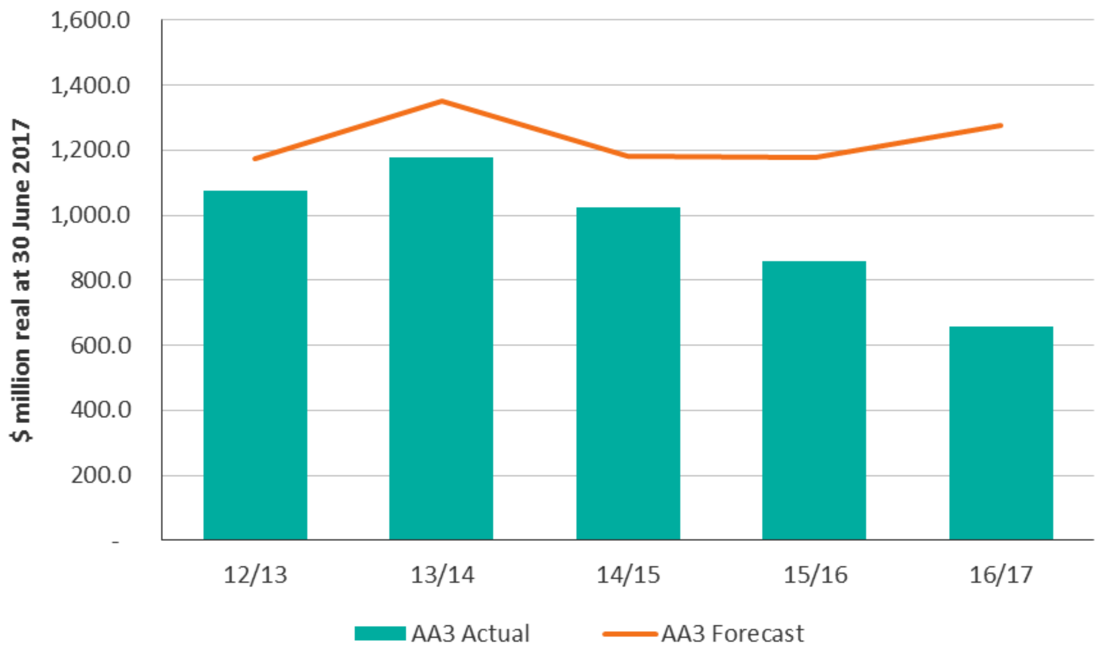
areas of the business. The program has achieved $3 million of savings during 2016/17 and is expected to deliver around $4 million recurring savings from 2017/18 onwards.

176. Further examples of opex efficiencies achieved (and forecast) via the Business Transformation Program are provided in Chapter 7.

5.2.2 AA3 capital expenditure

177. Over the five-year period 2012/13 to 2016/17, Western Power invested $4,794 million in capital expenditure compared to a forecast $6,162 million. Figure 5.3 provides a comparison of actual and forecast capex over the AA3 period.

Figure 5.3: Comparison of AA3 forecast and actual capex, $ million real at 30 June 2017



178. Actual capital investment over the AA3 period is 22 per cent less than that forecast for AA3, driven by:

- our risk based approach to asset management, based on the likelihood and consequence of individual asset failure where investment is prioritised to address assets at the highest risk of failure and greatest consequence. This maturing and innovative approach to asset management reflects industry best practice and has delivered network management savings across a number of capital expenditure categories
- a fresh approach to continuous improvement that lead to our Business Transformation Program, which has identified a number of process improvements and efficiency initiatives
- efficiently minimising costs through our approach to cost estimation, our works optimisation process, our procurement practices and the competitive tendering of our expenditure delivered by external parties
- optimising investment solutions by considering alternative options in place of like for like asset replacement of existing network assets, such as network reconfiguration enabling load transfer
- a slowdown in the growth rate of peak demand following eight-years of reasonably strong growth

- a reduction in customer-driven work compared to what was forecast due to weakened economic conditions and a significant slowdown in the growth of the mining sector in Western Australia.

179. Notably, $1,186 million (or 87 per cent) of the less-than-forecast investment during the AA3 period was in the growth and pole management expenditure categories, which are subject to the investment adjustment mechanism (**IAM**). This mechanism ensures that where Western Power does not spend as much as forecast in these expenditure categories, the revenue associated with this amount is returned to customers in the next access arrangement period. Through the IAM we will return $39.5 million (in net present value terms as at 30 June 2017) to customers during the AA4 period.

180. Table 5.3 shows actual capital investment compared to forecast by regulatory category.

Table 5.3: AA3 total capital expenditure – major capital projects and programs, $ million real at 30 June 2017

Expenditure category	Forecast	Actual	$ variance	% variance
Transmission				
Asset replacement and renewal	177.0	185.8	8.8	5.0%
Growth	1,372.7	564.2	-808.5	-58.9%
Compliance	140.4	112.4	-28.0	-20.0%
Improvement in service	83.2	60.2	-23.0	-27.2%
Transmission total	1,773.2	922.5	-850.7	-48.0%
Distribution				
Asset replacement and renewal	1,750.2	1,810.1	59.9	3.4%
Growth	1,847.9	1,484.3	-363.6	-19.7%
Compliance	443.5	325.5	-118.0	-26.6%
Improvement in service	35.8	24.6	-11.2	-31.4%
Distribution total	**4,077.4**	**3,644.5**	**-433.0**	**-10.6%**
Corporate total	**311.5**	**226.9**	**-84.7**	**-27.2%**
AA3 total capital expenditure	**6,162.2**	**4,793.8**	**-1,368.4**	**-22.2%**

5.2.2.1 Transmission network outcomes

181. Western Power invested $564 million in transmission growth projects to expand the capacity of the transmission network to help us to meet growth in demand and connect new customers. This represented 61 per cent of the total AA3 transmission capital investment and included:

- delivery of one of Australia's largest transmission projects – the Mid-West Energy Project. This involved the construction of a 330 kV double circuit transmission line from Pinjar to Eneabba, enabling the connection of mining projects and electricity generators including wind farms in the Mid-West region.

- established a number of new substations to accommodate increasing demand and create additional feeder capacity to allow for load growth, additional distribution transfer capacity, and connection of new large customers
- connected major customer loads and additional generation capacity across the Western Power network.

182. We also invested $358 million in transmission non-growth activities. This investment generally related to maintaining the provision of covered services to existing customers to ensure the ongoing safe and reliable operation of transmission assets.

5.2.2.2 Distribution network outcomes

183. During the AA3 period, Western Power invested $1,484 million on distribution growth projects to expand the capacity of the distribution network to meet growth in demand and connect new customers. This represented 41 per cent of the total investment in distribution capital activities and included:

- connecting 129,682 new customers to the distribution network increasing total customers connected by approximately 12 per cent to more than 1.1 million customers
- installing new feeders and reinforcing existing feeders to increase capacity, reduce feeder peak loading and reduce the risk of long duration outages.

184. We invested the remaining 59 per cent or $2,160 million on distribution non-growth activities including:

- replacing 82,114 and reinforcing 188,009 distribution poles predominantly in rural areas in accordance with the Energy*Safety* Order 01-2009 to address urgent safety risks associated with the ageing wood pole network with the Director of Energy Safety stating that Energy*Safety* is satisfied that Western Power has complied with the Order as at 31 December 2015[48]
- replaced 278,339 overhead service connections and successfully concluded a six-year long safety driven program to remove all known streetlight switchwire from the network, reducing the safety risk to the public
- completed State Underground Power Program (**SUPP**) projects in partnership with the State Government and local governments in a number of metro and rural locations
- installed 145,516 meters for new connections and replaced 179,509 existing meters as part of network maintenance and customer requested services
- replaced 2,283 km of deteriorated overhead lines, reducing the number of unassisted failures
- commenced standalone power systems trial in Ravensthorpe area.

5.2.2.3 Corporate expenditure outcomes

185. In AA3 we invested $227 million on corporate support activities, including the following IT investments to improve the effectiveness of key operational processes and work practices:

- field mobility services, which provided a mobile solution to the field workforce for distribution asset maintenance work to support the capture of work status and asset data, enabling real

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[48] Page 4, Order No. 01-2009 Review of Western Power's Compliance, Energy*Safety,* 10 June 2016.

- time updates to enterprise systems, resulting in enhanced data management and process efficiency
- the Network Risk Management Tool, which extended previous development of an analytics-based approach to providing risk scores for distribution assets, considering both likelihood and consequence of failure, resulting in better investment decisions and capital management
- a holistic inspection and scoping strategy for distribution assets, to combine inspection and scoping of remediation work and the capture of access information in the same visit, and automation of the process for identifying specific assets requiring work, as well as the process for creating executable work orders
- an enhanced process for specifying planned work on individual distribution assets, by adopting the same logic as the previous initiative to provide a medium-term view (up to two years ahead) to correlate planned work against assets.

186. Key depot facilities were upgraded in order to comply with legislative requirements and meet the operational needs of the business. This included rationalisation of facilities including relocation of the vehicle maintenance facility from Perth Airport depot to Kewdale, relocation of functions from Bentley depot to Balcatta and Jandakot, and closure the of Perth Airport and Bentley leased depots.

187. We also completed the construction of a bespoke pole break test facility to assist in the management of Western Power's pole network. The test facility supports the strategic management of wood poles through a better understanding of pole behaviour and how they degrade with age, which contributes to optimised replacement and reinforcement works.

188. Further discussion on capex during the AA3 period, including reasons for variance from forecast, is provided in the AA3 Capital Expenditure Report (see Attachment 5.1). Further information is available in the AA3 Capital Expenditure Variance Analysis Report provided at Confidential Attachment 5.2.

5.3 Service standard performance

189. Western Power operates under a revenue cap form of regulation. Revenue cap regulation provides certainty of revenue, and offers customers some certainty around network prices. A revenue cap is often accompanied by a service standard incentive scheme to ensure that services are not compromised in the pursuit of incentives to reduce costs. Western Power's incentive mechanisms have been designed to penalise a decline in performance, but also provides an incentive to improve service where it is valued by customers.

190. Western Power's access arrangement accounts for service standard performance in two key elements:

1. **service standard benchmarks (SSB**) – compliance targets set at minimum service levels that must be achieved. There are no financial rewards or penalties associated with SSB performance
2. **the service standard adjustment mechanism (SSAM)** – the financial incentive scheme to provide Western Power with rewards and/or penalties for performance against service standard targets (**SST**).

191. The service performance measures in the AA3 incentive scheme cover:

- **reliability of electricity supply in the distribution and transmission networks**, which measures the frequency and duration of network interruptions experienced by customers

- **security of electricity supply,** which measures the percentage of time transmission circuits are available
- **customer service**, which measures how well the business engages with customers in relation to non-technical services including such things as call centre performance, notification of planned outages and timely streetlight repairs.

192. Measures in the incentive framework must directly relate to one or more of the reference services provided to customers. Measures should provide information that is meaningful to customers, and be an accurate reflection of actual performance.

193. During the AA3 period, Western Power achieved 17 out of 17 SSBs in two out of five years, while achieving 16 out of 17 in the other three. Figure 5.4 provides a summary of performance against SSBs.

Figure 5.4: Western Power's performance against AA3 SSBs

	AA3 SSBs	12/13	13/14	14/15	15/16	16/17
Transmission network	Circuit availability	✓	✓	✓	✓	✓
	SMI meshed	✓	✓	✓	✓	✓
	SMI radial	✓	✓	✓	✓	✓
	LOSEF >0.1 and ≤1 system mins	✓	✓	✓	✓	✓
	LOSEF >1 system mins	✓	✓	✓	✓	✓
	Average outage duration	✓	✓	✓	✗	✓
Distribution network	SAIDI CBD	✓	✓	✓	✓	✓
	SAIDI urban	✓	✓	✓	✓	✓
	SAIDI rural short	✓	✓	✓	✓	✓
	SAIDI rural long	✓	✓	✓	✓	✓
	SAIFI CBD	✓	✓	✓	✓	✓
	SAIFI urban	✓	✓	✓	✓	✓
	SAIFI rural short	✓	✓	✓	✓	✓
	SAIFI rural long	✗	✗	✓	✓	✓
Call centre	% calls responded to in <30s	✓	✓	✓	✓	✓
Street lighting repair time	Metropolitan	✓	✓	✓	✓	✓
	Regional	✓	✓	✓	✓	✓

✓ = SSB met
✗ = SSB not met

Notes:

(1) **SMI** = system minutes interrupted, **LoSEF**= loss of supply event frequency, **SAIDI** = system average interruption duration index, **SAIFI** = system average interruption frequency index

194. Service performance generally improved over the AA3 period. The SSAM, which presents a more detailed picture of service performance, shows that Western Power exceeded most SSTs during the AA3 period.

195. Unlike the SSB framework (which is a measure of compliance), the SSAM provides rewards/penalties for service improvement/degradation measured against the SSTs set at the beginning of the access arrangement period. The framework is set to allow the network business to accrue rewards or penalties against each measure each year, culminating in a net reward or penalty to be added/subtracted from target revenue in the following access arrangement period. Figure 5.5 shows Western Power's performance against the 14 measures[49] included in the SSAM.

Figure 5.5: Western Power's performance against AA3 SSTs

AA3 Performance against SSTs		12/13	13/14	14/15	15/16	16/17	Net reward/penalty
Transmission network	Circuit availability	+	−	+	+	+	+
	SMI radial	+	−	+	+	+	+
	LOSEF >0.1 and ≤1 system mins	+	+	=	+	+	+
	LOSEF >1 system mins	+	+	+	+	=	+
	Average outage duration	−	−	−	−	+	−
Distribution network	SAIDI CBD	+	+	−	−	+	+
	SAIDI urban	+	+	+	+	+	+
	SAIDI rural short	+	+	+	+	+	+
	SAIDI rural long	−	−	−	−	−	−
	SAIFI CBD	+	−	−	+	+	+
	SAIFI urban	+	+	+	+	+	+
	SAIFI rural short	+	+	+	+	+	+
	SAIFI rural long	−	−	−	+	+	−
Call centre	% calls responded to in <30s	+	+	+	+	+	+

+ = Performance better than SST (reward)
− = Performance worse than SST (penalty)
= = Performance equal to SST (neutral)

196. The AA3 SSAM was designed so that, on average, performance would exceed the SST 50 per cent of the time, and fall below the SST 50 per cent of the time, the net outcome being that overall service levels are maintained.

49 The system minutes interrupted meshed and two streetlight measures that feature in the SSB framework are not included in the SSAM.

197. As per the SSAM design, Western Power incurred a combination of rewards and penalties against each SST over the course of the AA3 period. However, performance exceeded the SST more often than 50 per cent of the time for 11 of the 14 measures. The net result is that customers benefitted from overall service improvement in most areas of the network, with rural long feeders being the exception. Rural long SAIFI has improved in the final two years of the AA3 period, meaning customers on these feeders are generally experiencing fewer outages today than they were at the beginning of the AA3 period.

198. Our strong performance against service incentives results in a net financial reward under the SSAM of $252 million (in present value terms), to be added to target revenue for the AA4 period. Details of the SSAM calculation, including penalties/rewards incurred each year, is provided in Chapter 10.

199. The following sections provide a summary of how Western Power has performed during the AA3 period in the following areas of customer service:

- reliability of electricity supply
- security of electricity supply
- call centre performance
- street light repair
- public safety.

200. Note public safety does not feature in the service incentive framework, but is a key indicator of a network business' performance. In addition, Western Power also reports and publishes network safety statistics on a quarterly basis under regulation 32 of the *Electricity (Network Safety) Regulations 2015*, which require Western Power to publish outcomes for the network safety performance incident types specified under regulation 31 of the *Electricity (Network Safety) Regulations 2015*.

5.3.1 Reliability of electricity supply in the distribution network

201. Western Power has improved reliability of electricity supply in the distribution network over the course of the AA3 period and has performed significantly better than targeted levels in most areas of the network.

202. 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**).

203. Figure 5.6 to Figure 5.13 shows performance in relation to the duration (SAIDI) and frequency (SAIFI) of outages on each of the four distribution feeder types (CBD, urban, rural short, rural long). Note, a lower number represents an improvement in service for these measures.

Figure 5.6: Distribution network reliability, SAIDI – CBD

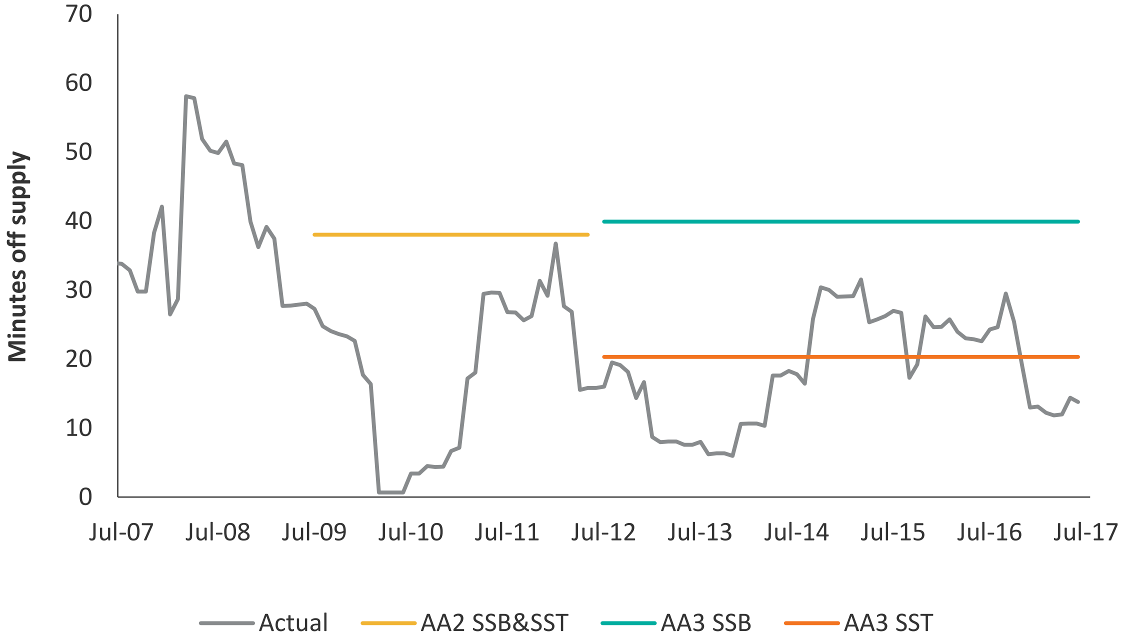
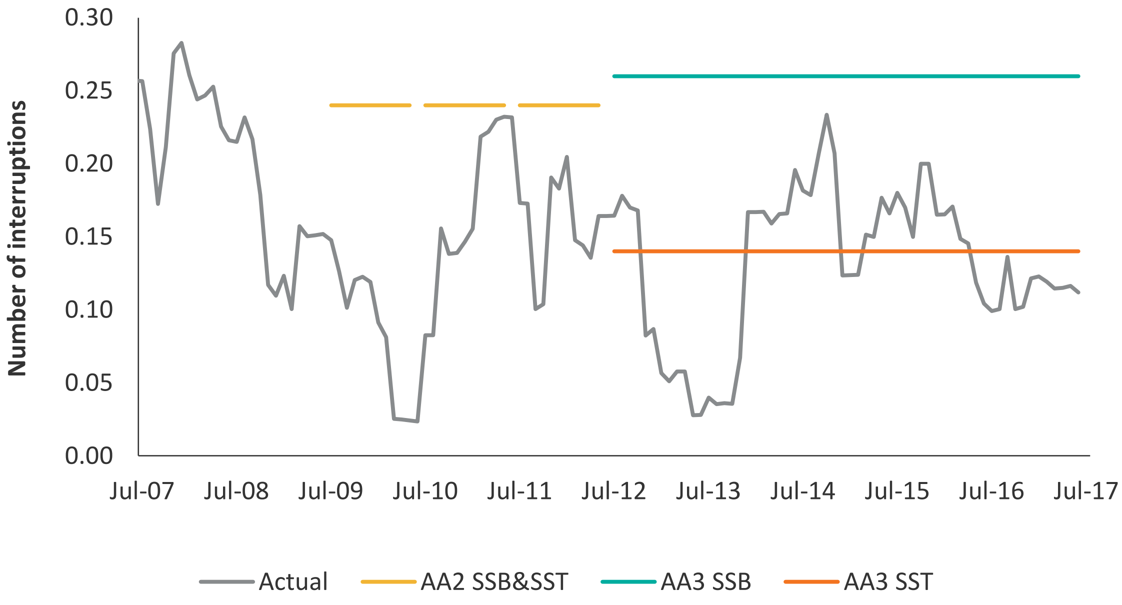


Figure 5.7: Distribution network reliability, SAIFI – CBD



204. SAIDI and SAIFI within the CBD has been tracking within the SSB, reflecting the high levels of reliability in this part of the network. As per the SSAM design, performance has fluctuated above and below the SST over the course of the AA3 period. Underground cable failures in 2013/14 contributed to an increase in SAIDI and SAIFI mid-AA3 period, however overall performance was in line with targets.

Figure 5.8: Distribution network reliability, SAIDI – urban

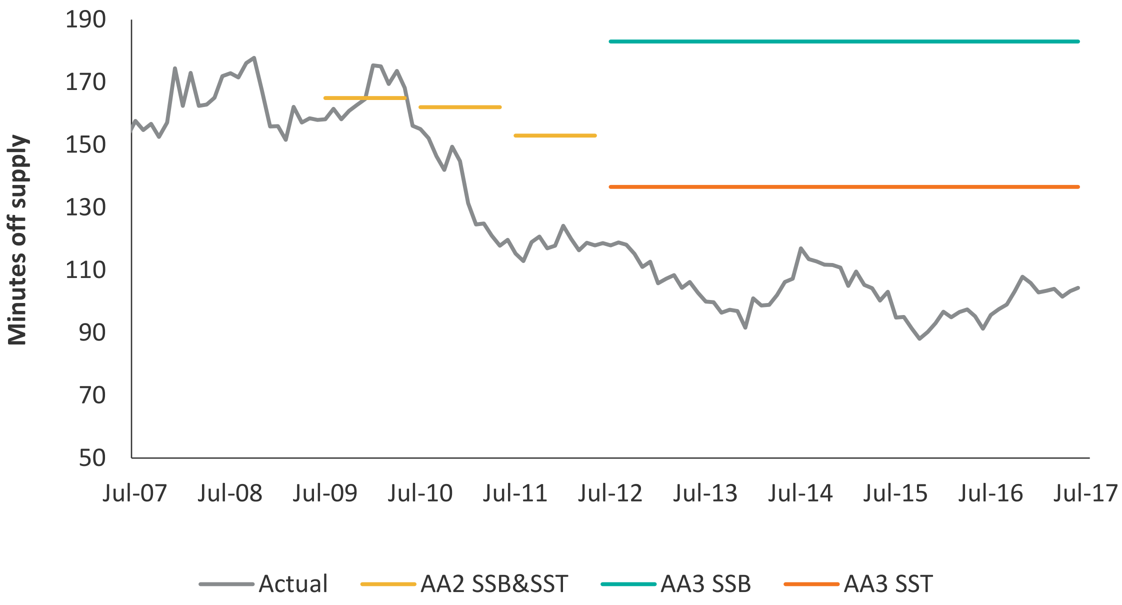
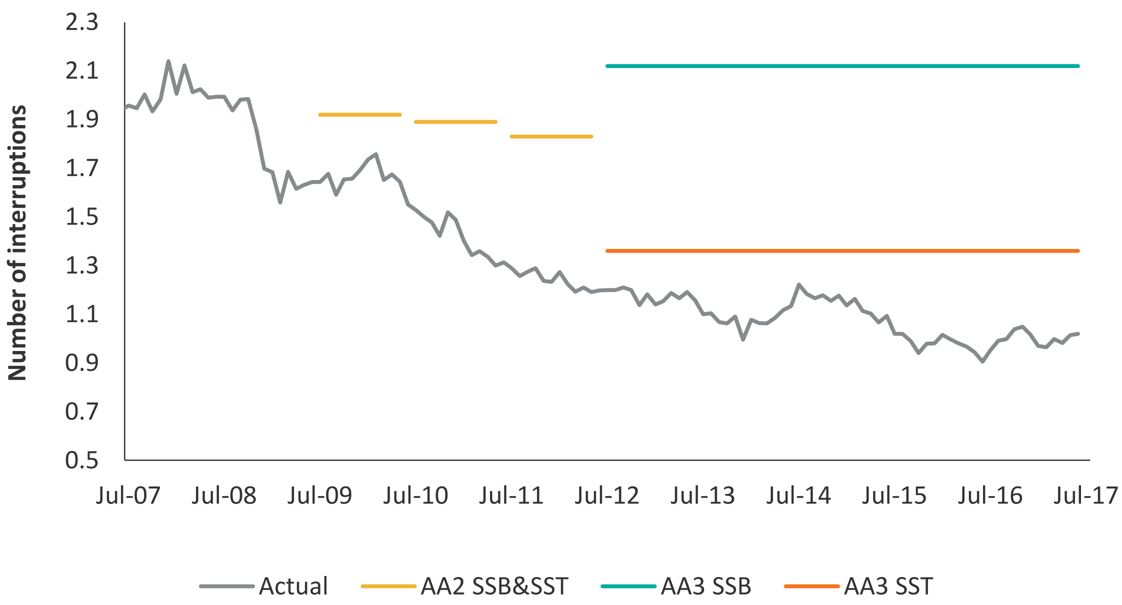


Figure 5.9: Distribution network reliability, SAIFI – urban



205. SAIDI and SAIFI in urban areas of the network have been consistently better than the SST. The high performance is due to the ongoing works and vegetation management program, combined with favourable weather and a lower than expected number of vehicles and fauna coming into contact with the network.

Figure 5.10: Distribution network reliability, SAIDI – rural short

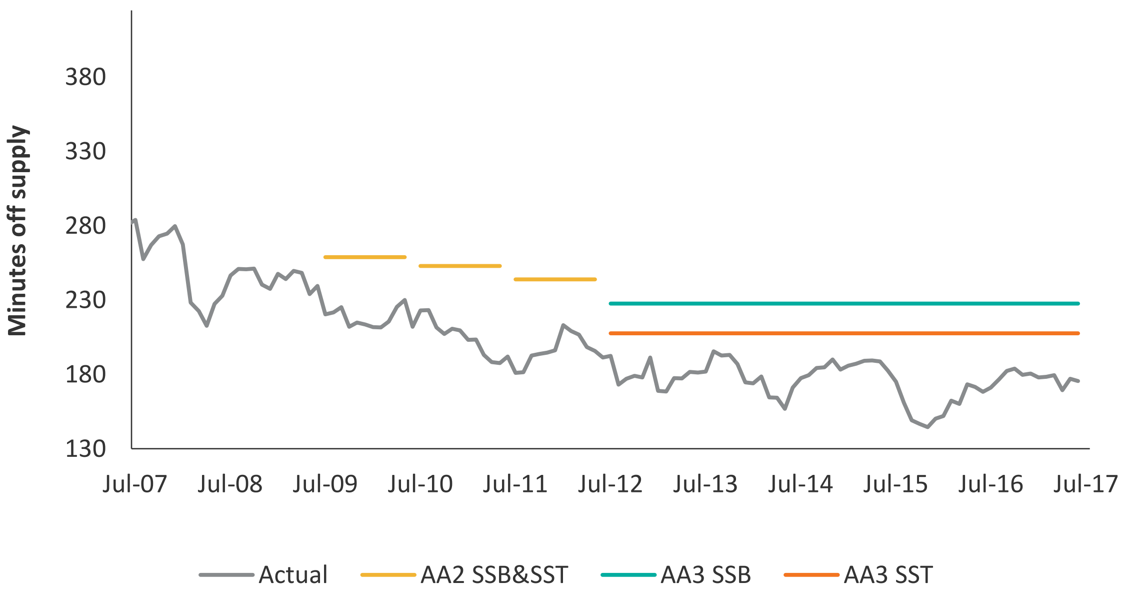
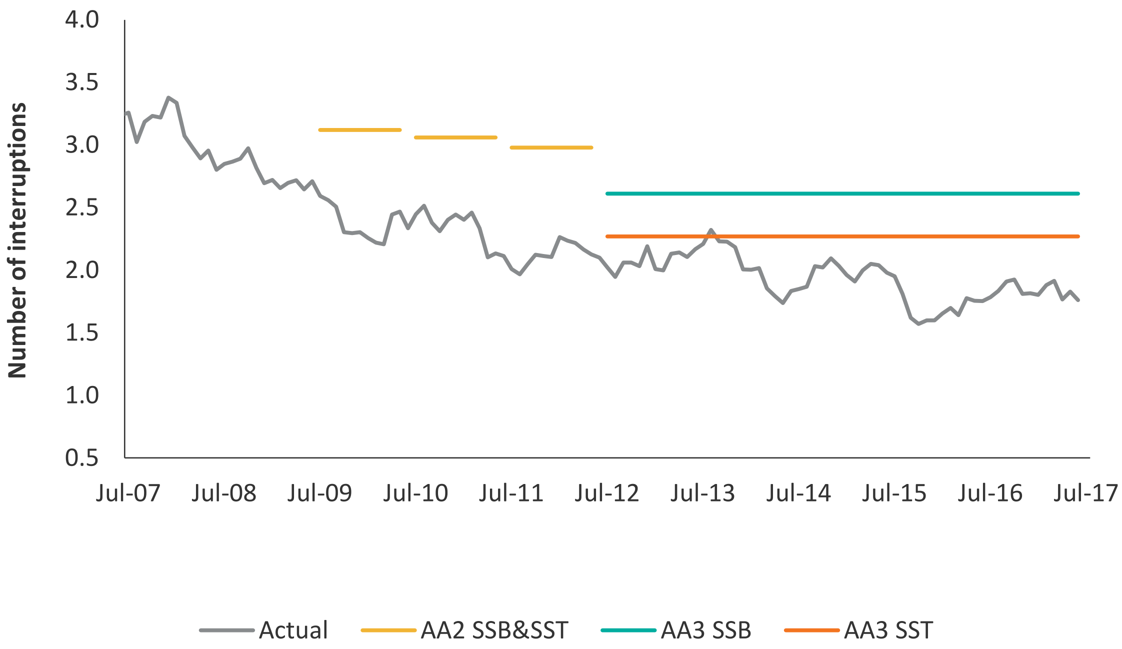


Figure 5.11: Distribution network reliability, SAIFI – rural short



206. As per urban areas of the network, reliability performance on rural short feeders has been good, and consistently better than the SST.

Figure 5.12: Distribution network reliability, SAIDI – rural long

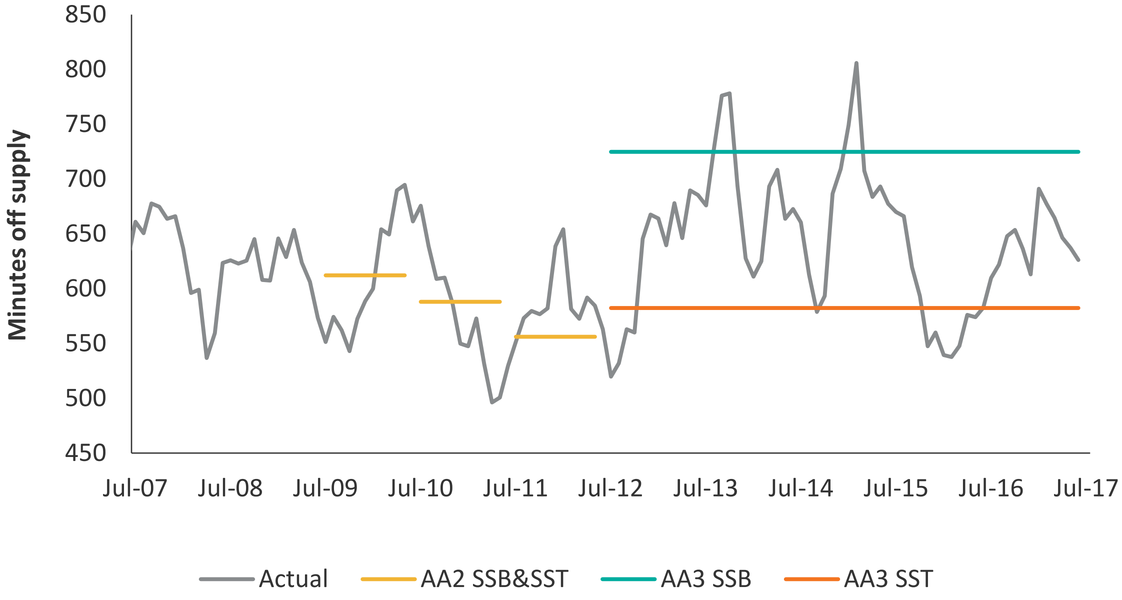
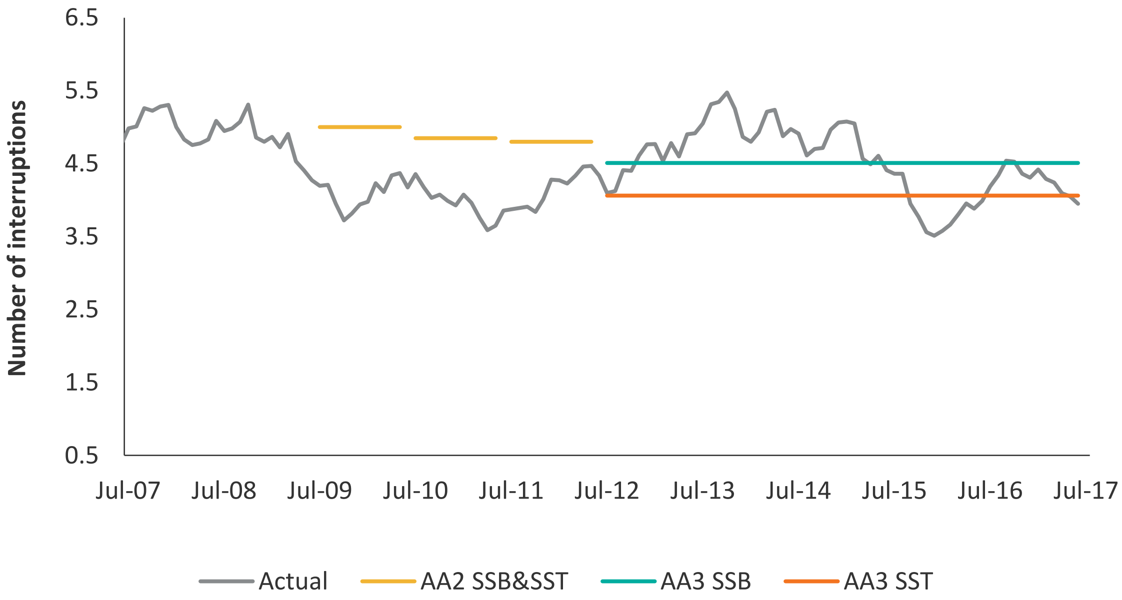


Figure 5.13: Distribution network reliability, SAIFI – rural long



207. Reliability on rural long feeders has generally been better than the SSB throughout the period. SAIDI rural long performance has been better than the SSB in all five years. Despite the spikes in SAIDI in October 2013 and February 2015, the rolling average duration of interruptions at year end has been within the minimum standards. The frequency (SAIFI) of outages on rural long feeders was worse than the SSB in 2012/13 and 2013/14, due to adverse weather conditions.

208. Performance compared to SST for both SAIDI and SAIFI has been worse than the target in most years. This is because feeders in rural areas tend to be more exposed to lightning and incidents of birds and other animals contacting overhead assets than feeders located in urban areas. Rural long feeders also tend to have low levels of redundancy, providing less opportunity to re-route power while repairs are being carried out.

209. Rural long reliability improved towards the end of the AA3 period. In 2015/16 and 2016/17 rural long SAIFI surpassed the SSB and SST. This is due to Western Power commencing its 'hotspot' approach, which identifies and targets the poorer performing areas of the distribution network. In 2015/16 there was a concerted effort to improve rural long SAIFI performance by increasing activities such as insulator siliconing and improving vegetation management. Continued high levels of maintenance activity in rural areas will be required during the AA4 period if the business is to meet its SAIDI and SAIFI rural long targets.

210. Detailed commentary on SAIDI and SAIFI performance during the AA3 period, including causes of outages, and remedial activities, is provided in Western Power's 2012/13 to 2016/17 annual Service Standard Performance Reports, available on the ERA's website.

5.3.2 Reliability of electricity supply in the transmission network

211. Reliability performance in the transmission network has generally been strong. We achieved all transmission SSBs in every year except 2015/16, where the failure of two transformers at Muja meant we did not achieve the average outage duration SSB that year. Performance against SSTs was mixed, with net performance over the AA3 period in four out of five transmission measures being higher than the target.

212. The reliability of the transmission network is monitored in terms of duration and frequency, however, the measures are different to those used on the distribution network. The duration of outages is measured as system minutes interrupted on meshed and on radial[50] networks and an average outage duration measure. The frequency of outages is covered by two measures: one that records the loss of supply event frequency of duration longer than 0.1 system minute but less than or equal to 1 minute and one that records loss of supply events longer than 1 system minute.

213. Figure 5.14 to Figure 5.18 shows our performance in relation to the five transmission reliability measures. Note a lower number represents an improvement in service for these measures.

50 Meshed networks are where there is a high level of interconnectivity in the grid, allowing connection to multiple generation sources. Meshed networks typically have a high level of redundancy, meaning power can be re-routed while faults are repaired. Radial networks have a simpler design, where electricity from a large single supply radiates out to progressively lower voltage lines. Redundancy levels tend to be lower than in meshed network, and faults can result in longer outages.

Figure 5.14: Transmission network reliability, loss of event supply frequency >0.1 and ≤1.0

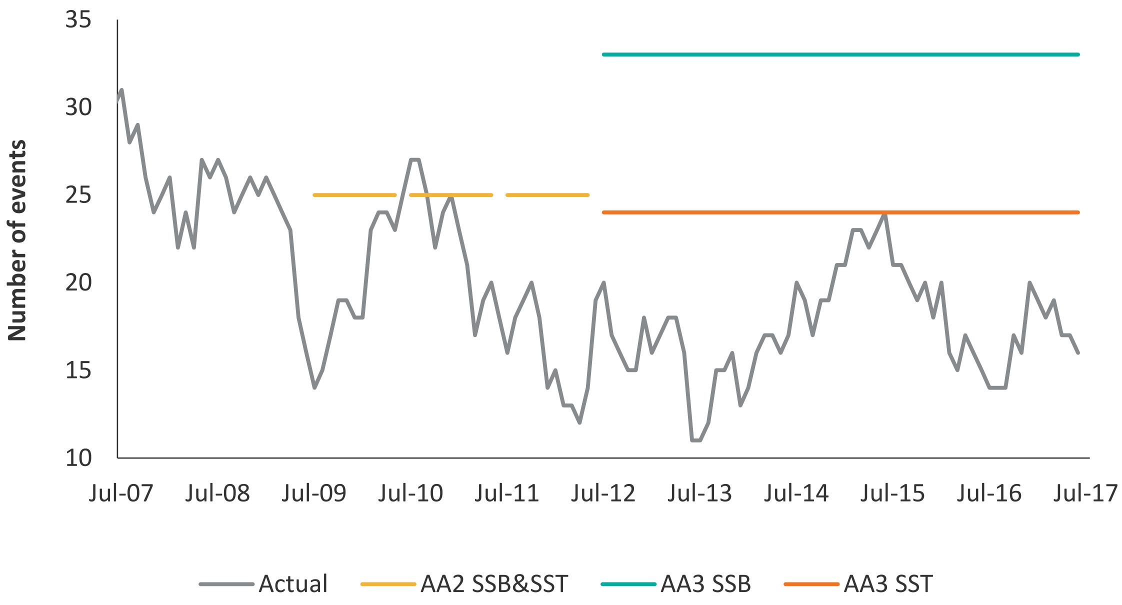
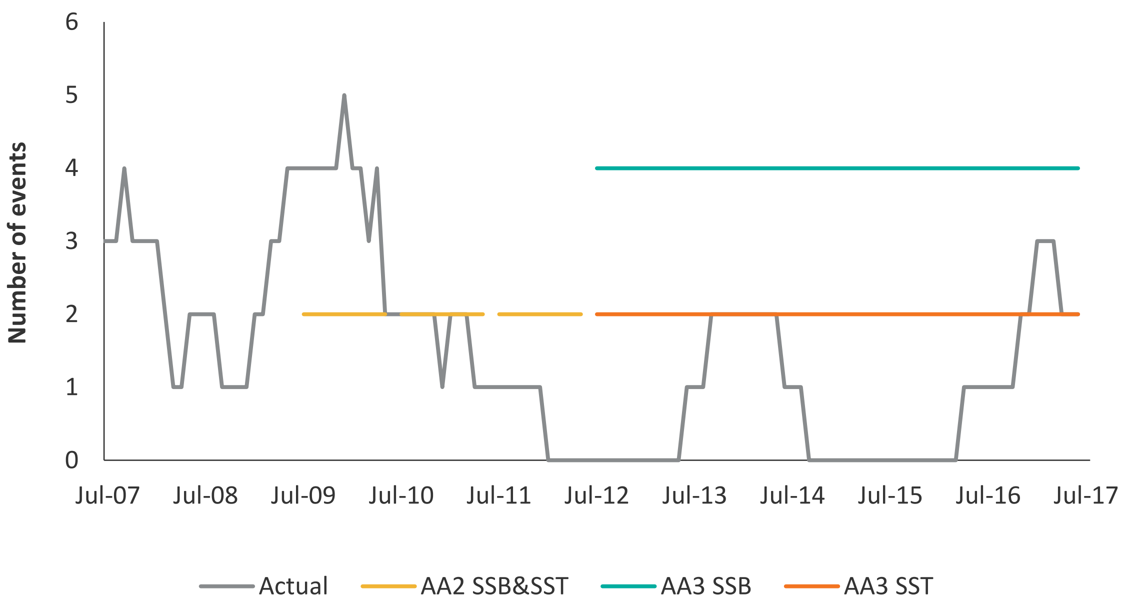


Figure 5.15: Transmission network reliability, loss of event supply frequency >1



214. All SSBs relating to loss of event supply frequency have been achieved each year. Performance against the SSTs has also been good. Loss of event supply frequency >0.1 has generally tracked better than SST and represents an improvement compared to the AA2 period.

Figure 5.16: Transmission network reliability, system minutes interrupted meshed

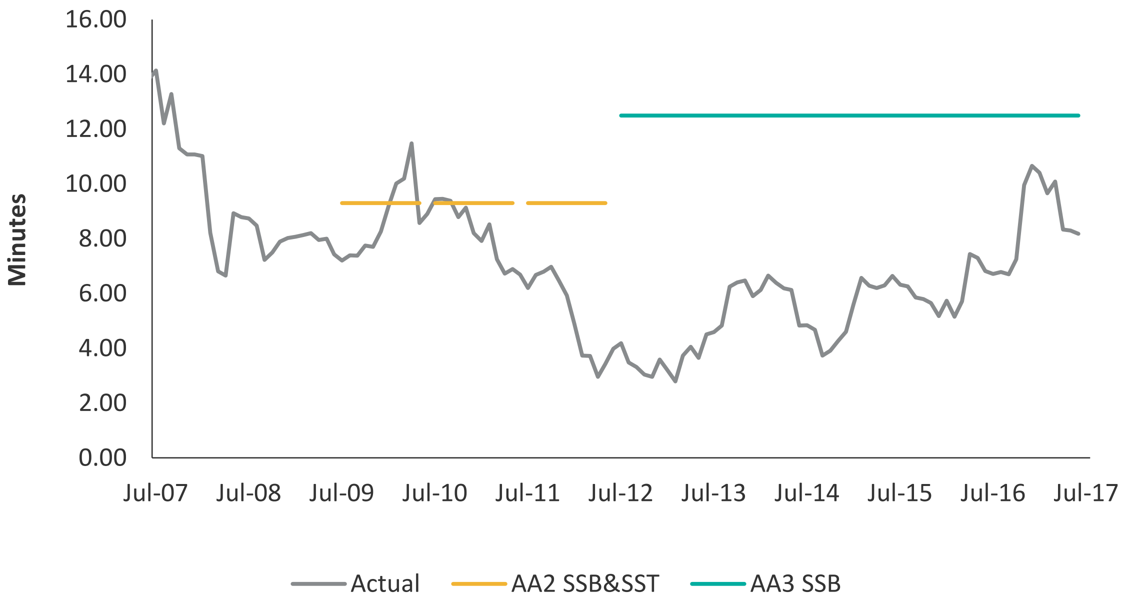
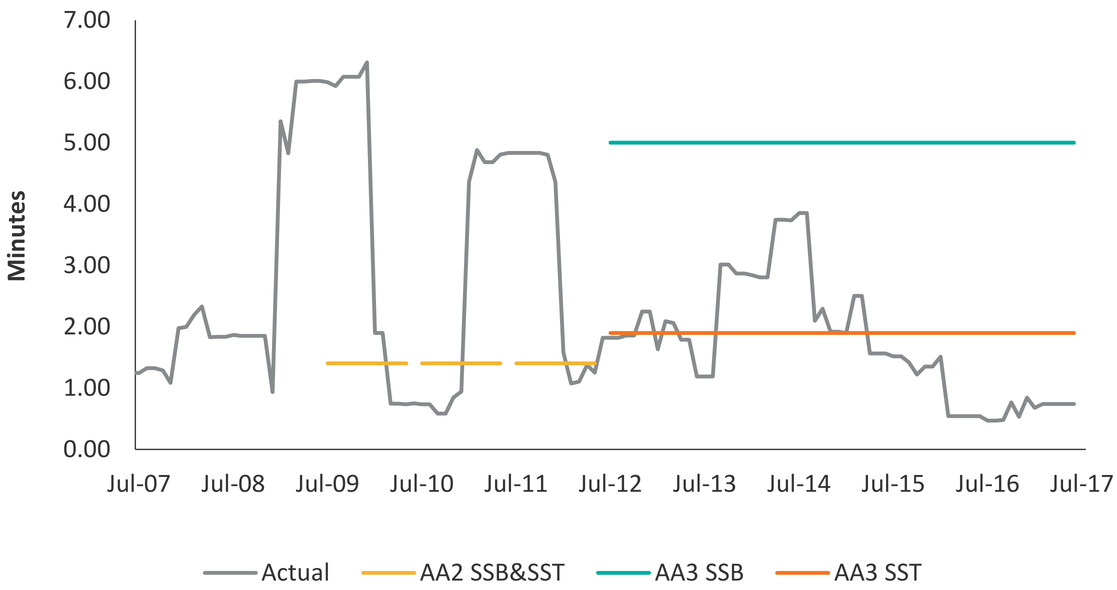


Figure 5.17: Transmission network reliability, system minutes interrupted radial

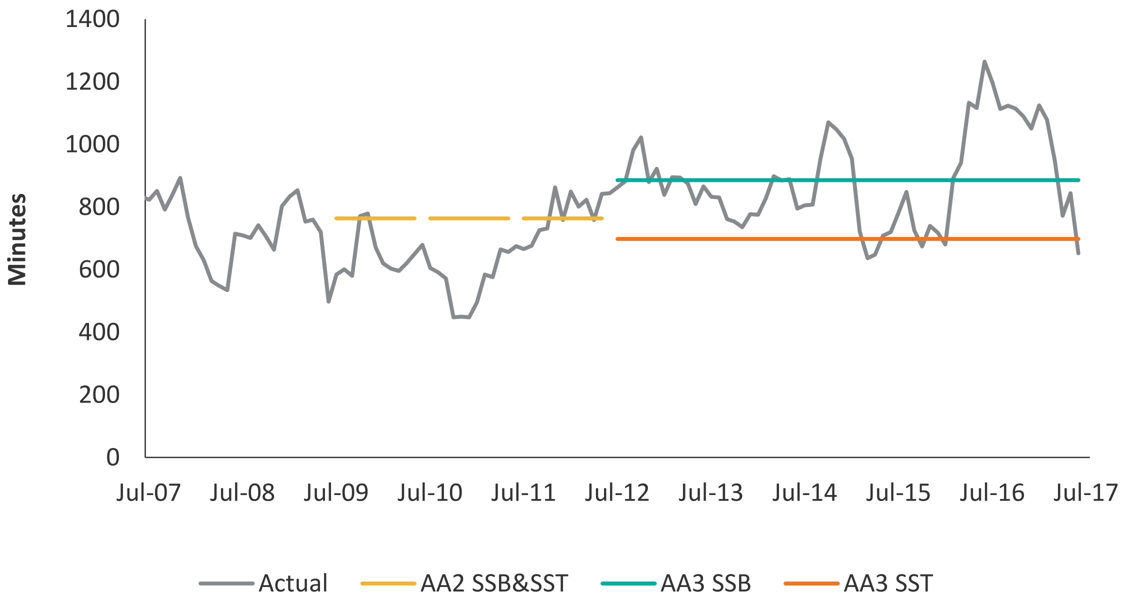


215. System minutes interrupted radial and system minutes interrupted meshed[51] performance has been better than the SSB throughout the AA3 period. As per the SSAM design, system minutes interrupted radial performance has fluctuated above and below the SST. However, overall system minutes interrupted

51 Note system minutes interrupted meshed has an SSB but is not part of the SSAM and therefore has no SST.

meshed reliability has been good, resulting in net financial reward under the SSAM at the end of the AA3 period.

Figure 5.18: Transmission network reliability, average outage duration



216. Performance against the average outage duration SST has been lower than the target in four out of five years. However, the business has achieved the SSB in every year except one (due to the Muja transformer failures in 2014/15).

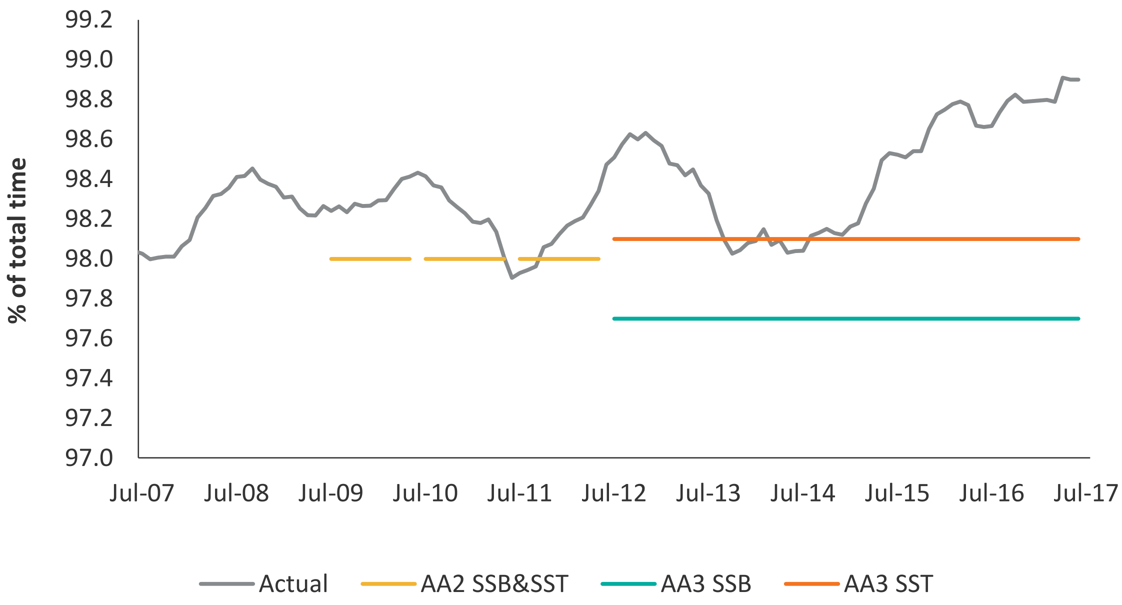
217. On the whole, transmission reliability during the AA3 period has been good. We have also introduced improvements to our planned outages scheduling process, which should help reduce average outage duration.

218. Detailed commentary on loss of event supply frequency, system minutes interrupted and average outage duration performance during the AA3 period, is provided in Western Power's 2012/13 to 2016/17 annual Service Standard Performance Reports, available on the ERA's website.

5.3.3 Security of electricity supply

219. Security of electricity supply is measured by the percentage of time that transmission circuits are available. The likelihood of an interruption on the transmission network increases when circuits are not available. During the AA3 period, circuit availability was higher than during the AA2 period (see Figure 5.19). Note a higher number represents an improvement in service for this measure.

Figure 5.19: Transmission network security, circuit availability

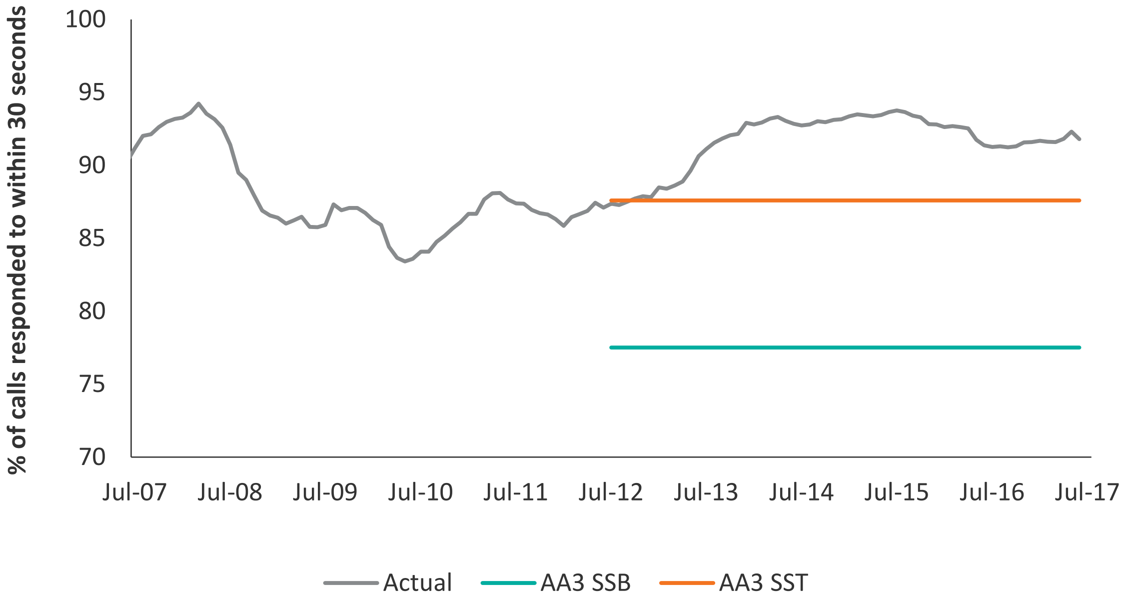


220. Circuit availability is directly related to the capital works program. The larger the capital works program, the more planned outages of transmission circuits are required to deliver the work and the lower the circuit availability. During the AA3 period, the transmission capital works program was considerably lower than forecast, primarily due to the flattening of demand growth and with it a reduced need for capacity expansion. Western Power also commenced its whole of business efficiency review and subsequent Business Transformation Project, which meant a number of proposed work programs were either re-scoped or deferred, therefore overall circuit availability was high.

5.3.4 Call centre

221. Western Power's call centre performance has improved throughout the AA3 period. We receive approximately two million calls from customers per annum with 90 per cent or more of these calls responded to within 30 seconds. Figure 5.20 shows our call centre performance over the AA3 period. Note a higher number represents an improvement in service for this measure.

Figure 5.20: Call centre, percentage of calls responded in <30 seconds



222. Wester Power's ability to respond to customer calls has been enhanced during the AA3 period due to greater use of communication channels, such as social media and the Western Power website. Our aim is to offer customers better access to online channels, increasing our level of customer interaction (and therefore timely reporting of faults) while reducing the number of telephone calls we receive.

5.3.5 Street light repair times

223. Street light repair times were fairly stable during the AA3 period and were an improvement on prior access arrangement periods. Western Power is required to repair any faulty street light within five days (on average) of the fault being reported/detected in the metropolitan area and within nine days (on average) in remote and rural towns.

224. Figure 5.21 and Figure 5.22 show our street light repair time performance over the AA3 period. Note a lower number represents an improvement in service for these measures.

Figure 5.21: Street lights, metropolitan repair times

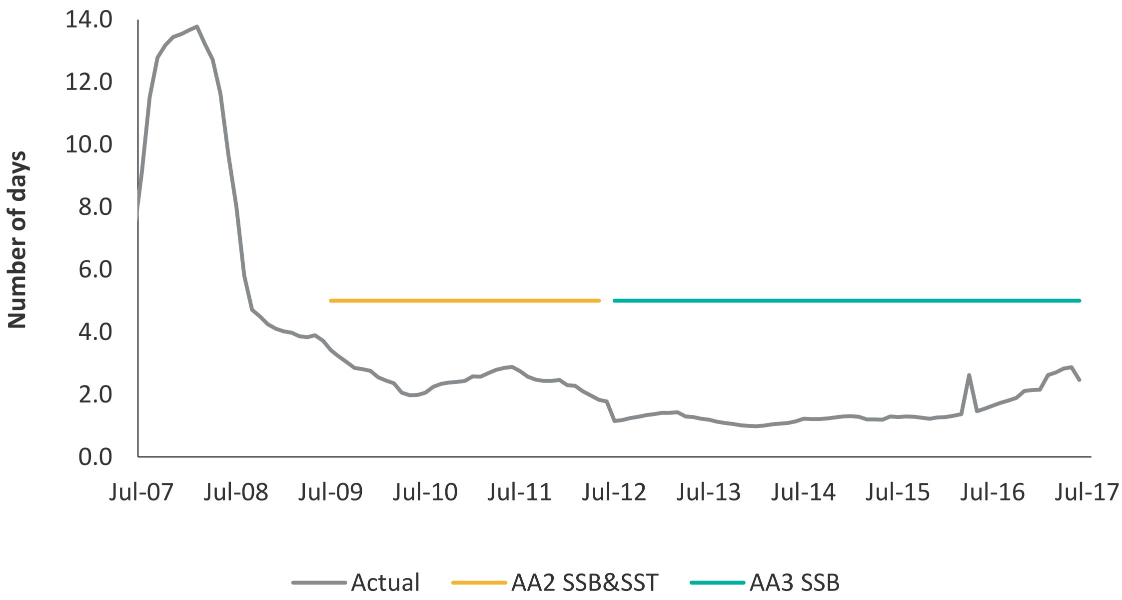
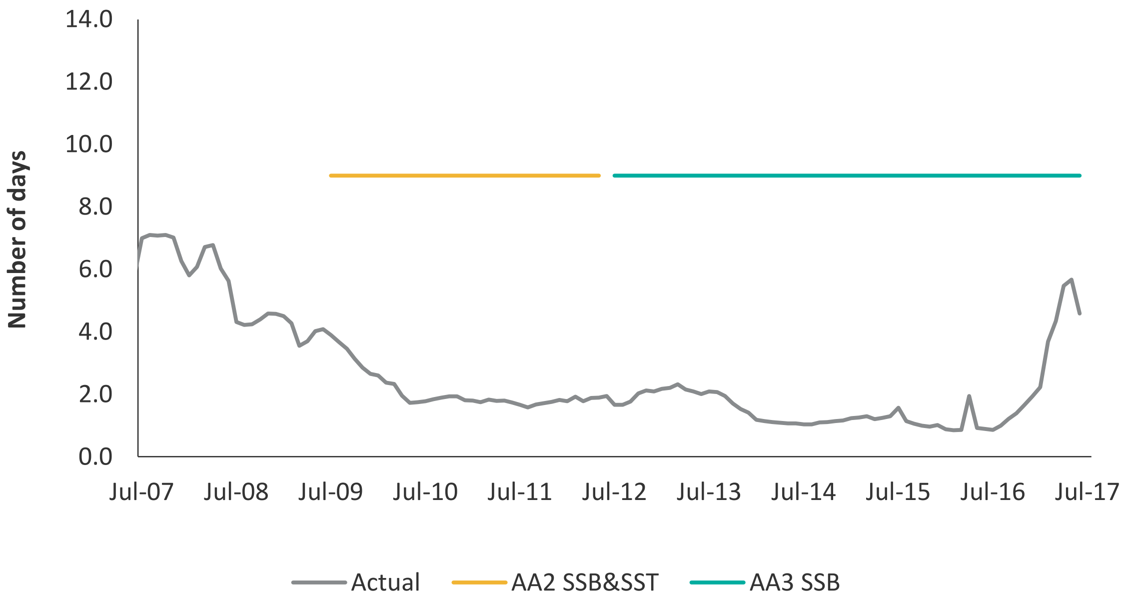


Figure 5.22: Street lights, regional repair times



225. Street light repair times have been very good throughout the AA3 period, far exceeding the SSB[52]. This is a result of the proactive street light globe replacement program, which commenced during the AA2 period, and continued until 2014/15. As part of Western Power's business review, in 2015/16 the street light repair approach was re-evaluated and changed to a predominantly reactive replacement approach managed by

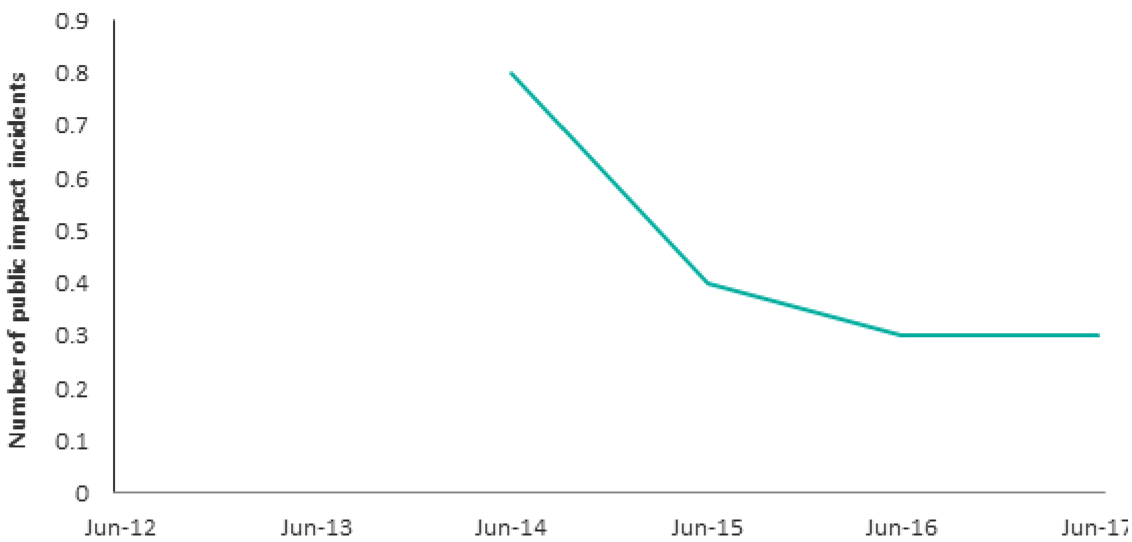
[52] Note street light repair times do not feature in the SSAM and therefore have no financial rewards and penalties attributed to performance.

Western Power internal crews rather than external contractors. This change has helped reduce street light repair costs, while still remaining well within the SSB.

5.3.6 Safety performance

226. Safety performance has improved throughout the AA3 period. Public impact incidents[53] reduced from an average of 0.8 per month in 2012/13 to 0.3 per month in 2016/17 (see Figure 5.23).[54]

Figure 5.23: Public impact incidents



227. We introduced the public impact incidents measure in 2015/16 as part of our continually improving risk-based asset management approach.[55] The measure allows us to identify incidents that have resulted in a major consequence, and direct investment in areas that will mitigate these incidents and provide a greater benefit to the community.

228. Our key safety programs of pole management, conductor management, bushfire management and connection management have seen significant investment in the treatment of wood poles and the replacement of overhead distribution conductors in high population or high fire risks zones where the consequence of failure was considered significant.

229. Our total recordable injury frequency rate (**TRIFR**) also improved over the AA3 period, falling from 9.8 at the end of the AA2 period to 3.2 in 2016/17 (see Figure 5.24).

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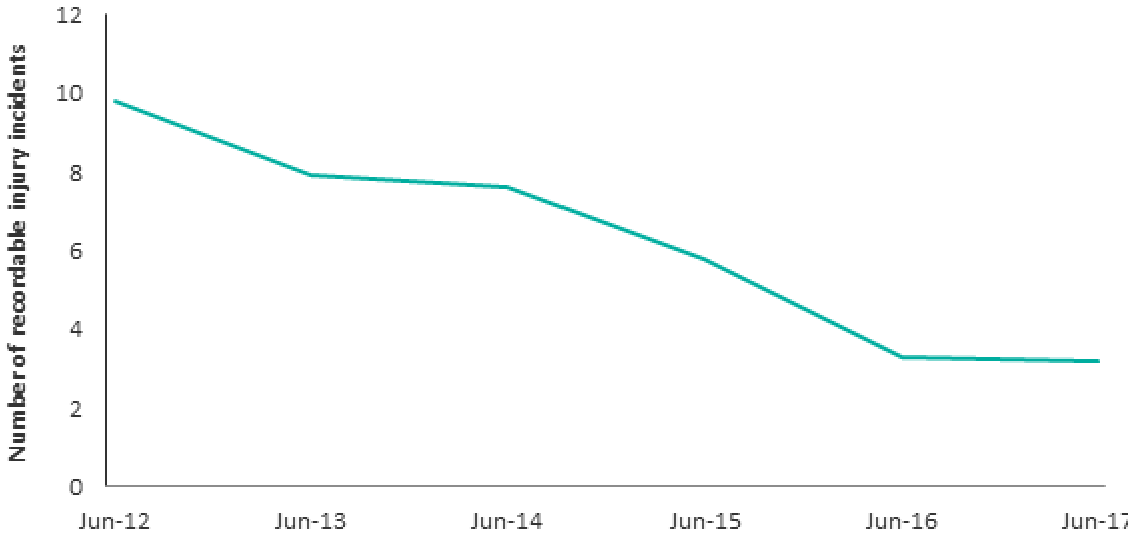
53 The public impact KPI is a 12 month rolling average of the number of incidents per month that have resulted in $20,000 damage to public property or public injury (requiring medical treatment), where the underlying cause of the incident is attributed to network assets, workforce actions or third party actions, where the network was found to be substandard.

54 The public impact KPI was introduced in 2015/16, with data calculated retrospectively for the two years prior. Insufficient data is available for 2012/13 provide a reliable comparison.

55 Previously, Western Power reported a 'public safety incidents' measure, which recorded all public safety incidents but did not capture the value of damage or severity of harm caused by the incident. The new public impact KPI is designed to capture actual loss to the public, and helps to quantify the risk associated with incidents and network assets.

Figure 5.24: Total recordable injury frequency rate



230. In 2016, we introduced a Step Change Performance Improvement Strategy to ensure health and safety is embedded in our leadership, cultural behaviour and business processes. All business leaders and supervisors took part in a *Leading the Way in Safety* program, identifying actions to improve safety performance including a renewed focus on reporting hazards. This has driven the improving trend in safety performance over the AA3 period and included the following key initiatives:

- Golden Safety Rules – a set of critical controls targeting nine high risk activities specific to our business, aimed at preventing significant incidents
- Workplace Risk Assessment Plans – task specific plans used to identify hazards and put controls in place for high risk activities
- Driver Risk Management System – a framework to manage one of our highest risk activities by understanding driving behaviours and giving our people the tools and knowledge to become safer drivers.

6. Services, incentive schemes and adjustment mechanisms

231. This chapter provides an overview of Western Power's service standards proposed for AA4. It explains the changes Western Power proposes for the AA4 period, which are designed to align the incentives with the service our customers value.

232. This chapter lists the reference services to be delivered by Western Power, and the energy demand and customer number forecasts that underpin the forecast costs of providing those services.

6.1 Overview of services and incentives proposal

233. Western Power proposes to retain the same reference services as provided during the AA3 period, with the addition of four new reference services. These are listed below.

- **D1** - Time of use energy (residential) service
- **D2** - Time of use energy (business) service
- **D3** - Time of use demand (residential) service
- **D4** - Time of use demand (business) service.

234. These new services are designed to give customers greater control over their electricity bills, and also help Western Power mitigate the need for costly capital investment to address the peak demand on the network. The tariffs associated with these new services are discussed in Chapter 11.

235. The service standard framework establishes a minimum average level of service that customers should expect from a network business providing reference services. The framework also includes an incentive regime designed to promote cost efficiencies, without compromising the level of service, through financial rewards and penalties.

236. The measure of a business's service levels is typically determined in relation to:

- reliability of supply – the frequency and duration of network interruptions and provision of services (e.g. street lighting) experienced by customers
- security of supply – the ability of the network to withstand events without interrupting supply to customers
- quality of supply – the characteristics of the supply including such things as voltage changes and harmonic distortions
- customer service – how well the business engages with customers in relation to the non-technical services including, for example, call centre performance, notification of planned outages and timely street light repairs.

237. Western Power has used customer insights to inform service level targets for the AA4 period. During the customer engagement program conducted during 2015 and 2016, customers told us they are generally satisfied with the overall service levels but believe a reliable source of electricity is essential for all customers, therefore we should focus investment on addressing localised reliability issues. They do not necessarily want Western Power to spend more money to improve network-wide reliability.

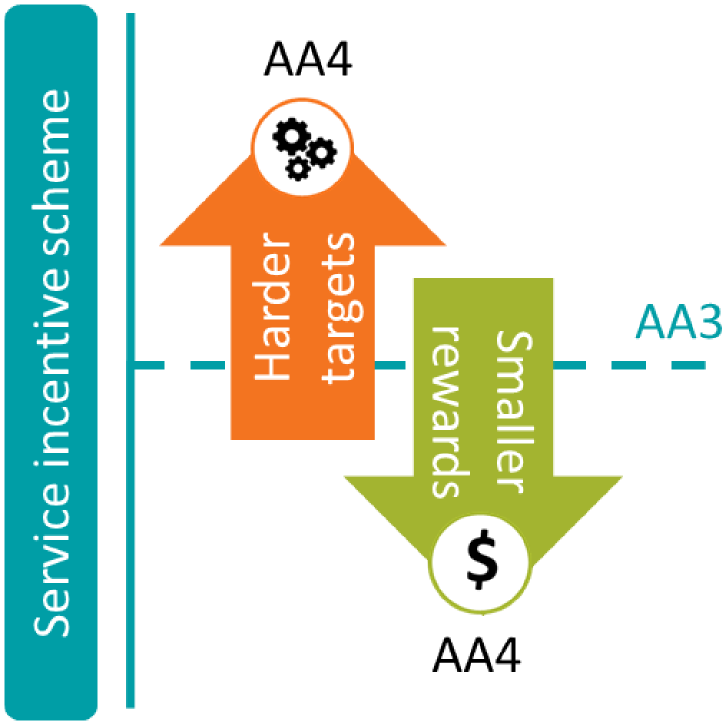
238. Therefore, the service incentive framework proposed for the AA4 period is designed to consolidate the improvements made over the past five years, and maintain overall performance at the levels achieved at the end of the AA3 period. Some pockets of the network do experience poorer service than others,

particularly at the edge of the grid, therefore we will target investment to improve performance in those areas. However, our proposal is that the service incentive framework be designed to provide an incentive for Western Power to keep overall performance at current levels.

239. In most cases the targets in the service incentive framework for the AA4 period will be set at higher standards than during AA3, and will therefore be harder to achieve. This is because performance against many of the service measures improved over the course of the AA3 period, meaning today's standards are higher than those set in 2012.

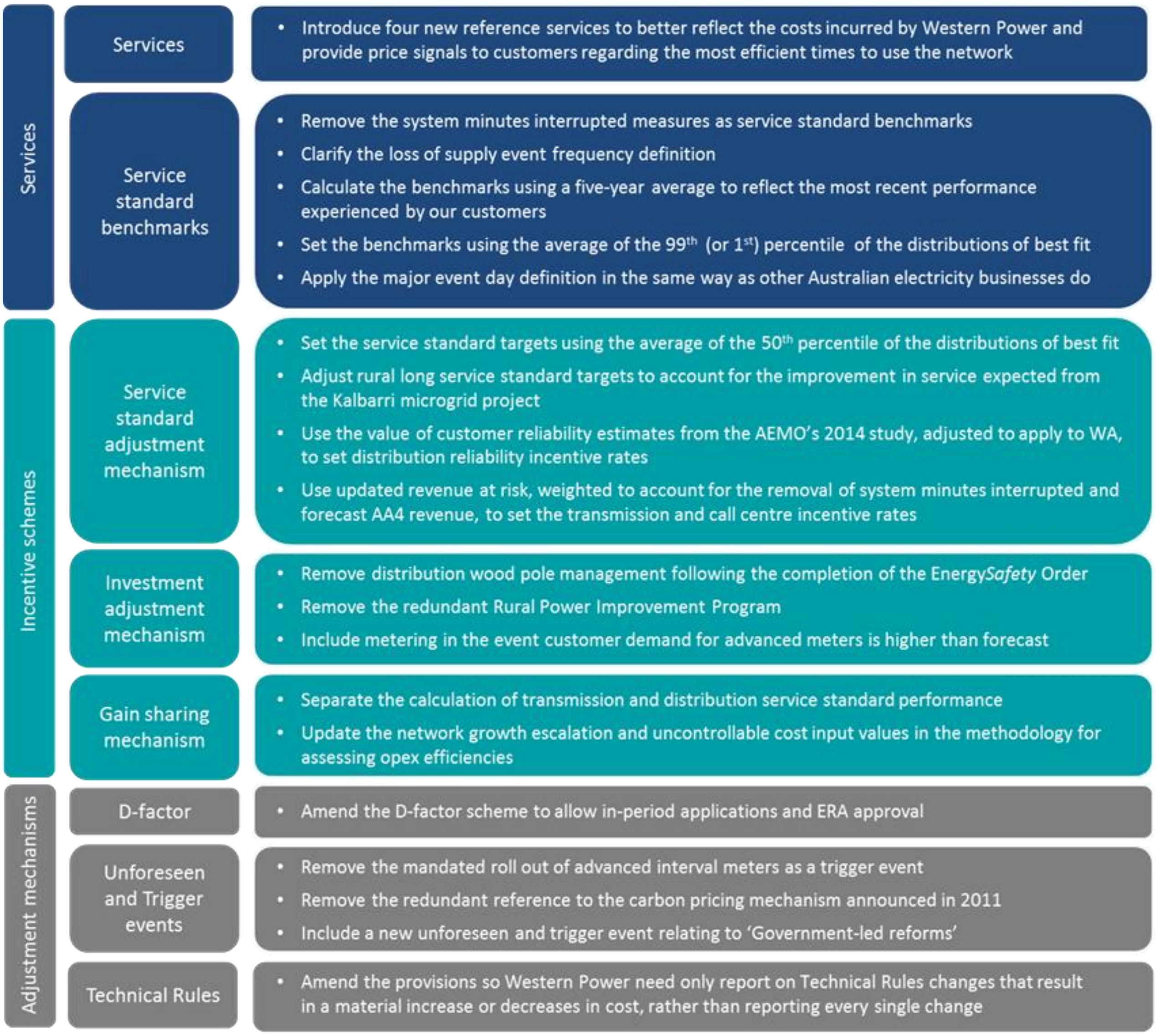
240. We propose the size of the rewards available to the business will be smaller during the AA4 period. This, in combination with the harder targets, means Western Power has a strong incentive to maintain performance at current levels, and not specifically invest to raise performance and receive gains for improvements our customers have told us they do not consider necessary.

Figure 6.1: Transition to AA4



241. In summary, we propose to retain the same services, incentives and adjustment mechanisms framework that applied during the AA3 period, with the modifications listed in Figure 6.2.

Figure 6.2: Summary of the proposed changes to the services, incentive schemes and adjustment mechanisms framework for the AA4 period



242. All other aspects of these incentive and adjustment mechanisms will remain unchanged from the AA3 period. The reason and justification for the proposed amendments are discussed in the following sections.

243. Western Power's service standard performance in the AA3 period is discussed in Chapter 5, and the associated adjustments to target revenue are provided in Chapter 10.

6.2 Regulatory framework

6.2.1 Services – regulatory requirements

244. 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.

245. 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.*

246. A non-reference service is defined as: a covered service that is not a reference service.

247. 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.

248. The ERA has not declared any services as excluded services under sections 6.33 to 6.37 of the Access Code. Further, Western Power does not propose to provide, or seek to have the ERA determine, any service as an excluded service in AA4.

249. Sections 5.1 and 5.2 of the Access Code require Western Power to include in our access arrangement one or more reference services that apply as follows:

5.1 An access arrangement must:

(a) specify one or more reference services under section 5.2

5.2 An access arrangement must:

(a) specify at least one reference service; and

(b) specify a reference service for each covered service that is likely to be sought by either or both of:

(i) a significant number of users and applicants; or

(ii) a substantial proportion of the market for services in the covered network;

and

(c) to the extent reasonably practicable, specify reference services in such a manner that a user or applicant is able to acquire by way of one or more reference services only those elements of a covered service that the user or applicant wishes to acquire; and

(d) for the Western Power Network — specify one or more reference services such that there is both:

(i) a reference service which enables a user or applicant to acquire an entry service at a connection point without a need to acquire a corresponding exit service at another connection point; and

(ii) a reference service which enables a user or applicant to acquire an exit service at a connection point without a need to acquire a corresponding entry service at another connection point.

6.2.2 Minimum service standards – regulatory requirements

250. The Access Code requires Western Power to include in its access arrangement SSBs as follows:

> *5.1 An access arrangement must:*
>
> *…*
>
> *(c) include service standard benchmarks under section 5.6 for each reference service;*
>
> *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.*

251. Western Power must provide services to its customers that at least meet the SSBs in accordance with section 11.1 of the Access Code, and report its performance against the SSBs to the ERA annually.

> *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.*
>
> *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.*

6.2.3 Service standard adjustment mechanism – regulatory requirements

252. Section 6.30 of the Access Code requires Western Power's access arrangement to contain a SSAM. Sections 6.29 to 6.31 of the Access Code provides the following in relation to the SSAM:

> *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.*
>
> *6.30 An access arrangement must contain a service standards adjustment mechanism.*
>
> *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.*

6.2.4 Gain sharing mechanism – regulatory requirements

253. Under section 6.20 of the Access Code, Western Power's access arrangement is required to contain a GSM as follows:

> *6.19 A "gain sharing mechanism" is a mechanism:*
>
> *(a) in an access arrangement which the Authority must apply 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; and*
>
> *(b) which operates as set out in sections 6.20 to 6.28.*
>
> *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).*

254. Section 6.21 of the Access Code sets out the objective of the GSM as:

> *(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.*

255. The efficiency and innovation benchmarks that are used to determine the above-benchmark surplus, and therefore any rewards under the gain sharing mechanism, are covered under sections 5.25 and 5.26 of the Access Code as follows:

> *5.25 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.*
>
> *5.26 Efficiency and innovation benchmarks must:*
>
> *(a) if the access arrangement contains a gain sharing mechanism, be sufficiently detailed and complete to permit the Authority to make a determination under section 6.25 at the next access arrangement review; and*
>
> *(b) provide an objective standard for assessing the service provider's efficiency and innovation during the access arrangement period; and*
>
> *(c) be reasonable.*
>
> *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.*

6.2.5 Investment adjustment mechanism – regulatory requirements

256. Section 6.15 of the Access Code requires Western Power to include an investment adjustment mechanism (**IAM**), which adjusts revenue in future access arrangement periods for differences between forecast and actual capex.

6.15 If an access arrangement uses the form of price control described in section 6.2(a), then the access arrangement must contain an investment adjustment mechanism.

257. Sections 6.16 to 6.18 of the Access Code provide further details in relation to the IAM.

6.16 Without limiting the types of investment adjustment mechanism which may be contained in an access arrangement, an investment adjustment mechanism may provide that:

(a) adjustments are to be made to the target revenue for the next access arrangement in respect of the full extent of any investment difference; or

(b) no adjustment is to be made to the target revenue for the next access arrangement in respect of any investment difference.

6.17 An investment adjustment mechanism must be:

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

(b) without limiting this Code, consistent with the gain sharing mechanism (if any) in the access arrangement;

(c) consistent with the Code objective.

6.18 An investment adjustment mechanism in an access arrangement applies at the next access arrangement review.

6.2.6 Unforeseen events – regulatory requirements

258. Section 6.6 of the Access Code provides that costs incurred during an access arrangement period as the result of an unforeseen event can be recovered via an adjustment to target revenue in the next period.

6.6 If:

(a) during the previous access arrangement period, a service provider incurred capital-related costs or non-capital costs as a result of a force majeure event; and

(b) the service provider was unable to, or is unlikely to be able to, recover some or all of the costs ("unrecovered costs") under its insurance policies; and

(c) at the time of the force majeure event the service provider had insurance to the standard of a reasonable and prudent person (as to the insurers and the type and level of insurance),

then subject to section 6.8 an amount may be added to the target revenue for the covered network for the next access arrangement period in respect of the unrecovered costs.

6.7 Nothing in section 6.6 requires the amount added under section 6.6 in respect of unrecovered costs to be equal to the amount of unrecovered costs.

6.8 An amount must not be added under section 6.6 in respect of capital-related costs or non-capital costs, to the extent that they exceed the costs which would have been incurred by a service provider efficiently minimising costs.

6.2.7 Trigger events – regulatory requirements

259. Section 5.34 of the Access Code provides that an access arrangement can list a number of trigger events that allow the access arrangement to be re-opened. These may be events that would result in Western Power incurring materially higher or lower costs as a result of an event that has the potential to occur during the access arrangement period (for example energy sector reforms or a carbon tax).

> *5.34 If it is consistent with the Code objective an access arrangement may specify one or more trigger events.*
>
> *5.35 To avoid doubt, under section 5.34, an access arrangement may specify a trigger event which was not proposed by the service provider.*
>
> *5.36 Before determining whether a trigger event is consistent with the Code objective the Authority must consider:*
>
> *(a) whether the advantages of including the trigger event outweigh the disadvantages of doing so, in particular the disadvantages associated with decreased regulatory certainty; and*
>
> *(b) whether the trigger event should be balanced by one or more other trigger events.*

6.2.8 Technical Rules changes – regulatory requirements

260. Section 6.9 of the Access Code provides that revenue in the next period can be adjusted for unforeseen costs relating to changes to the Technical Rules.

> *6.9 If, during the previous access arrangement period, the technical rules for the covered network were amended under section 12.53 with the result that the service provider, in complying with the amended technical rules:*
>
> *(a) incurred capital-related costs or non-capital costs:*
>
> *(i) for which no allowance was made in the access arrangement; and*
>
> *(ii) which the service provider could not have reasonably foreseen at the time of the approval of the previous access arrangement;*
>
> *and*
>
> *(b) did not incur capital-related costs or non-capital costs for which allowance was made in the access arrangement,*
>
> *then subject to sections 6.10 to 6.12 an amount may be added to the target revenue for the covered network for the next access arrangement period in respect of the costs.*
>
> *6.10 The amount (if any) to be added under section 6.9(a) must be positive, and the amount (if any) to be added under section 6.9(b) must be negative.*
>
> *6.11 A positive amount must not be added under section 6.9(a) in respect of capital-related costs or non-capital costs, to the extent that they exceed the costs which would have been incurred by a service provider efficiently minimising costs.*
>
> *6.12 A negative amount added under section 6.9(b) must have regard to the savings that would have been made by a service provider efficiently minimising costs even if the service provider did not actually achieve that level of savings.*

6.3 Services

6.3.1 Reference services

261. Western Power proposes to retain the current 17 reference services provided in AA3 as they continue to accurately reflect our service offerings in AA4. Services are categorised as either:

- **Distribution services** – the majority of our customers are connected to the distribution network and receive a distribution reference service. Their reference service is influenced by the performance of, and forecast expenditure in both the distribution and transmission network. The revenue is therefore recovered from both transmission and distribution customers.
- **Transmission services** – a small number of large customers and generators are connected directly to the transmission network and receive a transmission reference service. Their reference service is influenced by the performance of, and expenditure in the transmission network only and the revenue is therefore only recovered from transmission customers.
- **Street light services** – we operate, maintain and provide network access for street lights in the SWIS. The revenue is recovered from distribution and transmission customers.

262. Western Power's change to advanced meters as the standard meter (see Chapter 8) enables new services to be introduced which give customers greater control over their electricity bills, and also help Western Power mitigate the need for costly capital investment to address the peak demand on the network. We propose to introduce four new reference services that are enables by advanced meters:

- **D1** - Time of use energy (residential) service
- **D2** - Time of use energy (business) service
- **D3** - Time of use demand (residential) service
- **D4** - Time of use demand (business) service.

263. These services will be provided to all residential and small business customers requesting[56] a new meter as advanced meters will now be installed as standard. The new tariffs that correspond to these new services better reflect the costs incurred by Western Power in providing reference services and will provide price signals to customers regarding the most efficient times to use the network.

264. Western Power has consulted with customers, retailers and the State Government to develop these services. These new time of use reference services will provide customers with the best opportunity to manage their own consumption in an efficient and cost effective manner. Our aim is to encourage customers to change their consumption patterns (where practicable) by shifting their electricity use to off-peak times. This would potentially decrease their electricity bills and also allow Western Power to reduce investment in the network to accommodate peak demand. The rationale and impact of time of use tariffs is discussed further in Chapter 11.

265. Table 6.1 provides a full list of reference services that we propose to offer customers in AA4.

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56 Where Western Power installs an advanced meter for compliance reasons, customer may choose to opt-in to these new services.

Table 6.1: AA4 reference services

Service	Description	Category	Revenue cap recovery Tx = transmission Dx = distribution
A1	Anytime energy (residential) exit service	Distribution	Tx and dx
A2	Anytime energy (business) exit service	Distribution	Tx and dx
A3	Time of use energy (residential) exit service	Distribution	Tx and dx
A4	Time of use energy (business) exit service	Distribution	Tx and dx
A5	High voltage metered demand exit service	Distribution	Tx and dx
A6	Low voltage metered demand exit service	Distribution	Tx and dx
A7	High voltage contract maximum demand exit service	Distribution	Tx and dx
A8	Low voltage contract maximum demand exit service	Distribution	Tx and dx
A9	Street lighting exit service	Street lights	Tx and dx (incl. street light operating and maintenance costs)
A10	Unmetered supplies exit service	Distribution	Tx and dx
A11	Transmission exit service	Transmission	Tx
B1	Distribution entry service	Distribution	Tx and dx
B2	Transmission entry service	Transmission	Tx
C1	Anytime energy (residential) bi-directional service	Distribution	Tx and dx
C2	Anytime energy (business) bi-directional service	Distribution	Tx and dx
C3	Time of use (residential) bi-directional service	Distribution	Tx and dx
C4	Time of use (business) bi-directional service	Distribution	Tx and dx
D1	Time of use energy (residential) service	Distribution	Tx and dx
D2	Time of use energy (business) service	Distribution	Tx and dx
D3	Time of use demand (residential) service	Distribution	Tx and dx
D4	Time of use demand (business) service	Distribution	Tx and dx

266. Further information on each of these reference services is provided in Chapters 8 and 11.

6.3.2 Non-reference services

267. Where a customer requests Western Power to provide non-standard services, we can develop a customised product as a non-reference service. Examples of non-reference services currently provided by Western Power include:

- processing and administration fees associated with an application for network access as detailed in the AQP
- network access services with conditions that vary from reference services, including:
  - transmission connected customers that have agreed to accept an interruptible service to avoid paying the cost prohibitive deep connection costs that would otherwise be required to provide a standard service
  - customers with additional network redundancy or back-up supply available where they have paid for increased security and reliability for their connection
  - connections for which the customer's equipment does not meet the Technical Rules, but for which Western Power has sought an exemption from the ERA, and Western Power is required to provide additional services
- all other services that are not core to the transport of electricity from the supplier to the end-use customer, including, for example the elevation of overhead lines to allow the transport of high loads and the provision of pre-payment metering services.

268. The specifics of the non-standard service and corresponding tariff provided by Western Power is negotiated with the customer following a request for a non-standard service. The non-standard services we provide under non-reference service contracts are not listed or priced, other than in the contract. Further, as these services are customers, they do not have minimum service standards provided.

6.4 Reporting on the level of service provided to our customers

269. Western Power monitors and reports on a comprehensive range of performance measures. Almost 200 of these performance measures relate to service standards. The reporting framework is prescribed by a range of legal instruments, including the access arrangement.

270. Legislative obligations relating to service performance include those contained in the *Code of Conduct for the Supply of Electricity for Small Use Customers 2008*, *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* (**NQRS Code**) and Standing Committee on National Regulatory Reporting Requirements.

271. Through AA4 we will continue to report publicly on our service performance via the following channels:

- **quarterly reports** – providing an overview of our performance during the quarter against the key performance indicators that are in our Statement of Corporate Intent[57] which includes safety, reliability and financial measures
- **annual service standard performance reports** – providing an overview of our performance against the service standard benchmarks and targets in our access arrangement

57 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.

- **annual reliability and power quality reports** – providing information required as part of Schedule 1 of the NQRS Code.

272. The ERA also independently reviews and reports on our service performance in its *Annual Performance Report - Energy Distributors*, in accordance with its administration of the electricity licence scheme under Part 2 of the *Electricity Licence Act 2004*. The *2017 Electricity Distribution Licence Performance Reporting Handbook* details the performance indicators that Western Power is required to report annually.

6.5 Determining appropriate service performance measures

273. The access arrangement details each of the specific **minimum service standards** Western Power must meet during that access arrangement period. Under section 5.1 of the Access Code, Western Power is required to have SSBs for each of its reference services[58]. These SSBs are our minimum service standards.

274. For each reference service, we have proposed measures that are meaningful and will ensure our customers receive at least a minimum level of service in relation to security, reliability and quality of supply as well as customer service. SSBs for the AA4 period cover reliability and security of supply for our transmission and distribution network, timely repair of street lights, and call centre performance. Quality of supply is measured under the *Network Quality and Reliability of Supply Code 2005* and reported in Western Power's annual Reliability and Power Quality Report.

275. Western Power proposes 15 measures for which there are SSBs across the transmission and distribution network and for street lights for the AA4 period. The proposed SSBs are summarised in Figure 6.3.

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58 Western Power has a number of different measures that apply to each of its transmission and distribution reference services. The measures do not have a direct relationship with a single service and vice versa. The access arrangement specifies which measures apply to each reference service.

Figure 6.3: AA4 proposed service standard benchmarks

	Transmission	Distribution	Street lights
Frequency	**Loss of supply event frequency** – the frequency of unplanned customer interruption event where the loss of supply is either: • >0.1 and ≤1 system minutes interrupted • >1 system minutes interrupted	**System Average Interruption Frequency Index (SAIFI)** – the average number of times a customer's electricity is interrupted each year for longer than one minute, attributable solely to the distribution network. It is measured separately for: • CBD • urban • rural short • rural long	
Duration	**Average outage duration** – the average duration of all unplanned outages on the transmission network	**System Average Interruption Duration Index (SAIDI)** – the total number of minutes on average that a customer on the distribution network is without electricity each year for longer than one minute, attributable solely to the distribution network. It is measured separately for: • CBD • urban • rural short • rural long	**Street light repair time** – the average number of business days taken to repair a faulty streetlight. It is measured separately for: • metropolitan area • regional area
Security of supply	**Circuit availability** – the percentage of time the transmission network circuits are available		
Customer service		**Call centre performance** – the percentage of fault calls responded to in ≤30 seconds	

276. We propose to retain the majority of measures from AA3 for which there are SSBs as we consider they appropriately measure the average level of service Western Power provides to its customers. However, we propose to remove the following two transmission measures as SSBs:

- radial system minutes interrupted
- meshed system minutes interrupted.

277. We also propose to correct the definition of loss of supply event frequency greater than 0.1 system minute to align with the intended application of between 0.1 and less than or equal to one system minute interrupted.

278. These points are discussed in the following sections.

6.5.1 Removal of system minutes interrupted measures as SSBs

279. Western Power proposes to remove the system minutes interrupted – radial and meshed network measures as SSBs for the AA4 period. We consider these measures do not provide meaningful information and do not accurately represent the service performance experienced by our customers. Moreover, transmission network performance is already covered by other transmission measures, meaning the system

minutes interrupted measures can be removed from the service incentive framework without increasing the risk that customers will experience a deterioration in performance. Therefore we consider there is little value in retaining these measures during the AA4 period.

280. Our concerns with the system minutes interrupted measures are discussed in more detail below.

6.5.1.1 The system minutes interrupted SSBs measure overall network performance rather than the performance in relation to transmission reference services

281. Sections 5.1 and 5.6 of the Access Code require SSBs to be specified for each reference service, to determine the value represented by the reference service at the reference tariff.

282. The system minutes interrupted SSBs measure the system-wide performance of the transmission network. That is, they measure the level of performance provided to reference service customers and non-reference service customers, in aggregate. They do not reflect the level of service provided specifically to reference service customers. We therefore consider the system minutes interrupted measures do not meet the definition of a SSB and should be removed.

6.5.1.2 The system minutes interrupted SSBs are not considered to be statistically sound

283. When considering suitable performance measures for transmission network service providers, the Australian Competition and Consumer Commission (**ACCC**) expressed the view that the system minutes interrupted measure is statistically unsound in terms of describing the underlying performance of transmission networks.[59] Consequently in 2003, it was replaced under the national transmission Service Target Performance Incentive Scheme (**STPIS**) with the loss of supply event frequency measure.

284. In its AA3 final decision, the ERA stated it accepted that the System Minutes Interrupted measure has some less than desirable statistical characteristics.[60]

285. We do not consider that the system minutes interrupted SSBs are statistically sound and therefore do not provide a reliable representation of transmission services.

6.5.1.3 The performance of the transmission network is already accounted for in other transmission SSBs

286. Radial and meshed system minutes interrupted are two of the six measures in the current suite of transmission SSBs. We consider the remaining four transmission SSBs (loss of supply event frequency >0.1 and >1 system minute, average outage duration and circuit availability) adequately measure the level of service provided to our transmission connected reference service customers.

287. In its AA3 final decision, the ERA agreed “the Loss of Supply Event Frequency and Average Outage Duration measures together can provide an equivalent performance measure to System Minutes Interrupted.”[61]

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59 Page 5, *Transmission Network Service Provider (TNSP) – Service Standards, Final Report, Report prepared for the Australian Competition and Consumer Commission (ACCC)*, SKM, March 2003.

60 Page 440, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 5 September 2012.

61 Page 441, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 5 September 2012.

288. We therefore consider that the value of transmission services is appropriately represented by the other four transmission SSBs.

6.5.1.4 *The majority of transmission customers connected to the radial network are under non-reference service contracts*

289. In its AA3 final decision, the ERA required Western Power to retain the system minutes interrupted radial measure in particular, noting that it was *concerned to ensure that there are incentives to maintain radial networks performance, as these networks – unlike meshed networks – do not have redundancy*.[62] Western Power currently has an estimated 28 transmission connected customer loads[63], 14 of which are connected to radial networks with limited redundancy. Seven of these 14 customers have agreed to Western Power providing a non-reference service, at a lower than standard level of service, to avoid the significant deep network connection costs they would otherwise have had to pay to receive a reference service in rural areas of the network. That is, there are currently only three customers that are supplied by radial transmission network and receive a reference service.

290. Moreover, given the recent EMR and general discussion in the WA energy sector[64], it is reasonable to assume a fully constrained network and market solution will be introduced in the near future. This would see a decline in the number of transmission customers that receive reference services when connected to radial networks. As a result, not only is the measure not particularly meaningful, it will only apply to a very small number of customers.

291. Western Power also considers the retention of radial system minutes interrupted measure as an SSB provides a perverse incentive to make significant investments in the transmission radial network where customers do not value it.[65]

292. A more efficient and effective way to address the ERA's concern that these three customers do not receive the level of service required is for us to closely measure the relationship with these customers.

6.5.2 Clarification of loss of supply event frequency measures

293. For AA3, Western Power set its loss of supply event frequency performance measures based on historical data for:

- loss of supply events greater than 0.1 and equal to or less than one system minute
- loss of supply events greater than one system minute.[66]

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62 Page 441, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 5 September 2012.

63 Customers (rather than connection points) with major loads and generation facilities being provided with transmission exit services.

64 The Minister for Energy announced at the '2017 Energy in WA Conference' that he intended to move from an unconstrained to a constrained access regime. He stated his intention was to introduce legislative amendments to Parliament by mid-2018 for changes to be implemented by 2020.

65 If customers valued the unconstrained access they would be willing to pay for the deep network augmentation costs and would not have agreed to a lower level of service.

66 Page 49, *Access Arrangement Information for 1 July 2012 to 30 June 2017,* Western Power, September 2011.

294. This ensured that the two measures were discrete and did not duplicate the compliance and financial incentives for those events that were between 0.1 and one system minute.

295. Additionally, they reflected two distinct types of events that occur on the transmission network -small events[67] that result in a loss of supply frequency for 0.1 up to and including one system minute, and large events[68] that result in a loss of supply frequency for more than one system minute. The use of two discrete loss of supply event frequency measures is consistent across Australia, with the intention to "encourage transmission network service providers to reduce the duration of moderate and small customer interruptions through improved reliability."[69]

296. Section 4.3.6 of the current access arrangement states that loss of supply event frequency is applied as follows:

> *Over a 12 month period, the frequency of unplanned customer outage events where loss of supply:*
>
> - *Exceeds 0.1 system minutes interrupted and*
> - *Exceeds 1.0 system minutes interrupted.*[70]

297. For AA4 we propose to clarify that the two loss of supply event frequency measures are independent, do not overlap and reflect different types of events. This will ensure that we do not double-count those events greater than one system minute, and maintains focus on both types of events that cause a loss of system frequency. To do this we have proposed to amend the access arrangement to specify that loss of supply event frequency >0.1 relates to those events where that loss of supply exceeds 0.1 system minute interrupted **and** is equal to or less than one system minutes interrupted.

6.6 Setting the minimum service standards for AA4

298. When defining the measures and setting targets, we have considered insights from our customer engagement program (discussed in Chapter 4). Customers have told us they are generally satisfied with current levels of performance, and do not necessarily want Western Power to invest to improve service. Though there are areas of the network that perform more poorly than others, and Western Power will target improvement in these areas, there is little appetite among customers for Western Power to invest more to raise overall service levels.

299. During our customer engagement, around three quarters of our customers said:

> The duration of the outages we experience are about right.

300. A larger proportion of customers (86 per cent) said:

> The number of outages we experience is 'reasonable' or better than we would consider acceptable.

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67 Small loads interrupted for short periods.

68 Large loads interrupted for a short duration, or a moderate load interrupted for a long duration.

69 Page 5, *Final decision – electricity transmission service target performance incentive scheme version 5*, AER, 17 September 2015.

70 Page 18, *Amended proposed revisions to the Access Arrangement for the Western Power Network*, Western Power, June 2015.

301. Taking these customer insights and our regulatory obligations into consideration, we propose to maintain the current average level of service provided to reference service customers during AA4.

6.6.1 Service standard benchmarks

302. Western Power proposes to retain its approach to determining its SSBs for the AA4 period, with refinements to improve the statistical accuracy of the methodology.

303. Section 5.6 of the Access Code requires our SSBs to be reasonable and 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 of the Access Code then requires Western Power to provide services to its customers in a manner that is at least equivalent to the SSBs.

304. Over the course of the AA3 period, Western Power achieved improvements in the majority of its service performance measures. To ensure that we maintain the average level of service our reference service customers have received over recent years, Western Power proposes to change its methodology for setting SSBs (except street lights) as follows:

- establishing the data series on which our SSBs are based using:
  - five years of data for measures, rather than three years for SAIDI and SAIFI and five years for all other measures
  - a Box-Cox transformation to determine the probability of a major event day, rather than a normal distribution
  - when calculating the major event day threshold, use distribution unplanned daily SAIDI, rather than daily SAIDI including all interruptions
- using the average of the 99th percentile (or 1st percentile for circuit availability and call centre performance) of the distributions of best fit to set our SSBs, rather than the 97.5th percentile (or 2.5th percentile).

305. We propose to continue to set SSBs for street lights to align with the *2017 Electricity Distribution Licence Performance Reporting Handbook*[71]*.* These requirements have not changed from AA3.

306. Using this proposed methodology, the proposed SSBs for the AA4 period are the same or more stringent for the majority of measures, reflecting the improvements in our performance in AA3. The exceptions are rural long SAIDI and SAIFI, and average outage duration. These SSBs will be set at the same level for each year because no investment in service improvement has been included in the AA4 expenditure forecast.

307. We do not expect the ERA to make a final decision on the revised proposed access arrangement until June 2018 at the earliest.

308. As a result, for 2017/18 and until the AA4 period commences we will continue to operate and invest in the business to meet the current AA3 suite of SSBs. While other aspects of the revised access arrangement such as target revenue and resulting prices will be adjusted and back dated to 1 July 2017, any revised service level benchmarks and targets can only take effect from the time the revised access arrangement is finalised. This is because Western Power would not have the opportunity to manage the network prior to and during 2017/18 to comply with unknown SSBs in 2017/18.

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71 Page 14, *2017 Electricity Distribution Licence Performance Reporting Handbook*, ERA, 2017.

309. Applying the current suite of SSBs during 2017/18 provides certainty for Western Power and our customers of the minimum service standards that apply during 2017/18. It also ensures that our AA4 forecast capex and opex (see Chapters 7 and 8) are sufficient to allow Western Power to meet those SSBs.

310. Table 6.2 shows the proposed SSBs.

Table 6.2: AA4 proposed service standard benchmarks

Performance measure	Unit	AA3	2017/18	From 2018/19
Distribution				
System average interruption duration index				
CBD	Minutes	39.9	39.9	37.2
Urban	Minutes	183.0	183.0	134.7
Rural short	Minutes	227.8	227.8	226.3
Rural long	Minutes	724.8	724.8	902.9
System average interruption frequency index				
CBD	Number of events	0.26	0.26	0.23
Urban	Number of events	2.12	2.12	1.33
Rural short	Number of events	2.61	2.61	2.38
Rural long	Number of events	4.51	4.51	5.90
Calls responded to in 30 seconds	Per cent	77.5	77.5	85.3
Transmission				
Circuit availability	Per cent	97.7	97.7	97.6
Loss of supply event frequency				
>0.1 and ≤1 system minutes	Number of events	33	33	27
>1 system minutes	Number of events	4	4	4
Average outage duration	Minutes	886	886	1333
Street lighting				
Repair times for Perth Metropolitan area	Days	5	5	5
Repair times for major regional towns	Days	9	9	9

311. Our statistical methodology and software code used to develop our SSBs and SSTs was independently reviewed by an independent expert, Analytics + Data Science. This technical review found that Western Power's distribution fitting methodology "represents an appropriate methodology for the purpose of

selecting a statistical distribution for setting SSBs and SSTs using a theoretically consistent and industry standard approach". The full review of our statistical methodology is provided in Attachment 6.1.

312. The following sections detail each of the proposed changes to setting SSBs for the AA4 period. The complete methodology is provided in Attachment 6.2.

6.6.2 Establishing the data series used to set SSBs

6.6.2.1 Determining the time period for data

313. For AA4, Western Power has calculated minimum service standards using a five-year rolling average. This is consistent with the approach applied for AA3 except for the distribution service standard performance measures which were based on three years of data. The increase in the time period used to set the distribution service standard performance measures, compared to AA3, will improve the statistical accuracy of the outcomes.

314. For the AA3 period, the ERA required Western Power to use three years of data to determine the SSBs for distribution SAIDI and SAIFI measures to reflect:

- lower quality data through the AA1 period which the ERA and Western Power agreed was not statistically robust enough to drive compliance targets
- recent improvements in performance that Western Power had achieved during the AA2 period through its targeted reliability improvement program, which the ERA considered should be more heavily weighted.

315. The remainder of Western Power's distribution measures were established using five years of data.

316. For the AA4 period, we propose to use five years of data to set all SSBs. This is because:

- Western Power has focused on maintaining service performance through a relatively stable average level of non-growth distribution capex over the last five years
- a longer data series provides more statistically correct outcomes as it provides a better estimate of the long-term variance
- a longer period captures a more even pattern of expenditure and minimises the impact of abnormal years, which may skew a shorter data set and lead to overly lenient or harsh compliance targets
- the business now has a reliable dataset covering a longer period
- five years of data aligns with the length of the access arrangement, and the period of the SSAM and GSM
- using a data series that aligns with the access arrangement (regulatory) period is consistent with the approach used to determine the equivalent of SSTs by other utilities'[72], including other Australian electricity distribution businesses.

6.6.2.2 Determining the probability of a major event day

317. The access arrangement describes the application of each of the measures and outlines certain events to be excluded. These exclusions include, for the distribution measures, events that are beyond the electricity

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72 Note that there are no SSB equivalents under the national Electricity Rules. They are in individual jurisdictional instruments similar to our *Electricity Industry (Network Quality and Reliability of Supply) Code 2005*.

distributor's control such as the effects of transmission network outages and other upstream events. They also exclude the effects of extreme weather events that have the potential to significantly affect Western Power's network performance (the major event days) unless significantly higher expenditure is forecast to enable supply to be restored more quickly if such an event occurred.

318. These major event day exclusions articulated in the access arrangement use a statistical formula to calculate a threshold value. Currently, Western Power uses the Institute of Electrical and Electronics Engineers' (**IEEE**) 2.5 beta method[73] to calculate the major event day threshold. This method sets the threshold at 2.5 standard deviations from the mean value after transforming the daily outage data into a normal distribution data stream. Where the SAIDI value of a particular day exceeds this threshold value, it is considered to be a major event day and the data from these days is excluded from the data set used for calculating the actual performance.

319. The IEEE major event days methodology is based on studies of the distribution networks of North America, which assumes the SAIDI follows a normal distribution. During the AA3 period, Western Power strictly applied this method, and used a normal distribution to determine the probability of a major event day to calculate the major event day threshold.

320. Since the AA3 submission, the Australian Energy Market Commission (**AEMC**) has reviewed the application of this method in Australia[74]. The AEMC considers it appropriate for the Australian Energy Regulator to allow network businesses to propose an alternative statistical method for calculating the threshold for major event days[75].

321. In assessing the service incentive framework, Western Power has completed statistical modelling and determined that a normal distribution is not the best fit for our SAIDI data[76]. Rather, a Box-Cox transformation is a better fit to our SAIDI data. We therefore propose to use a Box-Cox transformation to adjust the data sets using a lambda (λ) value so they follow an approximate normal distribution.

322. The Box-Cox transformation used to determine the major event day threshold is as follows:

$$X_{norm} = \frac{X^{\lambda} - 1}{\lambda} \; for \; X \neq 0, X_{norm} = \ln(X) \; for \; X = 0$$

1. The current and proposed methods of determining the major event day threshold are provided in Figure 6.4 and Figure 6.5.

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73 IEEE Standard 1366, *IEEE Guide for Electric Power Distribution Reliability Indices*.

74 Section 4, *Review of Distribution Reliability Measures, Final Report*, AEMC, 5 September 2014.

75 Section 4, *Review of Distribution Reliability Measures, Final Report*, AEMC, 5 September 2014.

76 The best fit was determined by applying the lowest overall scores from the Kolmogorov-Smirnov, Cramer-von Mises and Anderson-Darling tests. Western Power's current method was the worst fitting distribution (i.e. when the log normal method for all interruptions SAIDI was applied (λ = 0) and was ranked the worst using each of the Kolmogorov-Smirnov, Cramer von-Mises and Anderson-Darling tests).

Figure 6.4: Current normal distribution

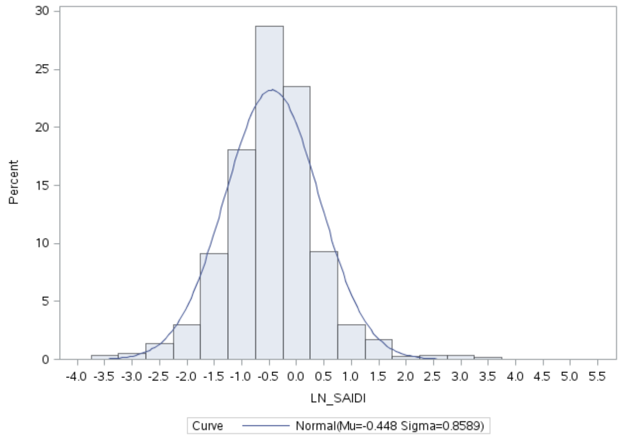
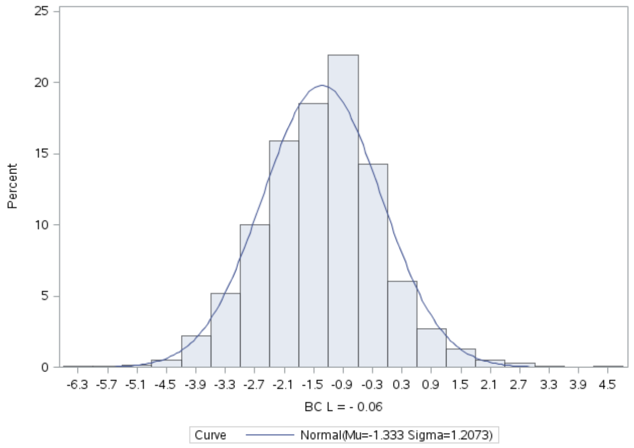


Figure 6.5: Proposed Box-Cox distribution



323. Western Power proposes to amend the access arrangement to specify the use of the Box-Cox transformation to determine the major event day threshold that applies to the calculation of SAIDI, SAIFI and call centre performance.

324. We have adjusted the historical data series to also apply the new definition of the major event day threshold to set the service standard benchmarks and targets for AA4.

6.6.2.3 Events considered in defining major event days

325. When calculating the major event day threshold, Western Power proposes to remove interruptions that are excluded for the purposes of measuring distribution reliability.

326. This relates to interruptions due to planned outages on the transmission network events, generation driven events, under frequency load shedding due to generation shortfalls and faults caused by customer equipment. This will ensure alignment between the events excluded in reporting on the SAIDI and SAIFI measures and the determination of the major event day threshold for SAIDI, SAIFI and call centre performance measures.

327. When benchmarking against historical performance or other distribution network service providers, it is common to remove all events that are outside of the network service provider's control. In its review of Distribution Reliability Measures, Final Report[77] the AEMC states:

> *[w]hen benchmarking the performance of distributors or applying an incentive scheme, it is common to remove events that are beyond the control of the distributor from the calculation of the reliability measures. Such events include:*
>
> *(1) lack of generation or a failure in the transmission network where the distributor can neither act to reduce the probability of such an event occurring nor manage the restoration of supply;*
>
> *(2) to comply with jurisdictional regulations; and*
>
> *(3) under direction from state or federal emergency services."*

77 Section 4, *Review of Distribution Reliability Measures, Final Report*, AEMC, 5 September 2014.

328. Making these exclusions from AA3 performance means the average number of major event days that occurred each year during the AA3 period reduces from 4.6 to 3.3 days.

329. For the purposes of setting the SSBs and SSTs for AA4, we propose to adjust historical data for the new definition of excluded events, including the new definition of the major event day threshold. This will mean that the change in definition will be financially neutral. We do not expect Western Power will receive financial rewards or penalties in relation to this methodological change.

330. This amendment will align Western Power's calculations with other Australian electricity transmission and distribution businesses.

6.6.3 Applying the distribution of best-fit to set SSBs

331. As in the AA3 period, Western Power has considered the distribution of best-fit to set the SSB for each measure.

332. For each combination of performance measure and statistical distribution, we have:

- fitted the chosen statistical distribution onto five years of rolling average data using maximum likelihood estimation
- performed a visual inspection of the raw data against the fitted distribution using quartile-quantile (**Q-Q**) and percentile-percentile (**P-P**) plots
- determined the theoretical distributions' goodness-of-fit using the Anderson-Darling test[78]
- discarded any distributions from further evaluation where the p-value from the Anderson-Darling test is below a threshold value of 0.05
- calculated the relative quality of the remaining statistical models via the Akaike Information Criterion (**AIC**) and ranking the distributions according to their AIC in descending order
- calculated the 1 per cent, 50 per cent and 99 per cent quantiles from the theoretical distribution with the lowest AIC value.

333. When determining the distribution of best fit, we found that a number of distributions were a close fit, but that the 99th percentile[79] of each varied significantly.

334. For example, Figure 6.6 shows the AIC and 99th percentile values for Rural Short SAIDI using Normal and Weibull distributions[80] since 2012. There are four transition points over the historic time period in which the lowest AIC could trigger selection of either the normal or the Weibull distributions. As a result, it could be concluded that over time the distribution of best fit will change over time.

335. At each of the transition points over the historical time period, the 'correct' 99th percentile varies by approximately 10 per cent.

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78 For discrete distributions, Pearson's Chi-Squared test was applied in place of the Anderson-Darling test.

79 For the majority of our reliability measures, the lower the value, the better the performance, however, for circuit availability and call centre, the higher the value, the better the performance. Throughout this document we refer to the 99th and 97.5th percentile as the point we have used for setting SSBs for simplicity, however, for circuit availability and call centre measures, where a lower value reflects poorer performance, we have used the 1st and 2.5th percentile.

80 Whichever line has the lowest value would be selected as the distribution of choice.

Figure 6.6: AIC calculated on a 5-year rolling basis for Rural Short SAIDI

336. This change in the distributions of best fit risks that a small change in the underlying data has a significant impact on the SSBs. In some cases, shifting from the best to the second best distribution of fit can result in a 10 to 20 per cent change in the proposed SSB.

337. To overcome the volatility introduced by small changes to the data Western Power proposes averaging all distributions considered to be a good fit[81]. In doing so we have:

- determined the statistical distribution of best fit
- discarded any distributions with an Anderson Darling p-value of less than 5 per cent
- sampled the distribution to obtain the 50th and 99th percentiles
- averaged the results for all distributions with an AIC within 1 per cent[82] of the distribution with the lowest AIC.

338. We consider the methodology for averaging distributions for AA4 will ensure more accurate estimation of the probability of these compliance measures being met, provide appropriate incentives for Western Power to maintain compliance under the service incentive framework, and ensure the setting of more consistent SSBs over time all else being equal.

81 Good fit is determined as having an AIC close to the lowest AIC.

82 A threshold that is too high would result in the all evaluated distributions being considered, departing from the principle that the SSB/SST should be based on the distribution of best fit. A threshold that is too low would result in only the single best distribution being considered, negating the rationale for averaging the 99th percentile values. The one per cent threshold provides a pragmatic trade-off between considering too many and too few candidate distributions.

6.6.4 Applying the 99th percentile of the fitted distribution to set our SSBs

339. Western Power proposes to use the 99th percentile[83] of the fitted distribution to set our SSBs for the AA4 period. This is higher than the 97.5th percentile used for the AA3 period.

6.6.4.1 It will allow compliance objectives to be met

340. Western Power has a strong culture of compliance and aims to meet all SSBs in each year. Setting the SSBs on the basis of the 99th percentile better aligns with this objective.

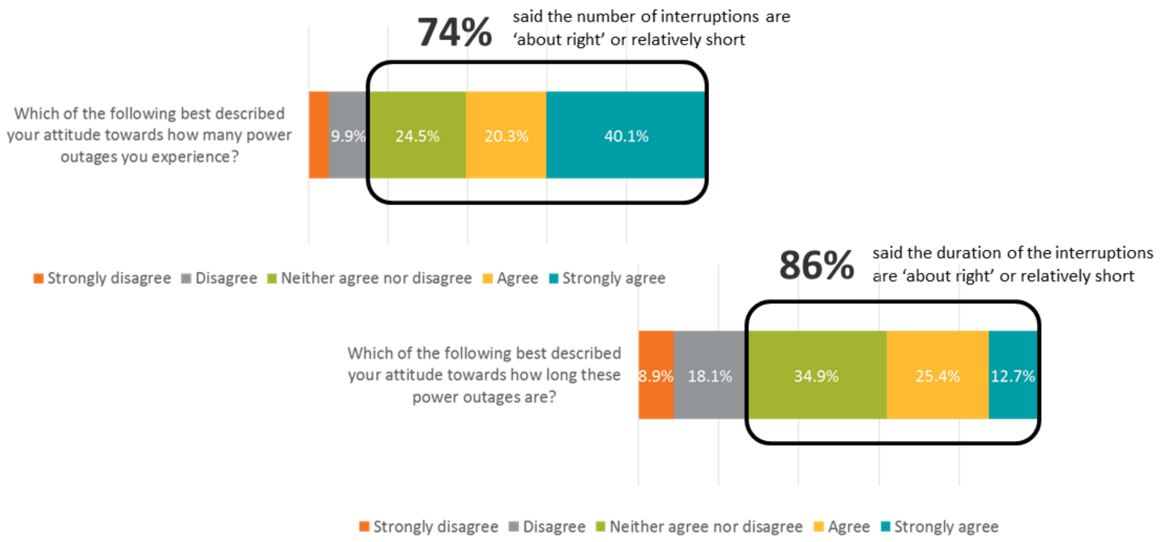
341. By design, setting the SSB from the 97.5th percentile should result in a 2.5 per cent likelihood of being non-compliant with each metric, assuming stable performance. Setting the SSBs at the 99th percentile will increase Western Power's overall likelihood of being compliant with the requirements under the Access Code and therefore our electricity distribution and transmission licences.

6.6.4.2 It will align with customer preferences to maintain service levels

342. Western Power proposes to maintain current service standards performance over the AA4 period, in line with customer expectations. If the SSBs continue to be set at the 97.5th percentile, Western Power has an incentive to improve reliability to ensure compliance, which is inconsistent with customer expectations.

343. As shown in Figure 6.7, through the customer engagement program, our customers indicated their general satisfaction with the current reliability performance of their electricity supply[84].

Figure 6.7: Customer insight #12 – Longer outages are more disruptive to customers than frequent (short) outages



344. On the basis that we will maintain the current level of performance on average, we consider it appropriate to choose a percentile value for the SSB that ensures that we are compliant. Choosing a lower threshold value would increase the risk that, in the absence of further investment (in alignment with customer

83 As previously noted, in this section we refer to the 99th and 97.5th percentile as the point we have used for setting SSBs for simplicity, however, for circuit availability and call centre measures, where a lower value reflects poorer performance, we have used the 1st and 2.5th percentile.

84 *Customer Insights Report*, Western Power, 2014.

feedback to maintain performance), service standards would not be met and Western Power would be financially penalised.

6.6.4.3 It will provide more stability for volatile measures

345. Where the performance of a measure is relatively consistent over time, the difference between the average of the 97.5th percentile of the distributions of best fit and the average of the 99th percentile is not material. This impact is more significant for volatile measures such as CBD SAIDI. Despite the change, SSBs will be the same or more stringent for all measures except for rural long SAIDI and SAIFI and average outage duration for AA4, compared to AA3.

6.6.5 Adjustment for the retirement of significant generation facilities in the network

346. We note that our historical transmission network performance is unlikely to be representative of performance over the AA4 period. As discussed in Chapter 8, we are currently considering the impact of the retirement of a number of generation facilities that are currently used for network reliability in constrained areas of the transmission network.

347. During the AA4 period we are expecting the retirement of the Muja AB, West Kalgoorlie and Mungara generators that are currently used for security of supply and network reliability. This will cause additional pressure on the network in all of our already constrained regional load areas:

- North Country
- East Country
- Eastern Goldfields
- Muja (which connects the South West).

348. We have not had time to fully consider the impact of these retirements in our investment plan. We are in the process of the annual update of our Network Development Plan, which will assess and document these impacts, however, we anticipate a significant impact on our transmission measures.

6.7 Service standard adjustment mechanism

349. Under section 6.30 of the Access Code, Western Power's access arrangement must contain a SSAM. Western Power's proposed SSAM provides financial rewards and penalties for service that is better or worse than the expected level of performance (which we expect to achieve 50 per cent of the time). The rewards/penalties are awarded in the following access arrangement period via a revenue building block adjustment.

350. The following sections discuss the parameters for the SSAM – the measures, service standard targets or SSTs, the incentive rates and the revenue at risk.

6.7.1 Measures

351. Western Power proposes that 13 of the 15 proposed AA4 SSBs, are used as SSTs to calculate the SSAM.

352. Aligned with our approach in AA3, street light measures are proposed be excluded from the SSAM in the AA4 period.

6.7.2 Service standard targets

353. Western Power proposes to set its SSTs that apply to the SSAM using a similar method as used for the AA3 period, in that the SSTs are set at the 50th percentile. As discussed in section 6.6.3, we propose to use the average of the 50th percentile of the distributions of best fit, consistent with the setting of the SSBs.

354. This method means the proposed SSTs for the AA4 period are the same or more stringent than during the AA3 period, except for rural long SAIDI and SAIFI, and average outage duration. This reflects the improvement in service performance (expect for rural long SAIDI and SAIFI, and average outage duration) over the AA3 period.

355. We have also proposed an adjustment to rural long SAIDI and SAIFI to account for the expected improvement in reliability performance associated with the Kalbarri microgrid project.

356. As discussed in section 6.6.1, we propose to continue to operate and invest in the business to meet the current suite of SSBs until the ERA makes a final decision on the amended access arrangement. We note that in the absence of any new agreed minimum standard, application of the AA3 SSBs as an interim measure is appropriate.

357. The design of the SSAM as an incentive regime, with its associated financial rewards and penalties should be the subject of well-measured and reasoned analysis. It should not be:

- a transitional measure, as would be the case with Western Power operating and investing in the network in line with our proposed AA4 SSAM and the associated SSTs
- retrospectively applied after the point that we would be able to affect the outcome, as would be the case with the back-dated application of the AA4 SSAM and the associated SSTs
- applied in a context different to the one in which it was intended, as would be the case with the continued use of the AA3 SSAM and the associated SSTs.

358. We therefore propose not to determine SSTs for the 2017/18 year. In practice, this will mean that we will not receive any SSAM rewards or pay any penalties for the first year of the AA4 period. We will continue to apply AA3 SSBs in 2017/18. This will ensure that the minimum standards are maintained, and our customers will not be worse-off.

359. The proposed SSTs are provided in Table 6.3.

Table 6.3: AA4 proposed service standard targets

Performance measure	Unit	AA3	2017/18	From 2018/19[85]
Distribution				
System average interruption duration index				
CBD	Minutes	20.3	-	17.8
Urban	Minutes	136.6	-	108.7
Rural short	Minutes	207.8	-	190.4

85 This assumes the revised access arrangement commences on or before 1 July 2018.

Performance measure	Unit	AA3	2017/18	From 2018/19[85]
Rural long	Minutes	582.2	-	675.6
System average interruption frequency index				
CBD	Number of events	0.14	-	0.14
Urban	Number of events	1.36	-	1.12
Rural short	Number of events	2.27	-	2.01
Rural long	Number of events	4.06	-	4.67
Calls responded to in 30 seconds	Per cent	87.6	-	92.2
Transmission				
Circuit availability	Per cent	98.1	-	98.5
Loss of supply event frequency				
>0.1 and ≤1 system minutes	Number of events	24	-	17
>1 system minutes	Number of events	2	-	1
Average outage duration	Minutes	698	-	871

360. The following sections detail each of the proposed changes to setting SSTs for the AA4 period. The complete methodology is provided in Attachment 6.2.

6.7.3 Adjustment for Kalbarri

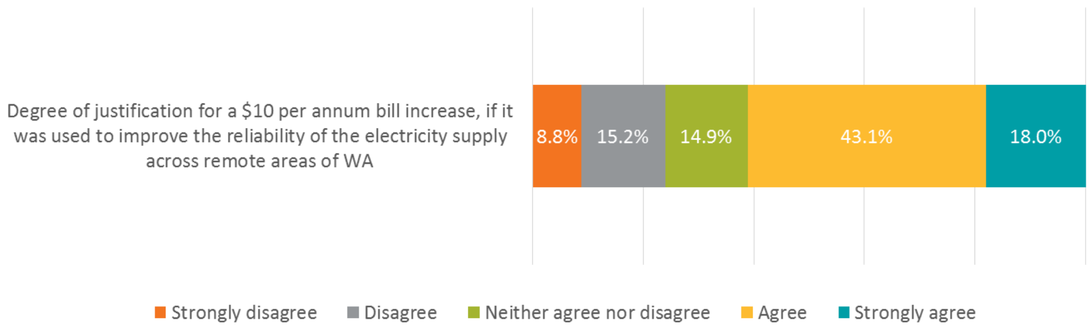
361. In AA4, Western Power proposes to spend $9.5 million to reduce the frequency and duration of outages in Kalbarri. The town of Kalbarri has been identified as a reliability hot spot. It is supplied solely through a 150 km, 33 kV feeder from Geraldton. In areas such as Kalbarri, generally located on the edges of the network, the cost per customer of improving performance of the network is prohibitive and challenging for it to be funded solely through the SSAM.

362. Through the customer engagement program, our customers said *a reliable source of electricity is essential for all customers and [they] are willing to spend money to ensure that all people on the network have a reliable source of electricity*.[86] The majority of our customers (61 per cent) told us that an increase in their annual bill of $10 was justified to improve the reliability of the electricity supply across remote areas of WA.[87]

86 Customer insight #13, *Western Power customer insights feedback report*, Deloitte, August 2016.

87 Customer insight #13, *Western Power customer insights feedback report*, Deloitte, August 2016.

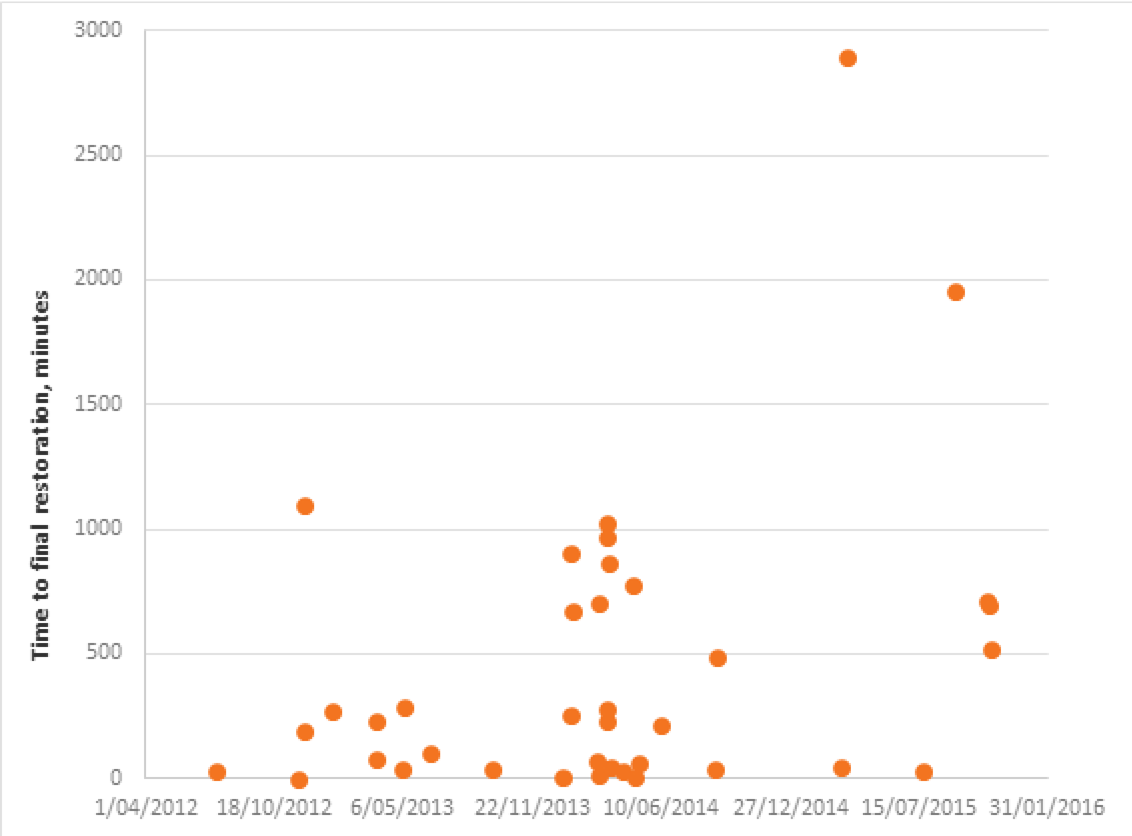
Figure 6.8: Customer insight #13 – a reliable source of electricity is essential for all customers and customers are willing to spend money to ensure that all people on the network have a reliable source of electricity



363. The radial nature of the Kalbarri feeder means supply to the township is inherently less secure than towns or regions with multiple sources of supply. Given the distances fault response staff often have to travel from Geraldton, therefore, outages in Kalbarri can last between five and eight hours.

364. As shown in Figure 6.9, between November 2014 and November 2015 Kalbarri residents experienced 19 significant power interruptions lasting between 30 minutes and, in the worst case, more than two days.

Figure 6.9: Outages impacting 500 or more customers in Kalbarri, time to final restoration, minutes



365. A range of potential solutions to the Kalbarri reliability problems have been considered and tested with the Kalbarri community. An October 2016 feasibility study recommended the development of a microgrid.

366. The proposed microgrid will have a utility-scale battery as the centrepiece. The battery will be charged by a combination of network, wind and solar and can support the needs of the community during an outage on the network between Geraldton and Kalbarri.

367. Acknowledging the project is expected to affect our overall rural network reliability when in operation, albeit a minor improvement, we have manually reduced our rural long SAIFI and SAIDI SSTs by 0.06 interruptions and 5.63 system minutes respectively.[88]

368. Further information on the Kalbarri microgrid project is provided in Chapter 8 and Attachment 6.3.

6.7.4 Valuing reliability for our customers

369. Western Power proposes to retain the AA3 methodology for setting the financial incentive rates for the SSAM, with updates to reflect a more contemporary estimate of the value to customers of a reliable supply of electricity, using:

- value of customer reliability estimates from the AEMO's 2014 study, adjusted to apply in WA, to set incentive rates for distribution measures
- revised weightings for the revenue at risk associated with each transmission measure as a result of the proposed exclusion of the system minutes interrupted measures from the SSAM
- the proposed AA4 revenue to determine transmission and call centre incentive rates.

370. This approach has resulted in lower financial incentive rates than those applied in AA3, with the exception of the loss of supply event frequency measures. This will result in lower rewards and penalties for the same change in performance relative to AA3.

6.7.4.1 Distribution network reliability and call centre incentive rates

371. Western Power proposes to use the value of customer reliability (**VCR**) estimates from the AEMO's 2014 VCR Final Report[89], adjusted to apply in WA, to set the financial incentive rates for our distribution reliability SSTs. These estimates provide an updated view from the AEMO 2012 approach[90], which was used by Western Power for AA3.

372. The VCR is used to represent, in dollar terms, our customers' willingness to pay for the reliable supply of electricity. We use the VCR to inform our investment decisions. The VCR acts as a proxy for the value customers place on an investment to improve reliability or maintain average reliability of service levels.

373. The VCR is applied under the SSAM to calculate the financial incentives that will apply to Western Power for each distribution reliability measure to ensure the framework drives economically efficient investment in the reliability of the network.

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88 These calculations are based on a 5 year simple average of expected performance impacts based on 2012/13 to 2016/17 historical performance. This is our current estimate. Our business case has not yet been finalised, and therefore this adjustment is subject to revision following the completion of our studies.

89 Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

90 The AEMO's 2012 approach determined VCRs based on findings by Oakley Greenwood (2011) and derived from Victorian surveys conducted in 2007.

374. We propose to use the VCR estimates in Table 6.4 to apply to our distribution reliability measures under the SSAM. These estimates are all significantly lower than those applied in AA3 and will therefore lead to lower rewards and penalties for the same change in performance relative to AA3.

Table 6.4: Value of customer reliability estimates, real $ at 30 June 2017, per kWh

	CBD	Urban	Rural short	Rural long
AA3 VCR estimates (escalated)	113.7	73.4	71.1	80.8
AA4 VCR estimates	51.0	43.2	41.9	43.1

375. In September 2014, the AEMO conducted a study to determine the VCR for each customer class for each jurisdiction in the National Electricity Market (**NEM**). As WA is not a participant jurisdiction in the NEM, there are no VCR estimates for WA included in the AEMO's study. Western Power has therefore developed its own VCR estimates. In doing so, we have engaged an independent economic consulting firm – Synergies Economic Consulting (Synergies) – to leverage the AEMO's study to the extent possible.

376. The AEMO's study calculated VCR values by jurisdiction for residential customers and NEM-wide VCR estimates for commercial and industrial customers.

377. Synergies' approach to determining probability-weighted VCR values for residential customers was to:

- choose a proxy NEM jurisdiction that it considers best reflects the drivers of value for WA energy customers
- apply the AEMO's VCR estimates for the proxy NEM jurisdiction by:
  - using Western Power's historical interruption data to calculate interruption probabilities for each customer class based on the time of day, weekday and season
  - multiplying the probability of each interruption by the corresponding VCR estimate.

378. Synergies considered South Australia was the most appropriate proxy jurisdiction for WA as the underlying drivers of the VCR estimate in South Australia are similar to WA.

379. Synergies' approach to determining the VCR estimates for commercial and industrial customers was to apply the AEMO's NEM-wide estimates by customer class. Further information on this process is provided in Attachment 6.4.

380. We have incorporated these updated VCR estimates into the SSAM on the basis of the AER's current, 2009 STPIS Guideline[91], consistent with the approach adopted for the AA3 period. The penalty and reward rates have been calculated using 12 months of consumption data to 30 June 2017.

381. The methodology for calculating the incentive rates for call centre response is consistent with the approach adopted for AA3 and consistent with the AER's 2009 STPIS Guideline[92]. They have been updated to reflect the forecast AA4 revenue and the current level of performance.

382. Table 6.5 shows the resultant SSAM incentive rates for the distribution measures.

91 *Electricity distribution network service providers: Service target performance incentive scheme*, AER, May 2009.

92 Page 16, *Electricity distribution network service providers: Service target performance incentive scheme*, AER, May 2009

Table 6.5: SSAM financial incentive rates for AA4 distribution measures, $ real at 30 June 2017

Performance measure	Unit	AA3		AA4 proposed	
		Reward	Penalty	Reward	Penalty
System average interruption duration index					
CBD	Minutes	$74,774	$74,774	$26,734	$26,734
Urban	Minutes	$584,170	$584,170	$366,800	$366,800
Rural short	Minutes	$246,398	$246,398	$114,374	$114,374
Rural long	Minutes	$71,910	$71,910	$41,958	$41,958
System average interruption frequency index					
CBD	Number of events	$96,015	$96,015	$30,114	$30,114
Urban	Number of events	$605,308	$605,308	$366,867	$366,867
Rural short	Number of events	$245,338	$245,338	$117,788	$117,788
Rural long	Number of events	$112,161	$112,161	$65,982	$65,982
Calls responded to in 30 seconds	Per cent	-$45,752	-$45,299	-$43,061	-$9,981

6.7.4.2 *Transmission network reliability values*

383. For the AA3 period, Western Power applied a percentage of its revenue at risk to each transmission measure. There were five transmission SSTs used in the SSAM calculation. For the AA4 period we propose to remove the system minutes interrupted measure as a SSB, and therefore also as an SST.

384. Western Power proposes to reallocate the revenue at risk previously allocated to the system minutes interrupted measure between the remaining four transmission measures as shown in Table 6.6.

Table 6.6: Transmission measure allocation of revenue at risk, per cent

Measure	AA3	AA4 proposed	Difference
System minutes interrupted	10.0	-	-10.0
Circuit availability	50.0	50.0	-
Loss of supply event frequency >0.1 and ≤1 system minutes	10.0	12.5	+2.5
Loss of supply event frequency >1	10.0	12.5	+2.5
Average outage duration	20.0	25.0	+5.0
Total	**100.0**	**100.0**	**-**

385. This reallocation maintains the allocation of the total transmission revenue at risk (one per cent of transmission revenue) to 50 per cent for security of supply measures (circuit availability) and 50 per cent for reliability of supply measures (loss of supply event frequency and average outage duration).

386. We have applied these weightings to the AA4 transmission revenue at risk.

387. Table 6.7 shows the resultant SSAM incentive rates for the transmission measures.

Table 6.7: SSAM financial incentive rates for AA4 distribution measures, $ real at 30 June 2017

Performance measure	Unit	AA3		AA4 proposed	
		Reward	Penalty	Reward	Penalty
Circuit availability	Per cent	-$901,021	-$450,510	-$421,856	-$187,492
Loss of supply event frequency					
>0.1 and ≤1 system minutes	Number of events	$40,045	$30,035	$42,186	$52,732
>1	Number of events	$180,204	$180,204	$140,619	$421,856
Average outage duration	Minutes	$3,834	$2,751	$1,826	$2,909

6.7.5 Capping rewards and penalties under the SSAM

388. Western Power proposes to retain the total caps on the revenue at risk under the SSAM at one per cent of transmission revenue and five per cent of distribution revenue.

389. When compared to AA3, the revenue requirement and therefore, revenue at risk, has increased for both transmission and distribution, as shown in Table 6.8. However, as this only caps the total amount Western Power can earn, its financial incentives are driven by the individual incentive rates applied to each measure. This will mean that it is unlikely Western Power will earn rewards anywhere near the level of the cap.

Table 6.8: AA3 and AA4 revenue at risk, $ real at 30 June 2017

	AA3	AA4 proposed	Change
Transmission	$3,180,400	$3,374,849	6%
Distribution	$41,381,000	$53,802,089	30%

390. We propose to retain the approach used in AA3 to fix the revenue at risk at the amount approved by the ERA in its final decision. This is different to our proposed pricing approach which will update the values on an annual basis (see Chapter 10). This will provide Western Power with certainty about our financial incentive rewards and penalties through the AA4 period. We do not expect this approach to result in windfall gains or losses as we don't expect our revenue to change materially in total over the period.

6.8 Investment adjustment mechanism

391. The investment adjustment mechanism (**IAM**) provides for an adjustment to target revenue for differences between actual and forecast capital expenditure in certain expenditure categories. The IAM exists to ensure

customers do not pay for forecasting errors in these nominated expenditure categories by providing a true-up for revenue in the next access arrangement period.

392. Western Power proposes to retain the methodology for calculating the IAM. However, we propose to change the categories of capex under the IAM for the AA4 period. In summary, we propose to:

- remove distribution wood pole management from the IAM
- remove the Rural Power Improvement Program (**RPIP**)[93] from the IAM
- include distribution metering in the IAM
- retain transmission and distribution growth capex in the IAM
- retain the SUPP in the IAM.

393. Section 6.15 of the Access Code requires Western Power to include an IAM in its access arrangement. It is to ensure Western Power and its customers remain economically neutral as a result of any differences between the forecast and actual capex for categories of expenditure that are largely variable and externally driven.

394. Each of our proposed amendments is discussed in the following sections.

6.8.1.1 Removal of distribution wood pole management

395. In its AA3 draft decision, the ERA decided[94] Western Power's wood pole management capex should be subject to the IAM to ensure it was appropriately incentivised (even if expenditure was above the AA3 allowance) to meet the Energy*Safety* Order 01-2009.[95] Western Power has now fulfilled its obligations under the Energy*Safety* Order and therefore proposes to remove its wood pole management capex from the IAM. This is consistent with the ERA's intention noted in its final decision:

> *The Authority's requirement to include wood pole replacement in the investment adjustment mechanism is a one-off and the Authority does not consider that wood pole asset replacement would be included in the investment adjustment mechanism past the third access arrangement period.*[96]

6.8.1.2 Removal of the RPIP

396. The RPIP was retained in the IAM for the AA3 period, however, no work in the RPIP has been undertaken since the AA2 period. No work under the RPIP is forecast for the AA4 period, therefore we propose to remove it from the IAM.

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93 The RPIP was a jointly funded Western Power and State Government initiative to upgrade the network to improve power reliability in 35 rural areas in the South-West and south coast regions of WA. The program commenced in 2004 and continued until 2010.

94 Page 136-137, *Draft Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 29 March 2012.

95 In September 2009, Western Power was issued with an Order by Energy*Safety* which required, among other things, that all unsupported rural poles which did not comply with required standards should be replaced or reinforced by 2015.

96 Page 210, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 5 September 2012.

6.8.1.3 *Inclusion of distribution metering*

397. Western Power proposes the distribution metering regulatory category of capex be included in the IAM to ensure that the deployment of advanced meters is not unduly constrained by the capex forecast. Investment in distribution metering is forecast to be $166 million. This includes a total of $43 million of incremental expenditure over three years to move from the current basic meter standard to the advanced meter standard.

398. During our customer engagement program, we found that customers who have been educated about electricity tariffs are more likely to support a time of use tariff[97], and customers who support a time of use tariff are willing to pay for technology that allows them to monitor their usage.[98] It is clear there is some appetite among customers for advanced meters, therefore we are proposing a prudent implementation of advanced meters, installing advanced meters as the standard default meter for new meters and as old meters are scheduled for replacement.

399. However, should Synergy (or other retailers in the advent of full retail contestability in WA) decide to promote the benefits of advanced metering to support its retail product offerings, it is likely that demand for advanced meters will increase significantly. If demand for advanced meters increases above historical volumes, Western Power may need to replace up to a further 896,000 meters with smart meters, at an additional cost of $454 million. Therefore, we propose to make distribution metering subject to the IAM to accommodate for any large scale additional uptake of advanced metering.

400. Conversely, should Western Power be unable to implement advanced metering as proposed, for example if competing requirements mean metering replacement is deferred (as was the case during AA3 with the Energy*Safety* Order), the IAM would mean customers would be compensated in AA5 for the portion of the program not delivered.

6.9 Gain sharing mechanism

401. The GSM provides a financial incentive to reduce non-capital costs or improve productivity over the access arrangement period. GSM adjustments are only applied if all SSBs are achieved, and is designed to ensure Western Power only receives a reward where cost savings or productivity improvements do not come at the expense of lower service to customers.

402. Western Power proposes to retain the existing GSM in the AA4 period, with two minor amendments. We propose to calculate the GSM adjustments relating to transmission and distribution service standard performance separately. We have also updated the inputs used to determine the network growth factors and efficiency and innovation benchmarks, which are used to calculate the GSM reward. The proposed calculations are provided in Chapter 10.

6.9.1 Separation of the calculation of transmission and distribution GSM rewards

403. We propose to split the GSM into two separate mechanisms for the AA4 period – one mechanism for transmission and one mechanism for distribution.

404. Under sections 6.26 and 11.1 of the Access Code, the GSM must be linked to SSB performance. In the AA3 period, a single GSM applied across both the transmission and distribution networks. This means Western

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97 Customer insight #6, *Western Power customer insights feedback report*, Deloitte, August 2016.

98 Customer insight #9, *Western Power customer insights feedback report*, Deloitte, August 2016.

Power foregoes any reward for efficiency improvements if customers do not receive the minimum level of service for each of the SSBs in each year of the access arrangement period.

405. Our proposed approach will be consistent with the operational structure of Western Power's business. Western Power operates and maintains its transmission network separately from its distribution network. It has distinct works programs, design and operational workforces.

406. Separating the GSM into transmission and distribution will ensure:

- each workforce is held accountable for its own performance
- Western Power is provided with an equal incentive to achieve efficiencies in both the distribution and transmission networks
- the incentive to achieve efficiencies in one network is not weakened by poor service performance in the other network
- the current ambiguity regarding the appropriate allocation of GSM rewards between distribution and transmission target revenue requirements is removed.

407. During the AA3 review process, Western Power proposed to similarly de-couple the performance of each network under the SSAM. This approach was supported by the ERA, which accepted in its draft decision that the approach provided a means to remove the 'discontinuity' in the SSAM[99], and by WACOSS, which stated:

> *... Western Power's proposal to move to a combination of minimum standards and performance targets to enable it to earn rewards on a target-by-target basis. It is reasonable for Western Power to earn some part of the service standard bonus where it meets some, but not all of the performance targets.*[100]

6.9.2 Updated GSM input values

408. Western Power proposes to retain its methodology for calculating rewards under the GSM, with updates as follows:

- We propose to calculate the efficiency and innovation benchmarks separately for transmission and distribution opex categories. This aligns with our proposed GSM calculation methodology (see section 6.9.1).
- We propose to calculate and apply the network growth factors separately for transmission, distribution, corporate and indirect costs and align the adjustment of the efficiency and innovation benchmarks with our proposed application of network growth. This is consistent with our proposed opex forecasting methodology (see Chapter 7).
- We propose to update our uncontrollable opex costs to reflect those forecast for the AA4 period. This will ensure that Western Power is not unintentionally penalised or rewarded for forecasting errors associated with the cost of activities that it cannot influence.

409. These changes are discussed in the following sections.

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99 Page 434, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 5 September 2012.

100 Page 18, *WACOSS Submission on the ERA's Draft Decision,* WACOSS, 2012.

6.9.2.1 Application of network growth factors

410. Consistent with the approach adopted for the AA3 period, we propose to retain the requirement to adjust the efficiency and innovation benchmarks to account for actual, independently audited growth of the network, rather than the forecast.

411. We have updated the efficiency and innovation benchmarks adjustments to apply separate transmission and distribution network growth factors. This is consistent with how we propose to apply the network growth factors to the transmission and distribution forecasts for the AA4 period.

412. Table 6.9 shows the transmission and distribution network growth factors that we have used to escalate the AA4 opex forecasts.

Table 6.9: Network growth factors, per cent

	2017/18	2018/19	2019/20	2020/21	2021/22
Transmission					
Circuit length	0.32	0.33	0.22	0.33	0.32
Ratcheted max. demand	0.00	0.00	0.00	0.00	0.00
Energy delivered	0.30	0.00	2.89	2.50	0.00
Weighted entry and exit connection point	-0.24	-0.73	-0.25	-0.98	0.00
Transmission weighted average	**0.09**	**-0.11**	**0.62**	**0.35**	**0.09**
Distribution					
Customers	1.65	1.73	1.69	1.66	1.63
Circuit length	0.91	0.91	0.91	0.91	0.91
Ratcheted max. demand	0.00	0.00	0.00	0.00	0.00
Distribution weighted average	**1.21**	**1.26**	**1.24**	**1.22**	**1.20**

413. To adjust the efficiency and innovation benchmarks for actual, independently audited growth of the network, rather than the forecast, we propose to:

- calculate the network growth factors for transmission and distribution, and apply those directly
- calculate the weighted average of the transmission and distribution network growth factors that apply to:
  - corporate opex using the proportion of corporate opex allocated to each, in accordance with the Cost and Revenue Allocation Methodology and as reflected in the Regulatory Financial Statements for the relevant financial year
  - indirect costs as the proportion of transmission and distribution total expenditure that attracts indirect costs, in accordance with the Cost and Revenue Allocation Methodology and as reflected in the Regulatory Financial Statements for the relevant financial year.

414. Table 6.10 shows the weighted average growth factor that we have used to escalate the AA4 corporate and indirect cost forecasts.

Table 6.10: Weighted average network growth factors for corporate and indirect costs, per cent

	2017/18	2018/19	2019/20	2020/21	2021/22
Corporate	0.91	0.90	1.08	0.99	0.91
Indirect costs	0.93	0.92	1.09	1.01	0.92

6.9.2.2 Adjustments to the efficiency and innovation benchmarks

415. Consistent with the approach in AA3, we propose to adjust the efficiency and innovation benchmarks for uncontrollable costs incurred over the AA4 period. This will ensure that Western Power is not unintentionally penalised or rewarded for forecasting errors associated with the cost of activities that it cannot influence.

416. We have updated the efficiency and innovation benchmarks adjustments to reflect the AA4 forecasts for our uncontrollable opex.

417. Table 6.11 and Table 6.12 show the efficiency and innovation benchmarks for transmission and distribution for the AA4 period, based on the forecast opex, adjusted for uncontrollable costs.

Table 6.11: Transmission efficiency and innovation benchmark, $ million real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22
Total forecast transmission revenue cap opex	**93.8**	**84.2**	**83.2**	**84.6**	**84.6**
Adjustments:					
Superannuation costs for defined benefits schemes	-0.05	-0.05	-0.05	-0.05	-0.05
Energy*Safety* levy	-1.19	-1.19	-1.20	-1.20	-1.21
ERA costs (incl. licence fees and charges, standing charges, audits and specific costs)	-0.44	-0.30	-0.30	-0.30	-0.44
D-factor project costs	-	-	-	-	-
Unforeseen events	-	-	-	-	-
Technical Rules changes	-	-	-	-	-
Transmission efficiency and innovation benchmark	**92.2**	**82.6**	**81.6**	**83.0**	**82.8**

Table 6.12: Distribution efficiency and innovation benchmark, $ million real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22
Total forecast distribution revenue cap opex	**292.5**	**268.3**	**266.5**	**272.6**	**274.8**
Adjustments:					
Superannuation costs for defined benefits schemes	-0.15	-0.15	-0.15	-0.15	-0.15
Energy*Safety* levy	-3.26	-3.26	-3.28	-3.29	-3.30
ERA costs (incl. licence fees and charges, standing charges, audits and specific costs)	-1.19	-0.83	-0.83	-0.83	-1.21
D-factor project costs	-	-	-	-	-
Unforeseen events	-	-	-	-	-
Technical Rules changes	-	-	-	-	-
Distribution efficiency and innovation benchmark	**287.9**	**264.1**	**262.3**	**268.4**	**270.1**

6.10 D-factor scheme

418. Western Power proposes to retain the D-factor scheme during the AA4 period with minor administrative amendments to increase the timeliness of the process, and to provide certainty to Western Power on the outcomes of the ERA's assessment of D-factor projects.

419. The D-factor allows Western Power to recover an amount through target revenue in the next access arrangement period in respect of any additional:

- opex incurred as a result of deferring a capex project during the next access arrangement period
- opex incurred in the next access arrangement period in relation to demand management initiatives or network control services, where that opex meets the requirements of section 6.40 and 6.41 of the Access Code.

420. In its AA3 final decision, the ERA decided to exclude Western Power's forecast network control service costs from its AA3 opex allowance and instead require these costs to be recovered under the D-factor.[101] During the AA3 period, Western Power incurred costs associated with two network control services contracts.

421. There is currently some ambiguity about the drafting of the D-factor scheme provisions in the access arrangement. To address these ambiguities, Western Power proposes to clarify that it is able to seek ERA

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101 Page 91, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network,* ERA, 5 September 2012.

approval of D-factor costs outside of an access arrangement review process (i.e. during the access arrangement period). Further, within 25 business days[102] of the receipt of a submission, we propose to require the ERA to make a decision on whether the costs of that D-factor project meet the requirements of sections 6.40 and 6.41 of the Access Code, and therefore these costs can be added to the target revenue in the next access arrangement period.

422. The benefits of this change are:

- Western Power can invest in non-network solutions with greater confidence that the revenue can be recovered, which in turn increases the power of the D-factor incentive. As a result, customers are likely to benefit from innovation and demand management activities, which can be used to mitigate the need for costly capital investment. This is particularly important for non-network solutions and demand management solutions that are recurring through the access arrangement period.
- The D-factor is designed to offset the bias towards capex projects that the IAM provides. That is, if the D-factor did not exist, or did not provide an effective incentive, Western Power would be incentivised to spend capex (to be adjusted in the following access arrangement period) rather than opex. This is because, without the D-factor, the cost of a non-network solution over and above the approved opex forecast could not be recovered from customers, and would also reduce any potential rewards under the GSM. This would incentivise Western Power to invest capex on major augmentations to avoid the risk of being penalised for higher than forecast opex
- Due to the innovative nature of new non-network and demand management solutions, there is a greater risk around the likelihood of success. Therefore, in the absence of an effective incentive scheme, network service providers may have a bias towards investment in traditional network solutions. That is, there will be no incentive to develop capacity in non-network and demand management solutions.

6.11 Unforeseen and trigger events

423. Western Power proposes three changes to unforeseen and trigger events for the AA4 period:

- include a new unforeseen and trigger event relating to ‘Government-led reforms’
- remove the mandated roll out of advanced interval meters as a trigger event
- remove the redundant reference to the carbon pricing mechanism announced in 2011.

424. All other unforeseen events and trigger events will be retained as per the AA3 period.

425. Section 6.6 of the Access Code allows Western Power to recover prudent and efficient capex and opex incurred during a previous access arrangement period as a result of a force majeure event[103] that are unable to be recovered under Western Power’s insurance policies[104].

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102 This timeframe has been proposed as it aligns with the timeframes for the ERA to determine whether a major augmentation proposal meets the regulatory test requirements under subchapter 9.2 of the Access Code.

103 Under the Access Code ‘force majeure’ is defined as: *a fact or circumstance beyond the person’s control and which a reasonable and prudent person would not be able to prevent or overcome*.

104 Insurances must reflect the type and level of cover held by a reasonable and prudent person. Further information on Western Power’s proposed expenditure related to insurances is provided in Chapter 7.

426. Sections 5.34 and 5.35 of the Access Code allow Western Power or the ERA to specify one or more events in the access arrangement, after which have occurred, require Western Power to submit proposed revisions to its access arrangement.

427. Any Government-led reform, such as those proposed under the EMR some of which have recently been reaffirmed by the Minister for Energy[105], could have a significant impact on Western Power's expenditure. As these would be mandated and largely outside of Western Power's control, we should be provided with the opportunity to recover these costs either:

- in-period using the trigger event provision to re-open the access arrangement
- in the following access arrangement period using the unforeseen event provision.

428. As it is proposed that advanced meters be subject to the IAM, we consider there is no need to retain a mandated roll out of advanced meters as an example of a trigger event. Nevertheless, this removal would not prevent us from using these mechanisms if there was any significant unforeseen costs as the result of a Government-led reform.

429. We have removed the redundant reference to the carbon pricing mechanism that was introduced in 2011, but retained the broader reference to the introduction of any scheme or mechanism with respect, directly or indirectly, to emissions of greenhouse gases.

430. We note that the provision of specific events in the access arrangement are examples only, and do not limit the application of these clauses.

6.12 Technical Rules changes

431. Western Power is proposing to retain the existing Technical Rules changes provisions for the AA4 period with a minor adjustment to clarify that Western Power will only report on changes where the costs are material.

432. Sections 6.9 to 6.12 of the Access Code provide a mechanism to adjust Western Power's AA5 target revenue for any differences in actual capex or opex as against the AA4 forecast expenditure required to meet its Technical Rules obligations arising from amendments during the AA4 period.

433. Western Power proposes to amend the access arrangement to clarify that it will report on each change to the Technical Rules that result in **material** changes to the costs incurred or savings achieved in AA4. This is because we consider that the cost of completing a full cost-benefit assessment of each non-material change to the Technical Rules as part of an access arrangement revision submission will outweigh the benefits. As part of any proposed Technical Rules amendments, we will assess and provide to the ERA the expected costs and benefits.

6.13 Actual performance and proposed service standards

434. Figure 6.10 to Figure 6.24 show the service standard benchmarks and targets proposed for the AA4 period in the context of historical benchmarks, targets and actual performance.

105 This includes the Minister for Energy's re-affirmation to extend retail choice and move from an unconstrained to a constrained access regime by 2020.

435. The actual data is presented on the basis of the changes proposed for the AA4 period unless otherwise stated.

6.13.1 Distribution measures

Figure 6.10: CBD SAIDI

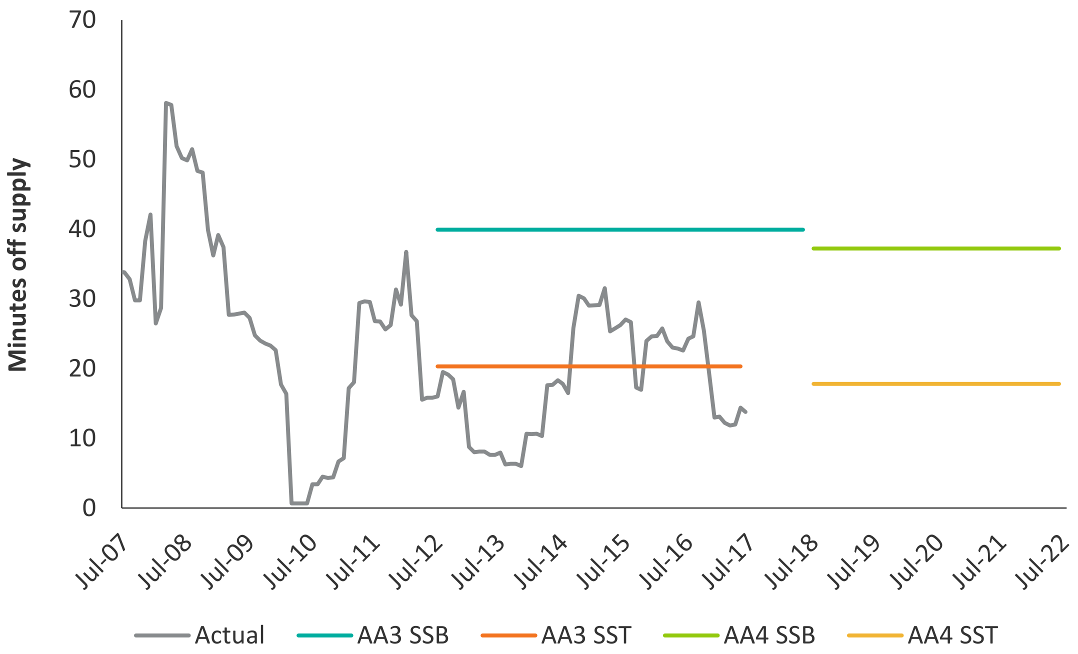


Figure 6.11: Urban SAIDI

Figure 6.12: Rural short SAIDI

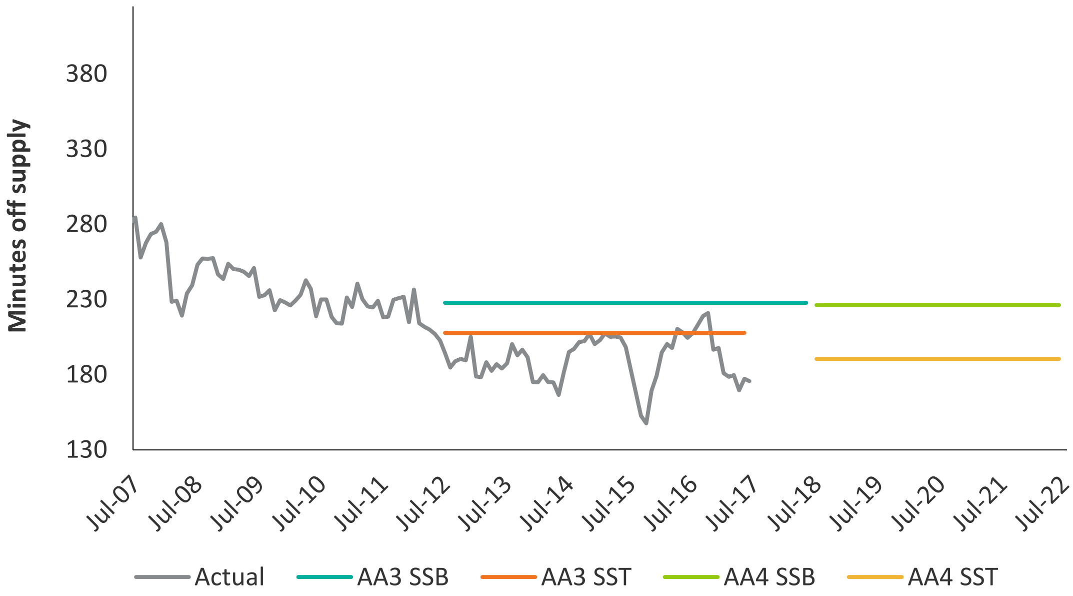


Figure 6.13: Rural long SAIDI

Figure 6.14: CBD SAIFI

Figure 6.15: Urban SAIFI

Figure 6.16: Rural short SAIFI

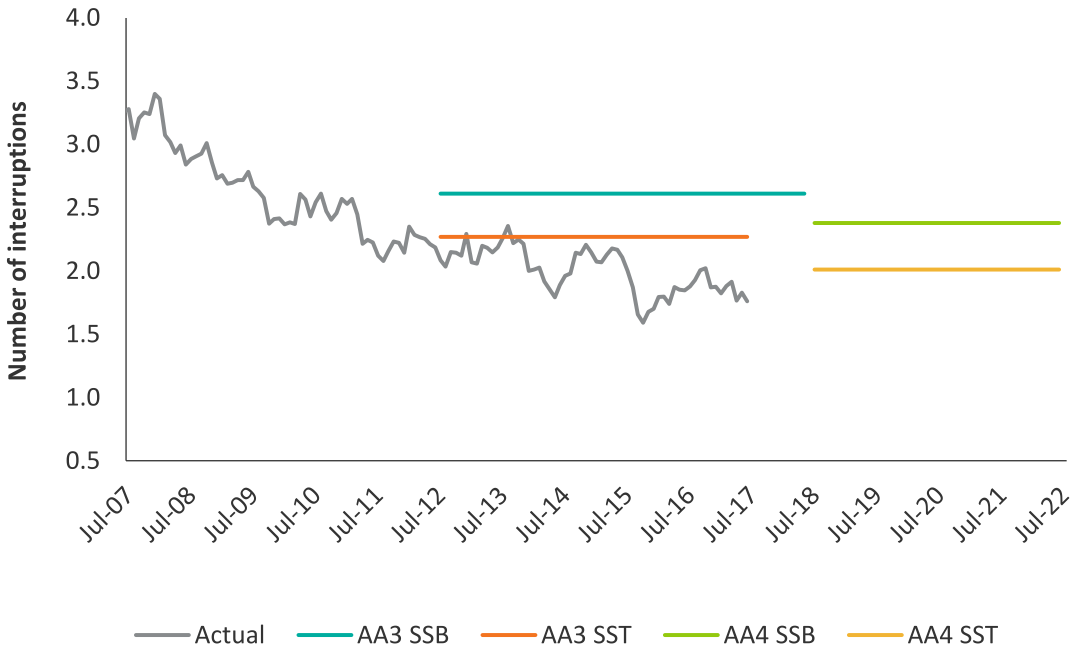


Figure 6.17: Rural long SAIFI

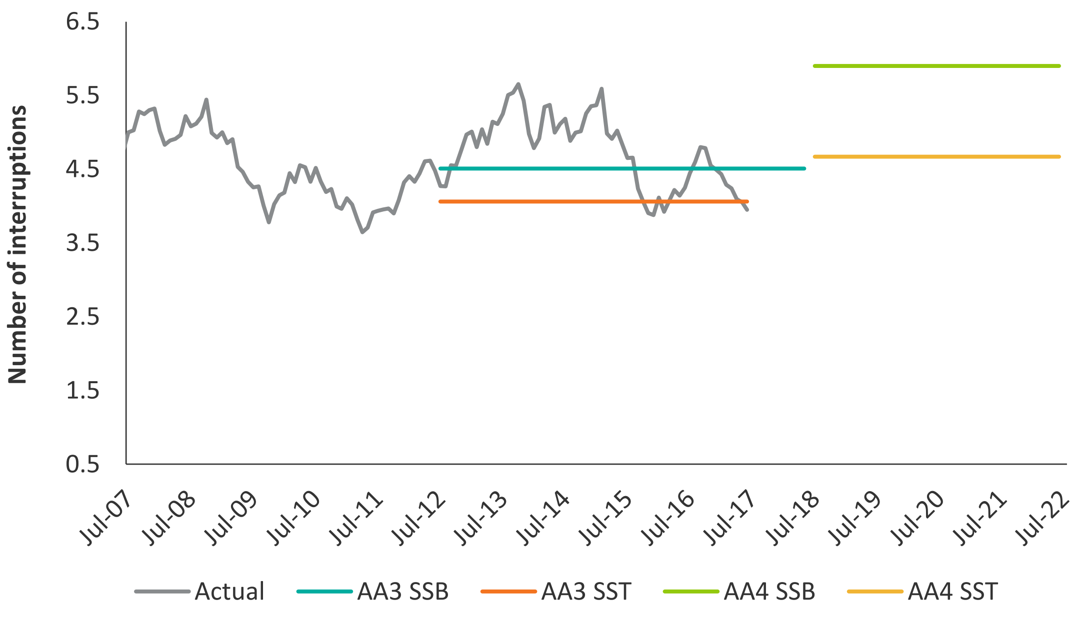
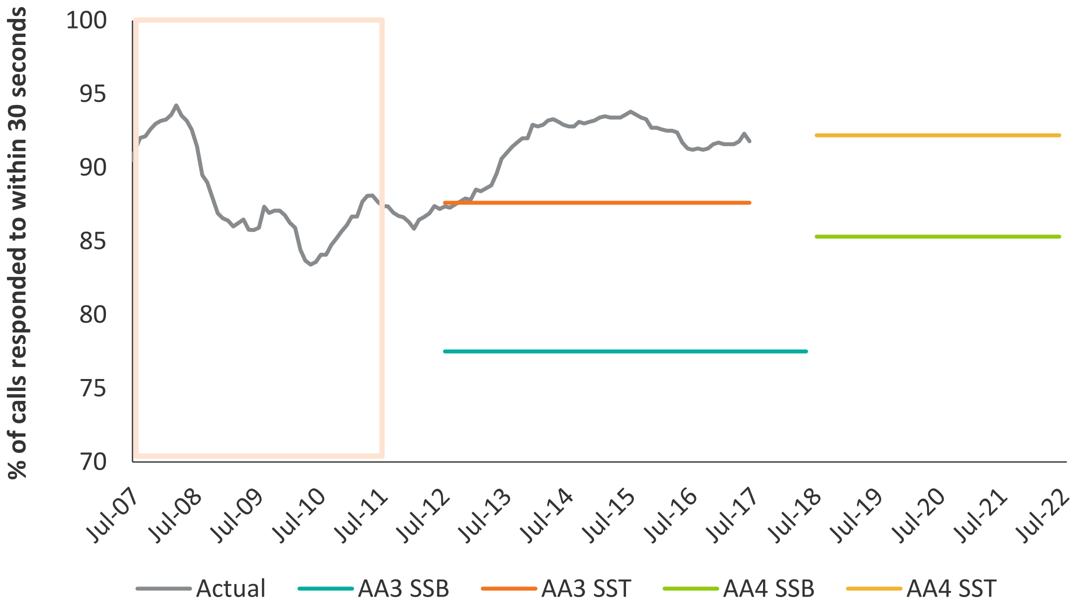
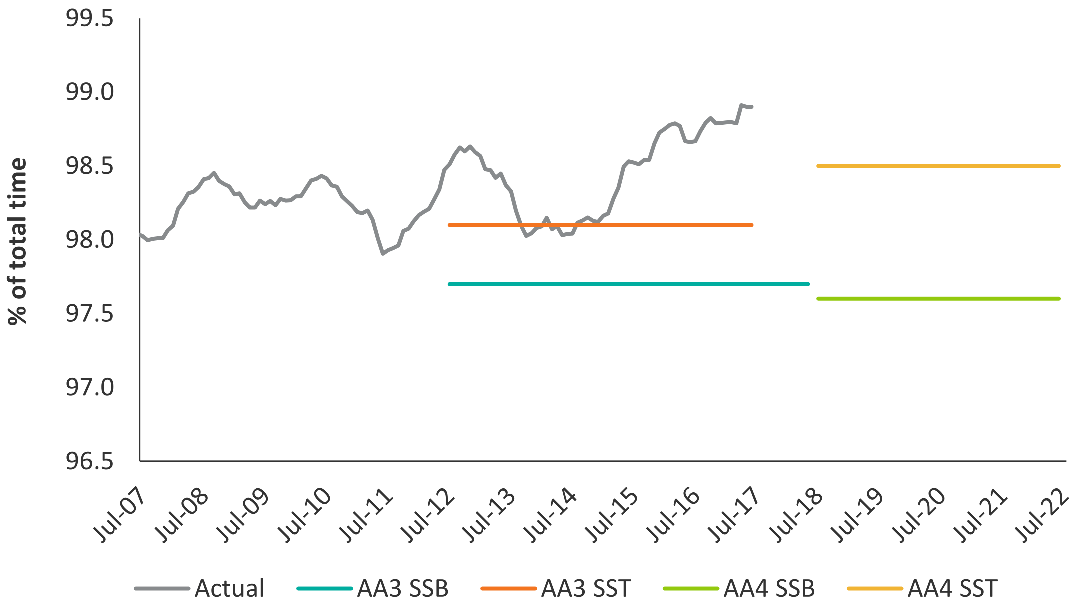


Figure 6.18: Call centre[106]



6.13.2 Transmission measures

Figure 6.19: Circuit availability



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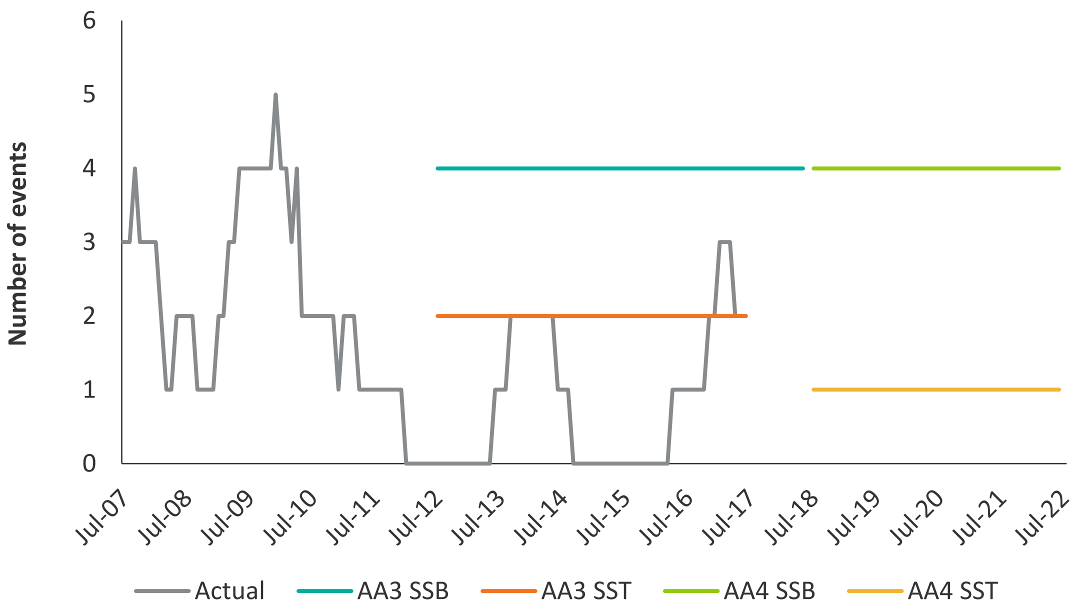
106 Prior to 2011, the actual performance for call centre has not been adjusted to reflect the proposed change to major event days, as only the reported data was able to be accessed at the time of developing this submission. However, as the AA4 SSBs and SSTs are calculated on the basis of the previous five years, this has not affected the proposed benchmarks and targets and is only provided for illustrative purposes.

Figure 6.20: Average outage duration

Figure 6.21: Loss of supply event frequency >0.1 and ≤ 1

Figure 6.22: Loss of supply event frequency >1



6.13.3 Street light network measures

Figure 6.23: Street lights metropolitan area repair time

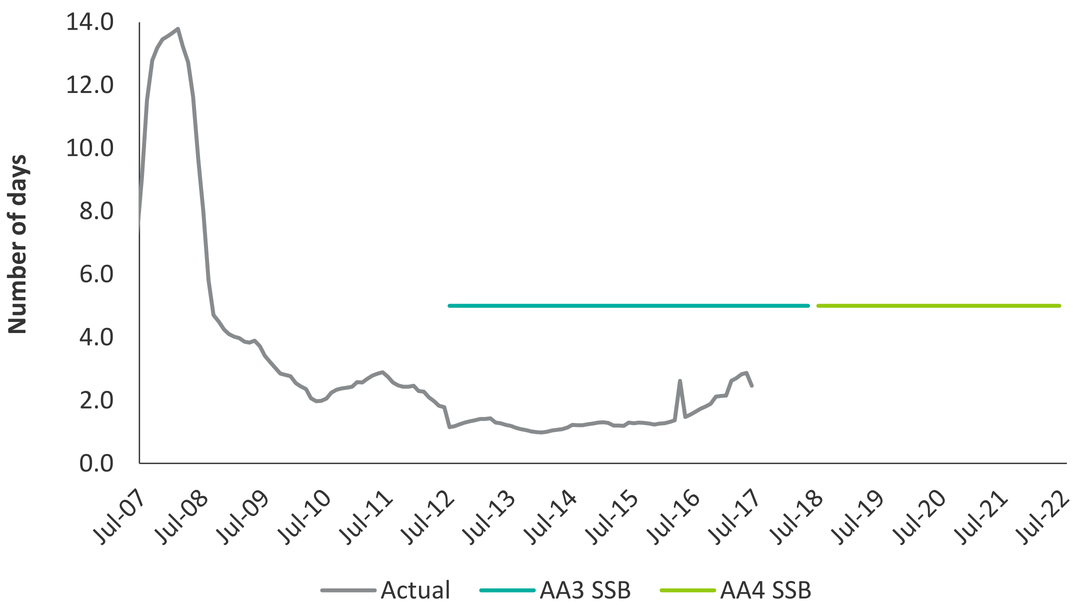
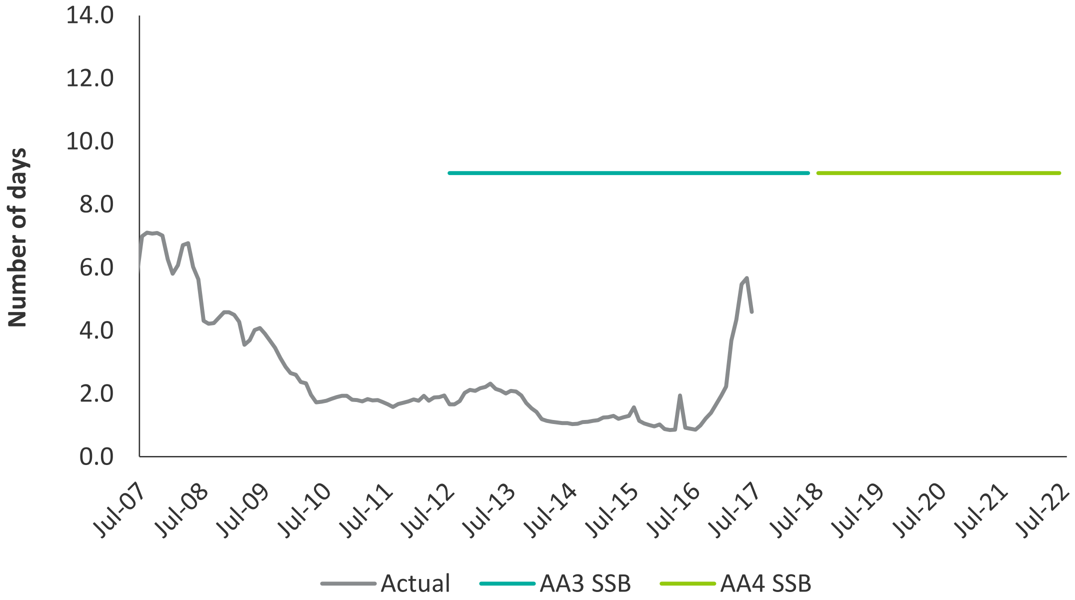


Figure 6.24: Street lights regional area repair time



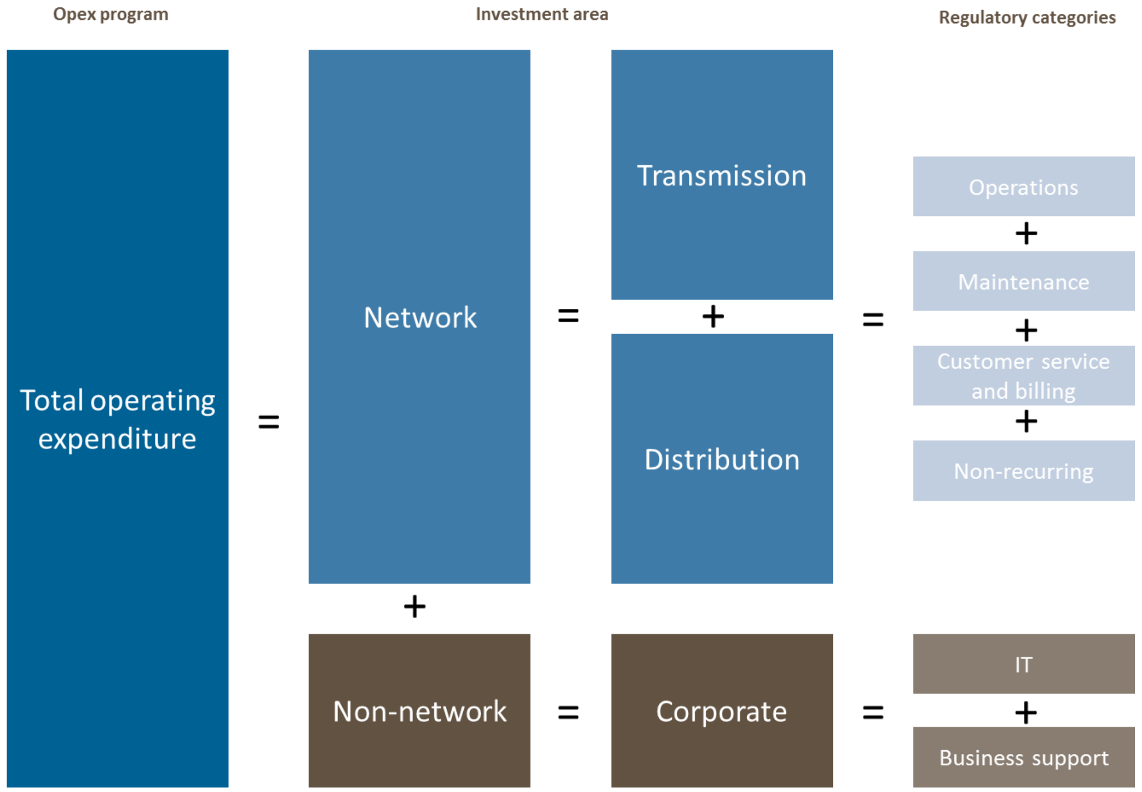
7. Operating expenditure

436. This chapter provides the methodology used to determine the forecast operating expenditure required by Western Power over the AA4 period. It also provides an overview of the opex forecasts, including the rationale for any changes from the AA3 period.

437. The opex forecast over the AA4 period is consistent with section 6.40 of the Access Code in that it contains only non-capital costs that would be incurred by a service provider efficiently minimising costs.

438. Western Power's opex is split into the categories shown in Figure 7.1.

Figure 7.1: Regulatory operating expenditure categories



439. We have used the 'base-step-trend' method to forecast recurrent opex. The base-step-trend method is widely used and accepted by regulators to determine the efficient level of opex for network businesses. In summary, the method takes the most recent efficient year of opex and adjusts the level of expenditure for:

- any expenditure not reflective of the recurrent cost **base**
- categories of opex impacted by discrete **step** changes
- changes in output and cost input **trends** over the period.

440. Over the AA4 period, we will incur additional opex in relation to providing non-revenue cap services. However, as these services are undertaken in response to customer requests, and paid for directly by the customer served, they **do not** form part of the AA4 period revenue requirement and **have not** been discussed in this chapter. The costs and revenue associated with non-revenue cap services are allocated in accordance with the Cost and Revenue Allocation Methodology (see Attachment 7.1).

7.1 Regulatory framework

441. Western Power's opex forecast is required to meet the Access Code objective, which is:

> *to promote the economically efficient investment in; and 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.*

442. Section 6.40 of the Access Code requires Western Power's opex forecasts to include only those non-capital costs which would be incurred by a service provider efficiently minimising costs.

443. Sections 6.41 and 6.42 of the Access Code provide for Western Power to recover opex where it is incurred as an alternative to providing covered (regulated) services through investing in a major augmentation of the network:

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.

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.

444. Western Power submits that the AA4 opex forecast, as determined by the base-step-trend method, reflects the expenditure that would be incurred by a network service provider efficiently minimising costs.

7.2 Overview of the operating expenditure proposal

445. Western Power forecasts it will incur $1,805 million[107] in opex to operate and maintain its transmission and distribution networks during the AA4 period. This will be recovered via the AA4 period revenue requirement, comprising:

- $310 million of opex on the transmission network
- $1,044 million of opex on the distribution network
- $451 million of corporate opex to support the provision of network services.[108]

446. This opex program will enable Western Power to continue to provide the safe, reliable and efficient electricity supply that our customers have told us they value. As described in Chapter 4, insights from our customer engagement program suggest that *while customer are sensitive to price increases*[109], they also consider *a reliable source of electricity is essential for all customers, and customers are willing to spend money to ensure all people on the network receive this*.[110]

447. With this in mind, we have balanced our opex proposal to ensure it provides sufficient revenue to cover the costs of maintaining a safe and reliable network, while efficiently minimising expenditure so that the flow-through impact on customers' electricity prices is low. Using the base-step-trend approach, we have based our opex forecasts on the efficient costs incurred during 2016/17. This means the forecast recurrent operating costs for the AA4 period incorporate the efficiencies achieved by Western Power's Business Transformation Program over the past two years.

448. Over the AA3 period Western Power made significant efficiency improvements in its Business Transformation Program, which sought to challenge and reduce costs to a more efficient and long-term sustainable level. Through a combination of asset management practice improvements, changes to the organisation's operating model, and external expenditure review, we have already realised $330 million in recurring cost savings by the end of the AA3 period.[111] Figure 7.2 shows how historical opex has reduced over the AA3 period and how it compares to forecast opex.

449. Note that Figure 7.2 and Table 7.1 include real cost escalation and indirect costs. Unless otherwise stated, all other expenditure numbers in this chapter **do not include real cost escalation and indirect costs**.

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107 Including real cost escalation and expensed indirect costs.

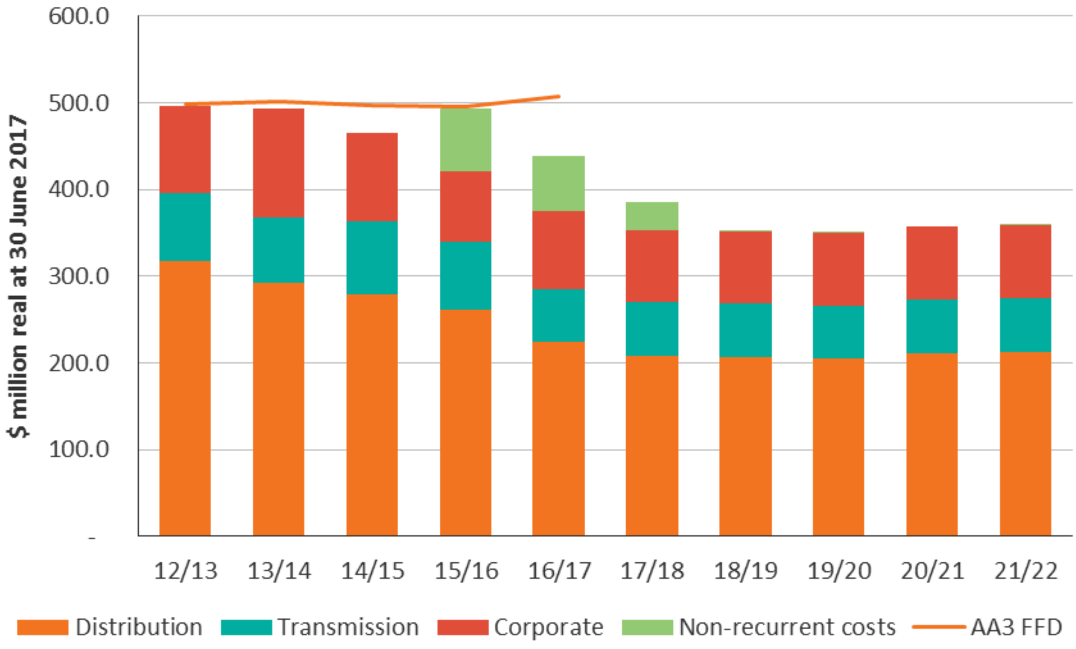
108 Including insurance costs, rates and taxes, regulatory levies and fees, as well as business support services divisional costs.

109 Insight # 1 from Western Power's customer engagement program.

110 Insight # 13 from Western Power's customer engagement program.

111 This includes $207 million of capex, $51 million of opex and $43 million of indirect cost efficiencies.

Figure 7.2: AA3 historical and AA4 forecast opex including indirect costs and escalations, $ million real at 30 June 2017



450. Western Power's 2016/17 efficient base year level of opex is $318 million.[112] This is 28 per cent lower than the $444 million 2016/17 recurrent opex forecast that was approved by the ERA in its AA3 further final decision. This reduction is primarily the result of Western Power's Business Transformation Program.

451. The benefits of Western Power's lower operating costs are now being passed through to customers through a lower 'base year' level of opex, which is used to forecast opex over the AA4 period. Further information on the Business Transformation Program is provided in Chapters 3 and 5, and in the sections below.

452. The strides Western Power has taken in reducing its operating costs means using 2016/17 as the base year sets an efficient and sustainable platform for ongoing opex during the AA4 period. Table 7.1 summarises the total AA4 opex forecast, **including real cost escalation and indirect costs,** split between opex required to operate and maintain the transmission and distribution networks, and corporate support opex.

Table 7.1: AA4 forecast opex summary including indirect costs and escalations, $ million real at 30June 2017

Expenditure category	17/18	18/19	19/20	20/21	21/22	AA4
Distribution	208.0	206.7	205.4	211.3	212.9	**1,044.3**
Transmission	63.0	61.7	60.8	62.2	61.9	**309.6**
Corporate	115.4	84.1	83.5	83.7	84.5	**451.2**
Total opex	**386.4**	**352.5**	**349.7**	**357.2**	**359.3**	**1,805.1**

112 Recurrent opex only. Non-recurrent costs are not included in the efficient base year.

453. Actual recurrent opex during the final year of the AA3 period (2016/17) was $375 million[113], which is:

- $122 million or 25 per cent lower than actual opex in the first year of the period (2012/13)
- $133 million or 26 per cent lower than the 2016/17 forecasts approved by the ERA in its AA3 further final decision.

454. The $318 million efficient base year is determined by excluding approximately $64 million of costs associated with activities that we do not expect to be incurred during the AA4 period. The efficient base year opex comprises:

- $182 million of recurring opex on the distribution network
- $53 million of recurring opex on the transmission network
- $83 million of recurring corporate opex.

455. We have applied network growth escalation to scale this opex forecast over time in line with the growth in the size of the network and customer base. We have also applied labour cost escalation of between 0.8 and 1.2 per cent per annum to the opex forecast.

456. We have made a one per cent per annum productivity adjustment to our opex forecasts. In accordance with the base-step-trend methodology, we have accounted for the expected improvements in productivity. The forecast productivity gains are passed through to our customers as savings and reflect our commitment to efficiently manage the business over the AA4 period.

457. In addition to the base year recurrent costs, we have identified a number of discrete activities that will require opex over the AA4 period. This includes:

- $28.3 million associated with the completion of the Business Transformation Program which is wholly offset by a negative step-change in recurrent expenditure
- $5.1 million associated with the completion of the EMR initiatives underway, including the transfer of the system operations functions[114] and associated relocation of staff to the AEMO
- $1.0 million associated with specific charges incurred by the ERA for its technical consultants in relation to AA4 and AA%, which are directly passed through to Western Power.

458. Indirect costs over the AA4 period are forecast to be $815 million, with $189 million forecast to be expensed. This forecast includes a combined negative step change of $92 million driven by efficiencies achieved through the Business Transformation Program and the change in the accounting treatment of operating leases.

459. We commissioned a report from Synergies to provide an assessment of our opex relative to our transmission and distribution electricity network service provider peers. Synergies found that we had improved our performance since 2007, and in particular over the last few years, and noted that our performance was expected to improve further over the AA4 period.

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113 Including $57 million of indirect costs expensed to revenue-cap services.

114 System operations functions were undertaken by System Management as defined in the WEM Rules, a ring-fenced business unit within Western Power. The accountability, staff and assets were transferred to the AEMO in 2016 as part of the EMR.

7.3 Development of the opex forecasts

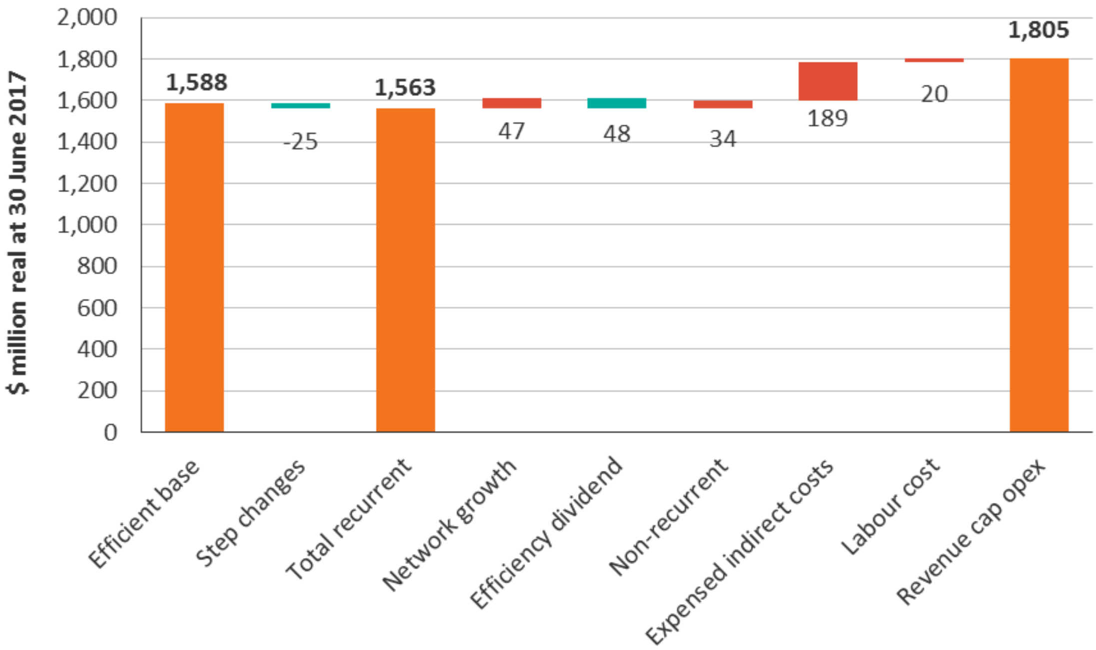
460. Western Power applies a robust governance framework to expenditure. The opex program is revised and updated annually in line with the investment planning cycle, and documented in our Network Management Plan, Network Development Plan and Business Plan. Individual non-recurrent projects and any step changes in recurrent opex are subject to a gated investment governance process. Further information on the governance framework is provided in Attachment 7.2.

461. Opex has been forecast using the base-step-trend method. This method has been applied in recent regulatory decisions in Australia, including Western Power's AA3 decision. Under this method we have applied the following steps:

1. **establish the efficient base year**
   - we have used the 2016/17 actual audited recurrent opex as the base year as this is our most recent year of financials and therefore the best representation of Western Power's actual cost base
2. **adjust for step changes in recurrent opex**
   - we have forecast and adjusted the recurrent base year opex for increases or decreases in costs arising from new or amended obligations and/or activities expected over the AA4 period
3. **trend to account for network growth**
   - we have forecast the growth drivers of opex and added incremental changes in costs associated with servicing a growing network and customer base over the AA4 period and offset it with an efficiency adjustment
4. **adjust for non-recurrent opex**
   - we have forecast and adjusted the opex for changes in costs arising from new or amended obligations and/or activities expected to occur as discrete activities over the AA4 period
5. **escalate for labour costs**
   - we have forecast changes in the cost of labour over the AA4 period and escalated total opex accordingly.

462. Figure 7.3 shows the build-up of the AA4 forecast opex using the base-step-trend method. The values **include expensed indirect cost and labour escalation**.

Figure 7.3: Build-up of AA4 total opex forecasts, $ million real at 30 June 2017



463. Each year Western Power incurs costs that cannot be directly attributed to specific projects but are required to facilitate the delivery of the overall works program. These are referred to as 'indirect costs'. We have used the same base-step-trend method to forecast indirect costs, and then allocated them between opex and capex in accordance with Western Power's Cost and Revenue Allocation Methodology. Indirect costs over the AA4 period are forecast to be $815 million, with $189 million being expensed and the remaining $626 million being capitalised.

464. Table 7.2 shows a summary of forecast opex by cost type.

Table 7.2: Build-up of AA4 total opex forecasts, $ million real at 30 June 2017

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	AA4
Efficient base year	**317.6**	**317.6**	**317.6**	**317.6**	**317.6**	**317.6**	**1,588.0**
Step changes		-5.0	-5.0	-5.0	-5.0	-5.0	-25.0
Total recurrent opex		**312.6**	**312.6**	**312.6**	**312.6**	**312.6**	**1,563.0**
Network growth escalation		2.9	5.9	9.4	12.6	15.7	46.6
Efficiency dividend		-3.2	-6.3	-9.6	-12.8	-16.1	-48.0
Non-recurrent opex		32.5	1.2	0.2	-	0.5	34.4
Expensed indirect costs		40.0	36.8	33.3	39.4	39.5	189.0
Labour cost escalation		1.4	2.4	3.7	5.4	7.1	20.0
Regulated revenue cap opex		**386.4**	**352.5**	**349.7**	**357.2**	**359.3**	**1,805.1**

7.4 Establishing the efficient base year

465. Western Power's estimated recurring opex for 2016/17 is $318 million. This includes $182 million of recurring opex on the distribution network, $53 million of recurring opex on the transmission network, and $83 million of recurring corporate opex.

466. The efficient base year has been determined by adjusting the 2016/17 regulated financial statement actual opex for the following items:

- **Removal of non-revenue cap services**

  Western Power's non-revenue cap services are forecast independently and are not required to be approved by the ERA.

  The 2016/17 actual opex amount includes $17 million[115] of non-revenue cap services expenditure. This has been removed from the recurrent base year.

- **Removal of Business Transformation Program costs**

  During the AA3 period, Western Power commenced its Business Transformation Program to challenge the status quo, reduce the costs of operating the network, and improve rigour around investment activities. We specifically targeted efficiencies that would reduce recurring opex, recognising it will help reduce our customers' electricity bills over future access arrangements.

  The 2016/17 actual opex includes $56 million of **costs** associated with the Business Transformation Program, which have been removed from the recurrent base year. We have then included a non-recurrent expenditure forecast for 2017/18 to complete the Business Transformation Program (see section 7.7).

- **Removal of EMR costs**

  During the AA3 period, Western Power undertook a significant amount of work to facilitate the EMR. This work included amongst other things:

  – providing information to and making submissions on the Public Utilities Office's position papers and proposed legislative amendments

  – preparing for the transition to the national regulatory framework and commencement of our first regulatory pricing submission to the AER

  – developing network limitation equations to underpin the development of the constrained electricity flow model.

  The 2016/17 actual opex includes $15 million of costs associated with the EMR, which have been removed from the recurrent base year. These costs are not recurrent in nature, and the EMR is now largely complete. We have included a non-recurrent expenditure forecast for 2017/18 and 2018/19 to complete the transfer of the system operations function to the AEMO (see section 7.7).

- **Mid-West Energy Project provision reversal**

  The $363 million Mid-West Energy Project involved construction of a 200 km transmission line from Perth to the mid-west of WA, a 70 km line to an iron ore mine, and upgrades to several substations. The works were completed in March 2015. In June 2015, a $6 million opex provision was raised to allow for the finalisation of the contract. When the final reconciliation of costs

115 Including the indirect cost allocation to non-revenue cap services.

payable under the contract was completed in March 2017, Western Power determined that the costs should be capitalised against the asset, rather than expensed.

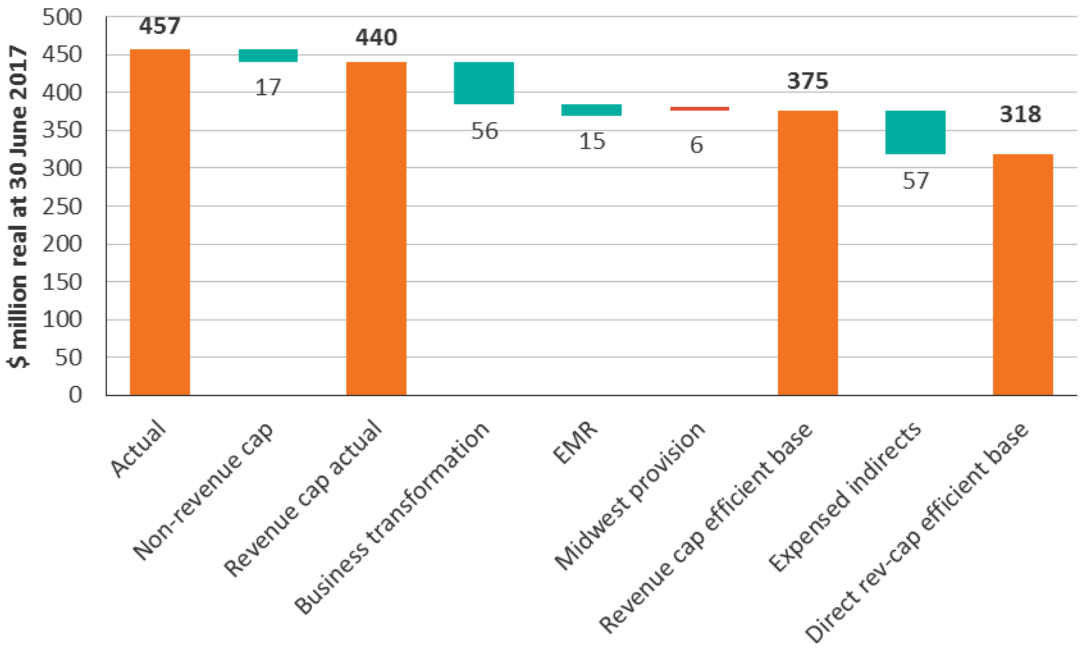
The 2016/17 actual opex includes a $6 million credit associated with the project cost that was ultimately expensed. This has been removed from the recurrent base year.

- **Removal of indirect costs**

  The 2016/17 actual opex amount includes $57 million of expensed indirect costs. We have removed these from the recurrent base year. This is because we forecast indirect costs separately and then allocate them between capex and opex activities (to leave indirect in the base year would result in a double count). The forecasting approach for indirect costs is discussed in section 7.9.

467. Figure 7.4 shows the adjustments from the 2016/17 regulated financial statements to determine the efficient base year.

Figure 7.4: Determination of efficient base year



7.4.1.1 Inclusions in the efficient base year

468. Recurrent opex includes all the ongoing and business as usual costs of providing covered services. The majority of recurring opex during 2016/17 (74 per cent) was for the recurrent operating and maintenance activities that Western Power undertakes to meet service standard and compliance obligations. The remaining share was driven by corporate costs such as insurance, rates and taxes.

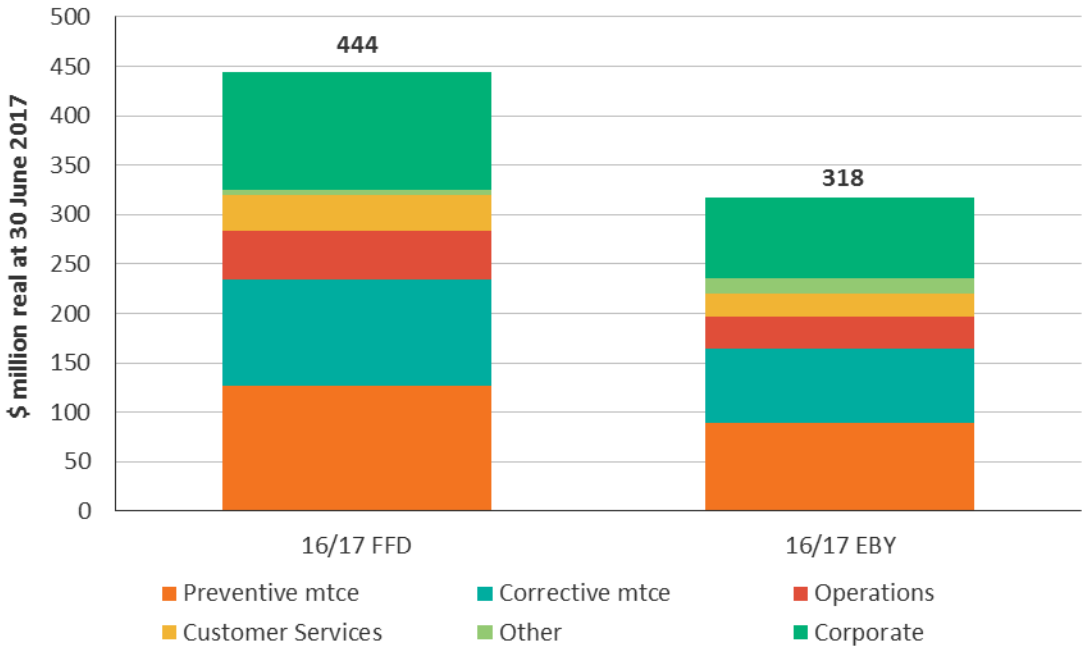
469. During 2016/17, Western Power's $318 million efficient recurring operating costs comprised:

- **recurrent network costs** ($235 million), including:
  - **preventative maintenance** ($89 million) – to maintain our assets across their expected lives and network performance through the proactive inspection and identification and treatment of poor performing assets that are likely to fail

   - **corrective maintenance** ($75 million) – to rectify unsafe conditions arising from extreme weather events, ageing assets, failed assets and other reactive events
   - **operations** ($33 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** ($24 million) – to maintain service to customers through our call centre, billing services, and repair and maintenance of meters
   - **other** ($15 million) – primarily for works required at the initiation stage to identify network issues and determine high level solutions. This includes developing annual load forecasts, exploring emerging technologies, non-network solutions development and creating new standards and policies
- **corporate costs** ($83 million)
   - to provide recurrent administrative activities and business support functions to run the business (including insurance, rates, taxes and Government payments).

470. Western Power's efficient base year is 28 per cent lower than the 2016/17 recurrent opex forecast approved by the ERA in its AA3 further final decision. Figure 7.5 compares the $444 million forecast efficient level of recurrent opex for 2016/17 approved by the ERA in its further final decision[116] to the $318 million 2016/17 efficient base year.

Figure 7.5: Efficient base year compared to AA3 further final decision, $ million real at 30 June 2017



116 In its AA3 proposal, Western Power forecast the majority of its opex using a roll-forward method similar to the base-step-trend method. However, the forecasts associated with a number of activities were individually forecast as non-recurrent costs and added separately. In the AA4 period, we have assessed these costs as recurrent, and have therefore included them in the base year. For the purposes of this comparison, we have treated the AA3 costs in the same manner as the proposed AA4 costs. The '16/17 FFD' recurrent opex number therefore does not align to the AA3 further final decision, but the underlying opex values do.

7.4.1.2 Why the base year is efficient

471. The base year is efficient as it incorporates the benefits of the Business Transformation Program and reflects the lowest sustainable recurrent cost of providing covered services.

472. The Business Transformation Program was Western Power's response to the changes that have occurred in the energy market over the AA3 period. At the beginning of the AA3 period (2012/13) substantial demand growth was forecast, and Western Power's operating and maintenance program was designed to support a growing network providing electricity to a growing customer base.

473. Over the course of the period, a combination of factors including WA's economic slowdown, impact of new technologies, and changing customer behaviour, meant forecast growth did not materialise.

474. Rather than assume the operating and capital expenditure program developed as part of the AA3 review process would remain the optimal approach for the period, we reconsidered our plans in line with customers' expectations, and accelerated our business improvement plans.

Figure 7.6: Factors influencing Western Power's Business Transformation Program

475. At the beginning of the AA3 period we commenced a program of operating cost reviews, looking at our organisational model undergoing an internal restructure in 2012 and 2013. This ongoing business review continued, gathering pace in 2014 as economic conditions slowed and State Government-led reforms emerged. The efficiency drive resulted in the implementation of the Western Power's Business Transformation Program, which commenced in 2015.

476. The Business Transformation Program has delivered $330 million of recurrent cost savings as at 30 June 2017:

- $207 million of capex
- $72 million of opex
- $51 million of indirect cost efficiencies.

477. The 2016/17 efficient base year amount incorporates efficiencies[117] of $60 million in opex savings and $43 million of indirect cost savings resulting from improvements to Western Power's asset strategies, procurement processes, work practices and organisational structure.

117 These efficiencies are additional, as the savings from 2015/16 are already included in the recurrent 2016/17 base year.

478. Improvements to Western Power's asset strategies, procurement processes, and work practices mean we have rationalised our operating costs to a point where we expect to be able to maintain current service levels in a more cost effective way during the AA4 period.

479. An example of a Business Transformation Program initiative that has reduce our opex is provided in Box 1.

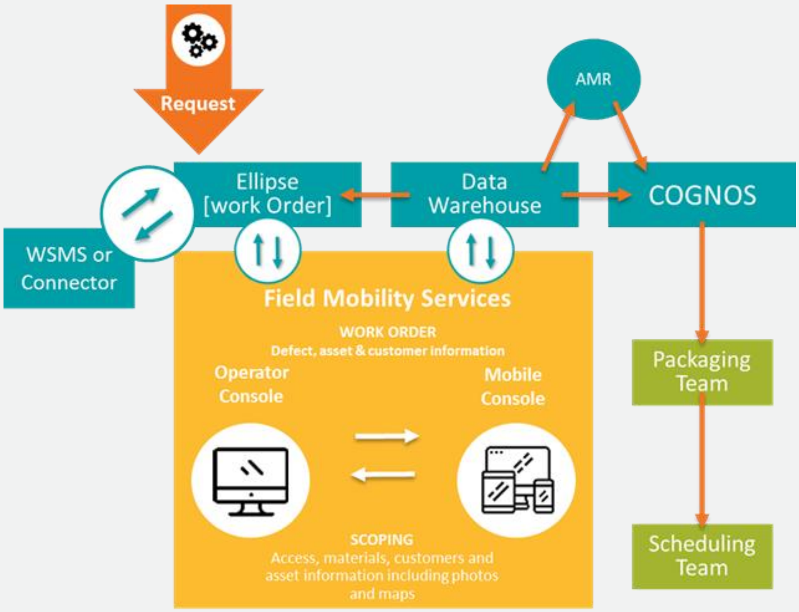
Box 1: Automated scoping solution

In March 2017, Western Power implemented an automated solution for distribution volumetric programs of work – the **Field Mobility Services** (**FMS**) system– to replace the current manual process.

The role of field scopers is to undertake an on-site assessment of the work required to fix a network asset. This includes the collection of information about the site and access, customer information, materials and any specialised plant required.

The previous manual process required the scoper to complete a non-standardised paper assessment and return it from the field for manual data input before the work was scheduled for execution.

The new automated solution provides access to standard scripts and electronic forms, with an ability to wirelessly transmit the information including site photos.



This initiative has proved a success in reducing time in the field and providing better quality information that is 'near real time' and more accessible and has resulted in:

- near real time data delivery from our systems to and from the field
- reduced scheduling time from around two weeks to two days
- increased efficiency of our field staff by scoping works related to adjacent assets and action variation requests in near real time.

The new automated process will allow our scoping team to increase the number of jobs from 10,000 jobs in 2016/17 to 15,000+ jobs for 2017/18.

7.5 Adjusting for recurrent step changes

480. We have removed a further $25 million in recurrent opex from our opex forecasts in specific years of the AA4 period.

481. We have applied a $5 million step change from 2017/18 associated with Business Transformation Program initiatives that were not completed prior to the start AA4 period (1 July 2017). These initiatives include:

- **updating our vegetation management strategy** – we expect to be able reduce the cost of vegetation management by introducing a risk-based approach, including investigation of alternative vegetation management practices and treatment options
- **reducing unplanned overtime** – we expect to be able to improve systems and processes governing when overtime is approved when responding to network faults.

Table 7.3: Recurrent step changes, $ million real at 30 June 2017

Year	Value per annum	Description
2017/18	-5.0	Efficiencies resulting from outstanding Business Transformation Program initiatives.
Total value of step changes	**-25.0**	

7.6 Trending the base year

482. Base year recurrent opex is escalated by forecast growth in the customer base and the physical size of the transmission and distribution networks. This is wholly offset by the one per cent per annum efficiency adjustment we have applied over the AA4 period.

483. As discussed in Chapter 6, Western Power expects minimal overall network growth over the AA4 period. Despite flat forecast peak demand, we have identified pockets of growth in some areas[118], which will drive our transmission network investment over the next 10 years.

484. In determining network growth, Western Power has used the prevailing best practice methodology employed by other Australian distribution and transmission electricity network service providers[119]. While the general principle is the same as that used for Western Power's AA3 submission, the methodology has matured since our AA3 submission, to:

- apply different network factors than the AA3 methodology, including determining separate growth factors for transmission and distribution

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118 The Mandurah, Waikiki, Ellenbrook and Bunbury areas in particular are expected to experience steady growth in peak demand.

119 The network growth methodology and current weighting factors are consistent with recent AER decisions. See for example, pages 17-18 *Draft Decision Powerlink transmission determination 2017-18 to 2021-22 - Attachment 7 – Operating Expenditure*, AER, September 2016.

- apply a weighting system, where the overall growth reflects a weighted average of the various network factors to better reflect opex drivers rather than the straight average employed previously.

485. The transmission network growth factors, weightings and the resulting weighted average growth rate are provided in Table 7.4. These are applied to all transmission opex categories.

Table 7.4: Transmission network growth factors, per cent per annum

	Weighting	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Circuit length	28.7	0.32	0.33	0.22	0.33	0.32	0.30
Ratcheted max. demand	22.1	0.00	0.00	0.00	0.00	0.00	0.00
Energy delivered	21.4	0.30	0.00	2.89	2.50	0.00	1.14
Weighted entry and exit conn. point	27.8	-0.24	-0.7	-0.25	-0.98	0.00	-0.44
Transmission network growth	**100.0**	**0.09**	**-0.11**	**0.62**	**0.35**	**0.09**	**0.21**

486. The transmission network growth factors are defined below.

- **Transmission circuit length**

  This is the length (measured in kilometres) of lines in service (the total length of lines including interconnectors, backbones and spurs). A double circuit line counts as twice the length. Length does not take into account vertical components such as sag.

  The length of customer driven transmission lines to be installed is difficult to forecast accurately, and therefore, Western Power uses an estimate of the proportion of customer lines installed during the AA3 period to forecast this component of transmission forecast line length growth.

  An estimate of transmission lines expected to be removed during the AA4 period is then deducted from the forecast, and an estimate of transmission lines to be installed due to capacity expansion is added to the forecast.

- **Ratcheted transmission maximum demand**

  This is the annual average growth in the highest maximum demand on the transmission network. Growth is calculated as the difference between the highest maximum demand that has ever occurred and the highest maximum demand that is forecast. Where the future maximum demand is lower than historical maximum demand, the growth factor would be zero.

  The highest maximum demand that has occurred on the transmission network was 3,878 MW in 2015/16. Forecast maximum demand over the AA4 period is lower than this figure.

- **Transmission energy delivered**

  This is the annual average growth in energy volumes expected to be delivered over the AA4 period, as forecast in Western Power's 2017 Energy and Customer Numbers Forecast report (see Attachment 7.3).

- **Weighted entry and exit transmission connection points**

  This is the annual average growth in the number of entry and exit points on the transmission network, measured as the total transmission node identifiers at each voltage level, weighted by the voltage level.

487. The distribution network growth factors, weightings and the resulting weighted average growth rate is provided in Table 7.5. These weightings are applied to all distribution opex categories.

Table 7.5: Distribution network growth factors, per cent per annum

	Weighting	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Customers	67.6	1.65	1.73	1.69	1.66	1.63	1.67
Circuit length	10.7	0.91	0.91	0.91	0.91	0.91	0.91
Ratcheted max. demand	21.7	0.00	0.00	0.00	0.00	0.00	0.00
Distribution network growth	**100.0**	**1.21**	**1.26**	**1.24**	**1.22**	**1.20**	**1.23**

488. The distribution network growth factors are defined below.

- **Distribution customer numbers**

  This is the annual average growth in customer numbers over the AA4 period as forecast in Western Power's 2017 Energy and Customer Numbers Forecast report (see Attachment 7.3).

- **Distribution circuit length**

  This is the annual average growth in the length of distribution lines (where each single wire earth return line, single-phase line and 3 phase line counts as one line). The length of customer driven distribution lines to be installed is difficult to forecast accurately, and therefore, Western Power uses an estimate of the proportion of customer lines installed during the AA3 period to forecast the AA4 line length growth.

- **Ratcheted distribution maximum demand**

  This is the annual average growth in the highest maximum demand on the distribution network. Growth is calculated as the difference between the highest maximum demand that has ever occurred and the highest maximum demand that is forecast. Where the future maximum demand is lower than historical maximum demand, the growth factor would be zero.

  The highest maximum demand that has occurred on the distribution network was 3,552 MW in 2015/16. Forecast maximum demand over the AA4 period is lower than this figure.

489. The network growth percentage applied to corporate costs is a weighted average of the distribution and transmission network growth factors. The weighting is based on the allocation of our corporate opex to distribution and transmission in accordance with the Cost and Revenue Allocation Methodology and reflected in the 2016/17 Regulated Financial Statements (73 per cent and 27 per cent respectively).

490. The weightings and resulting network growth factors are shown in Table 7.6.

Table 7.6: AA4 corporate network growth, per cent

	Weighting	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Distribution network growth	**73.2**	1.21	1.26	1.24	1.22	1.20	1.23
Transmission network growth	**26.8**	0.09	-0.11	0.62	0.35	0.09	0.21
Corporate network growth	**100.0**	**0.91**	**0.90**	**1.08**	**0.99**	**0.91**	**0.96**

491. This methodology has resulted in the total opex network growth escalation forecast of $47 million, as shown in Table 7.7.

Table 7.7: AA4 total opex network growth escalation, $ million real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Opex network growth escalation	2.9	5.9	9.4	12.6	15.7	46.6

492. In accordance with the base-step-trend methodology, we expect, and therefore are offering reductions in our opex reflecting improvements in productivity. We have applied a one per cent per annum negative adjustment. This has reduced our opex forecasts by $48 million over the AA4 period, and wholly offsets the forecast network growth escalation.

493. This is based on Western Power's expectations of the additional cost savings we may be able to achieve, and is in addition to the included reduction in forecast opex of $512 million[120] over the AA4 period resulting from the:

- reduced 2015/16 recurring opex savings of $12 million which in turn lowered our 2016/17 opex
- reduced 2016/17 base year, which included further opex efficiencies of $60 million
- forecast recurrent step change of $5 million from 2017/18.

494. The forecast productivity gains are passed through to our customers as savings and reflect our commitment to manage our operating expenditure so that it remains flat over the AA4 period.

495. Table 7.8 shows the opex efficiencies applied to our opex forecast.

Table 7.8: Opex efficiencies applied in AA4, $ million real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Opex efficiencies (% p.a. / CAGR)	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
Opex efficiencies	-3.2	-6.3	-9.6	-12.8	-16.1	-48.0

120 Our opex forecast would have been $512 million higher than we have proposed over the five years of the AA4 period if the recurrent efficiencies to-date had not been realised. This does not include the expensed proportion of our total indirect costs, which would have been a further $82 million higher (see section 7.9).

7.7 Adjusting for non-recurrent opex

496. Western Power forecasts it will spend $34 million of non-recurrent opex during the AA4 period. This includes:

- $28 million associated with the completion of the Business Transformation Program in 2017/18
- $5 million associated with the transfer of system operations functions and associated relocation of staff to the AEMO under the EMR in 2017/18
- $1 million associated with the costs incurred by the ERA for its review of Western Power's AA4 and AA5 submissions.

497. These costs are provided by year in Table 7.9 and discussed in each of the following sections.

Table 7.9: Summary of AA4 non-recurrent costs by activity, $ million real at 30 June 2017

Category	Activity	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Corporate	Business Transformation Program	28.3	-	-	-	-	**28.3**
Corporate	EMR program	3.7	1.2	0.2	-	-	**5.1**
Corporate	ERA regulatory costs	0.5	-	-	-	0.5	**1.0**
Total non-recurrent		**32.5**	**1.2**	**0.2**	**-**	**0.5**	**34.4**

7.7.1 Business Transformation Program

498. Western Power forecasts it will spend $28.3 million to complete the Business Transformation Program.

499. The Business Transformation Program is due to be completed in 2018. Western Power has forecast it will spend $28.3 million in opex in 2017/18 to complete the delivery of the program to deliver significant capex and opex savings across the business.

500. As discussed in section 7.4, to-date we have found $72 million of opex efficiencies in the AA3 period, and removed a further $5.0 million from the base year to reflect what we consider is an efficient amount of opex. The program has also resulted in $51 million of indirect cost efficiencies in the AA3 period. Our indirect costs will be further reduced by $12.0 million (see section 7.9).

501. The success of our Business Transformation Program relies on the completion of several critical initiatives in the AA4 period, including:

- **restructuring areas of the business** – we expect to be able to drive increases in productivity and reductions in employee expenses through a combination of outsourcing and automating manual processes associated with commercial, finance and risk functions
- **standardising depot and crew tasks** – we expect to be able to reduce costs by improving depot and field crew efficiency through standardising and streamlining tasks
- **enhancing forecasting processes –** we expect to be able to rationalise our business planning and reporting functions by streamlining processes, increasing the integration of our systems and manual processes, and increasing our reliance on ICT self-service models

- **network outages** – we will be launching a new streamlined and automated planned outage notification system which will transform the way we schedule and manage network outages
- **HR solutions centre** – we have now launched the self-service portal whereby employees have access to more automated information and online processing which has increased efficiencies across all areas of the business.

7.7.2 EMR program

502. Western Power forecasts it will spend $5 million on the transfer of system operations functions to the AEMO.

503. As part of the EMR, the State Government decided to transfer system operations functions from Western Power to the AEMO to improve the coordination of system operations (including generator dispatch) with the commercial outcomes of the WEM. The necessary legislative amendments including changes to the *Electricity Industry (Wholesale Electricity Market) Regulations 2004* and associated WEM Rules were gazetted on 30 May 2016, and the transfer took effect from 1 July 2016.

504. Over the past year, Western Power has been working with the AEMO to transition the staff physically from the network control centre in East Perth to the AEMO's new offices.[121] This transition will involve:

- the physical relocation of approximately 30 staff from the network control centre in East Perth to the AEMO's office in the Perth CBD
- the transfer of IT systems from Western Power to the AEMO including costs associated with the transfer of records, changes to systems access and solutions testing.

505. The EMR program costs also include the costs associated with the development of technical equipment limit equations to model the impact of network constraints on power system flows and the dispatch of generation facilities in the WEM. This is required due to the new split of functions between our network controllers, and the AEMO's system controllers, as well as the move to a constrained network model.[122]

7.7.3 ERA regulatory costs

506. Western Power forecasts it will spend an additional $1 million to fund the ERA's costs related to the AA4 and AA5 review processes.

507. On 10 October 2012, the State Government introduced the *Economic Regulation Authority (Electricity Networks Access Funding) Regulations 2012* which would require Western Power to pay for the ERA's costs in relation to its electricity access functions. This includes standing charges in relation to the ERA's business as usual costs, as well as specific charges directly passed through to Western Power for its technical consultants in relation to the access arrangement review. As the legislative change were not in force at the time the ERA incurred its AA3 costs, Western Power did not include specific charges in its AA3 submission.

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121 The AEMO moved its market operations staff in August 2017 from 197 St Georges to Central Park. The transfer of system operations staff to the same location will occur in December 2017.

122 The costs included in our forecasts do not include modelling the constraints on power flows across the whole network. They only include those required to enable the connection and dispatch of generators in the competing applications groups (see Chapter 8).

508. We have included a forecast of $0.5 million per access arrangement review as an estimate of the costs the ERA is likely to incur.

7.8 Escalating for labour costs

509. Labour cost escalation is forecast to grow by an average of 1 per cent per annum and contributes $20 million to opex forecasts over the AA4 period. The labour cost component[123] of the opex forecast is escalated by the forecast annual rate of growth in the wage price index for WA electricity, gas, water and waste water services.

510. This is consistent with our approach in AA3 and the method of escalation adopted by all other Australian regulated energy businesses.

511. Western Power calculates the labour cost component as the average proportion of labour costs in relation to total spend over the last two years. Labour costs are 40 per cent of total opex.

512. Table 7.10 shows the labour cost escalation rates applied to labour opex costs and the labour cost escalation forecast for the AA4 period:

Table 7.10: Labour cost escalation, $ million real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Real wage price growth (% p.a. / CAGR)	0.9	0.8	1.0	1.1	1.2	1.0
Labour cost opex	**1.4**	**2.4**	**3.7**	**5.4**	**7.1**	**20.0**

513. Our wage price growth forecasts are lower than historical Australian wages growth as shown in Figure 7.7.

123 This includes internal labour and embedded contractors.

Figure 7.7: Australian wages growth, electricity gas and waste water services and all industries

514. Further detail on labour cost escalation factors is provided in Synergies' expert report provided at Attachment 7.4.

7.9 Indirect costs

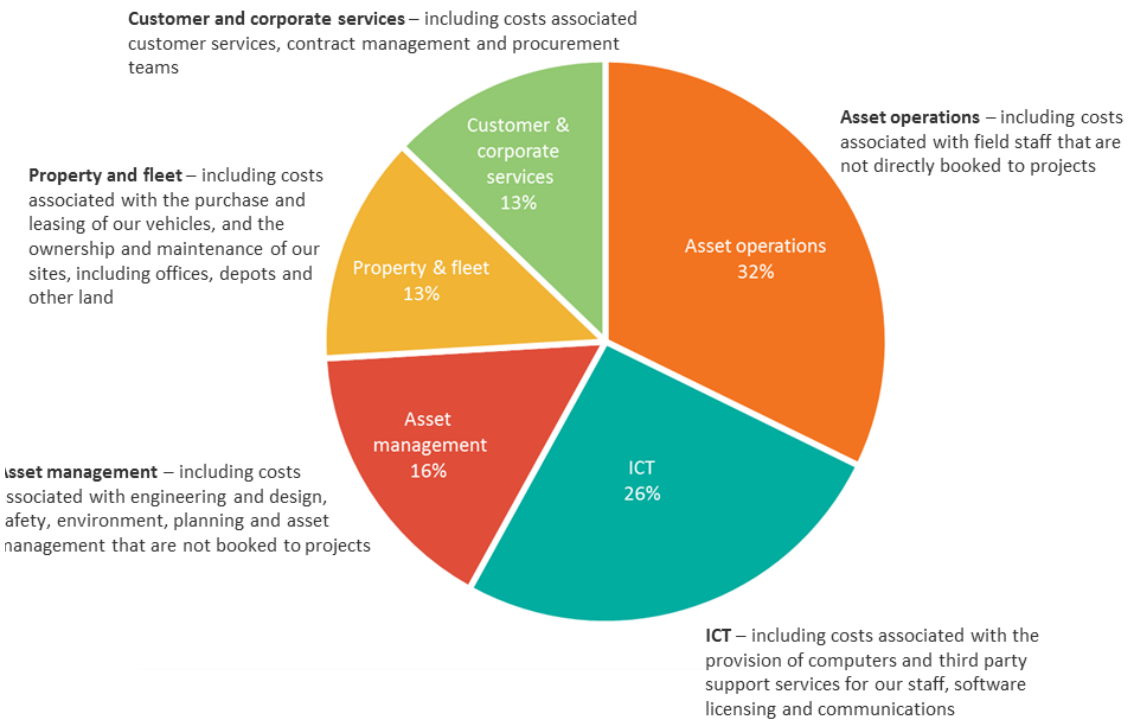
515. Western Power incurs costs that are not directly related to the network works program but are required to facilitate the delivery of the overall works program. These are called indirect costs. Indirect costs include project management and coordination, as well as maintaining computers and facilities for operational staff.

516. Western Power forecasts it will spend $815 million[124] on indirect costs over the AA4 period. This includes $189 million being expensed and the remaining $626 million being capitalised.

517. The breakdown of total indirect costs is shown in Figure 7.8.

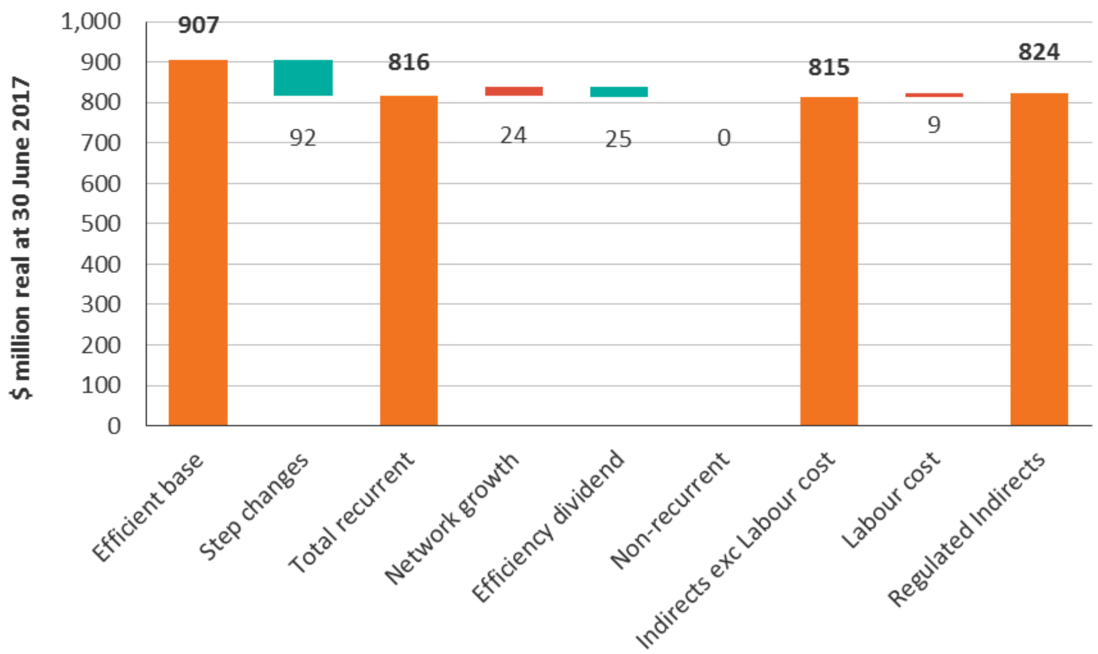
124 This excludes labour cost escalation. Total indirect costs including labour cost escalation is $824 million, as shown in Figure 7.9.

Figure 7.8: Breakdown of indirect costs



518. Figure 7.9 shows the build-up of the AA4 forecast indirect costs using the base-step-trend method.

Figure 7.9: Build-up of AA4 total indirect cost forecasts, $ million real at 30 June 2017



519. These costs are then allocated to all activities that attract indirect costs, as per Western Power's Cost and Revenue Allocation Methodology (see Attachment 7.1). This results in a portion of the costs being capitalised and the remainder expensed.

520. Table 7.11 shows the indirect costs applied to our expenditure program.

Table 7.11: AA4 indirect costs, $ million real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Capitalised indirect costs	129.2	132.4	125.5	119.4	119.1	625.6
Indirect costs expensed to revenue-cap services	40.0	36.8	33.3	39.4	39.5	189.0
Total indirect costs	**169.3**	**169.1**	**158.8**	**158.8**	**158.6**	**814.6**

7.9.1 Developing the indirect cost forecast

521. Western Power has forecast indirect costs separately from direct opex, however, the same base-step-trend method has been applied. Note that due to the nature of the cost component, Western Power's indirect costs are largely fixed and do not fluctuate significantly in relation to the works program.

522. Table 7.12 provides a summary of the various components of the build-up of the indirect cost forecast.

Table 7.12: Build-up of AA4 total indirect cost forecasts, $ million real at 30 June 2017

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Efficient base year	181.4	181.4	181.4	181.4	181.4	181.4	907.1
Step changes		-12.0	-12.0	-22.5	-22.5	-22.5	-91.5
Total recurrent opex		**169.4**	**169.4**	**158.9**	**158.9**	**158.9**	**815.6**
Network growth escalation		1.6	3.2	4.7	6.4	7.9	23.7
Efficiency dividend		-1.7	-3.4	-4.9	-6.5	-8.2	-24.7
Non-recurrent opex		-	-	-	-	-	-
Indirect costs excl. labour cost escalation		**169.3**	**169.1**	**158.8**	**158.8**	**158.6**	**814.6**
Labour cost escalation		0.6	1.2	1.7	2.4	3.2	9.1
Total regulated revenue-cap indirect costs		**169.9**	**170.3**	**160.5**	**161.2**	**161.8**	**823.7**

7.9.2 Establishing the efficient base year

523. We have used 2016/17 as the base year to calculate our indirect costs.

524. The 2016/17 indirect cost value included $51 million of indirect cost savings as a result of Business Transformation Program initiatives over the AA3 period.

7.9.3 Adjusting for recurrent step changes

525. Western Power has identified recurrent step changes to indirect cost components that will reduce overall indirect costs by $92 million over the AA4 period. These are shown in Table 7.13.

Table 7.13: Indirect recurrent step changes, $ million real at 30 June 2017

Year	Value per annum	Description
2017/18	-12.0	Efficiencies[125] related to productivity gains and reductions in indirect costs through a combination of system enhancements and process improvements associated with Asset Management, Asset Operations, Finance and Customer and Corporate Services.
2019/20	-10.5	Reduction due to the change in the accounting treatment of operating leases to require them to be capitalised from 2019/20. This will result in a commensurate increase in our capex requirement (see Chapter 8).
Total value of step changes	**-91.5**	

7.9.4 Trending the base year

526. Base year indirect costs are escalated by forecast growth in the customer base and the physical size of the transmission and distribution networks. We have used the same network growth factors for transmission and distribution as those used to escalate the opex forecasts.

527. We have applied a weighted network growth factor to indirect costs based on the proportion of pre-escalated distribution and transmission total AA4 expenditure that attracts indirect costs. This has resulted in a compound annual growth rate of 0.97 per cent over AA4.

528. The network growth escalation is wholly offset by our proposed efficiency adjustment of one per cent per annum which we are also applying to our indirect cost base.

529. This methodology has resulted in the total indirect cost network growth escalation forecast of $24 million and an efficiency adjustment of -$25 million, as shown in Table 7.14.

Table 7.14: AA4 total indirect cost network growth escalation and efficiencies, $ million real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Indirect network growth (% p.a. / CAGR)	0.93	0.92	1.09	1.01	0.92	0.97

125 This is in addition to the $51 million in efficiencies realised in AA3 and included in our 2016/17 base year. Our opex forecast would have been $268 million higher without the Business Transformation Program. $82 million of this would have been expensed and $186 million capitalised.

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Indirect cost network growth escalation	**1.6**	**3.2**	**4.7**	**6.4**	**7.9**	**23.7**
Indirect efficiencies (% p.a. / CAGR)	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
Indirect efficiencies	**-1.7**	**-3.4**	**-4.9**	**-6.5**	**-8.2**	**-24.7**

7.9.5 Adjusting for non-recurrent indirect costs

530. Western Power has not identified any non-recurrent indirect cost step changes over the AA4 period.

7.9.6 Escalating for labour costs

531. The labour cost component[126] of the indirect cost forecast is escalated by the forecast annual rate of growth in the wage price index for WA electricity, gas, water and waste water services. We calculate the labour cost component as the average proportion of labour costs in relation to total spend over the last three years. Labour costs are 40 per cent of total indirect costs.

532. We have applied the same forecast annual rate of growth in the wage price index for WA electricity, gas, water and waste water services to the labour cost component of our forecast indirect costs to that used in our opex forecasts. This methodology results in the total indirect labour cost escalation forecast of $9 million, as shown in Table 7.15.

Table 7.15: AA4 total indirect cost labour cost escalation, $ million real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Real wage price growth (% p.a. / CAGR)	0.9	0.8	1.0	1.1	1.2	1.0
Indirect cost labour cost escalation	**0.6**	**1.2**	**1.7**	**2.4**	**3.2**	**9.1**

7.9.7 Total expensed indirect costs

533. Western Power has forecast $189 million of expensed indirect costs over the AA4 period, allocated between transmission, distribution and corporate expenditure categories, as shown in Table 7.16.

126 This includes internal labour and embedded contractors.

Table 7.16: AA4 expensed indirect costs, $ million real at 30 June 2017[127]

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Transmission	9.9	9.0	8.1	9.6	9.5	**46.2**
Distribution	30.1	27.7	25.2	29.8	30.0	**142.8**
Corporate	-	-	-	-	-	**-**
Total indirect costs expensed to revenue cap services	**40.0**	**36.8**	**33.3**	**39.4**	**39.5**	**189.0**

7.10 Total opex forecast

534. Table 7.17 shows a summary of Western Power's forecast operating expenditure by category.

Table 7.17: Summary of AA4 opex by expenditure category, with escalations and indirect costs applied, $ million real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Transmission						
Operations	14.5	14.2	14.1	14.3	14.2	**71.3**
Maintenance	42.5	41.6	41.0	42.0	41.8	**208.9**
Other	6.0	5.9	5.8	5.9	5.9	**29.4**
Total transmission opex	**63.0**	**61.7**	**60.8**	**62.2**	**62.0**	**309.6**
Distribution						
Operations	21.0	21.1	21.1	21.4	21.6	**106.2**
Maintenance	149.9	148.6	147.3	152.2	153.3	**751.4**
Customer service and billing	25.1	25.2	25.2	25.6	25.8	**126.9**
Other	12.0	11.8	11.7	12.1	12.2	**59.8**
Total distribution opex	**208.0**	**206.7**	**205.4**	**211.3**	**212.9**	**1,044.3**
Corporate						
Business support	115.4	84.1	83.5	83.7	84.5	**451.2**
Total corporate opex	115.4	84.1	83.5	83.7	84.5	451.2

127 Excluding real cost escalation.

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Total regulated revenue-cap opex	**386.4**	**352.5**	**349.7**	**357.2**	**359.3**	**1,805.1**

535. Further information is provided in Confidential Attachment 7.5.

7.11 Benchmarking our opex costs

536. Western Power engaged Synergies to assess the efficiency of our forecast opex and capex for the AA4 period. Synergies used benchmarking techniques[128] adopted by other Australian regulated energy businesses. Specifically, Synergies analysed our productivity performance compared to other distribution and transmission network service providers in Australia, which are part of the NEM.[129]

537. The top-down measures of productivity performance that Synergies has used are:

- Multilateral total factor productivity (**MTFP**) index number scores, as well as the associated capex and opex partial factor productivity (**PFP**) scores;
- stochastic frontier analysis (**SFA**) model used to assess DNSPs' base year opex for forecasting purposes complemented by the following econometric benchmarking techniques:
  - Cobb-Douglas SFA
  - Translog least squares
  - Cobb-Douglas least squares.

538. In addition, Synergies has undertaken an assessment of Western Power's distribution opex productivity applying the data envelope analysis (**DEA**) benchmarking technique. The DEA results provide a useful cross-check of the SFA results and opex partial factor productivity results, recognising that:

> *no economic benchmarking technique is overwhelmingly better that any other and that each has its strengths and weaknesses.*[130]

7.11.1 Our distribution opex performance in comparison

539. As shown in Figure 7.10, Western Power's opex productivity has improved over the period, resulting in a move from the 5th to 4th ranked electricity distribution network business in our comparable peer group. Our performance has continued to improve since 2012, except in 2015/16. This is because our opex included the cost of our extensive Business Transformation Program. These costs were once-off and will not be reflected in in the AA4 period.

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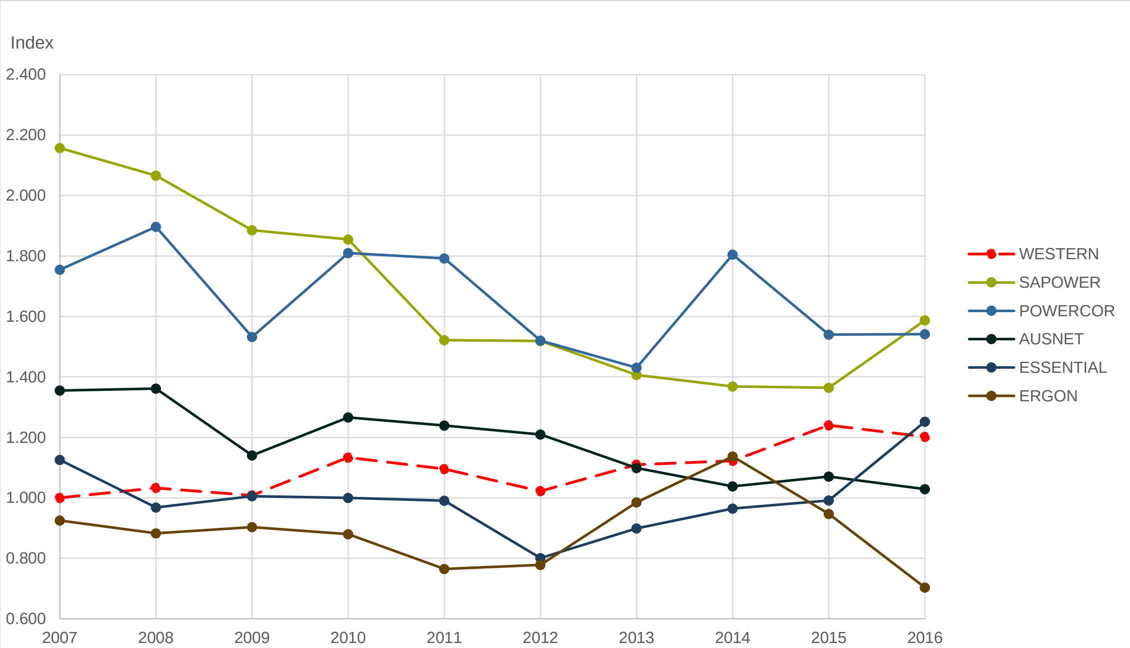
128 Synergies has adopted Economic Insights' preferred MTFP model formulation as of July 2014.

129 Including ActewAGL, TasNetworks, Ausgrid, CitiPower, Endeavour Energy, Energex, Ergon Energy, Essential Energy, Jemena, Powercor, SA Power Network, AusNet, United Energy, ElectraNet, Powerlink and Transgrid.

130 Page 15, *Western Power's Productivity Performance*, Synergies Economic Consulting, September 2017.

Figure 7.10: Distribution opex PFP results for Western Power's closest peers, 2007 to 2016

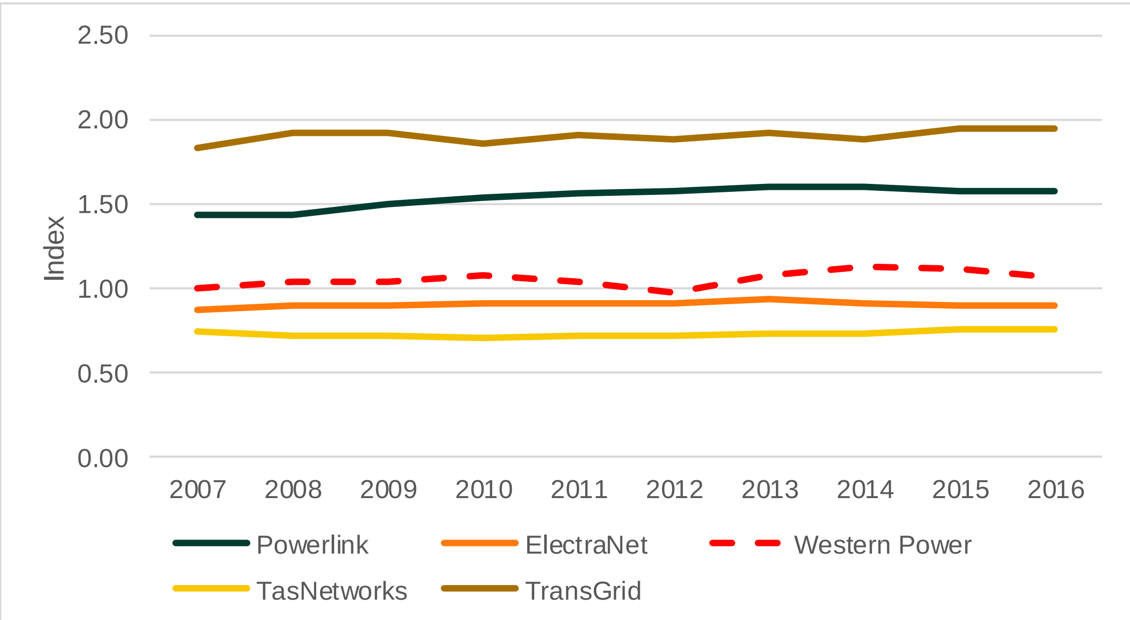


540. We have included an efficiency factor in our distribution opex forecast, and have proposed changes that should maintain the incentives under the GSM to continue to find efficiencies (see Chapter 6). As such, we expect to continue on our increasing trajectory over the AA4 period.

7.11.2 Our transmission opex performance in comparison

541. As shown in Figure 7.11, our transmission opex productivity performance has been relatively flat over the period, consistent with other transmission businesses

Figure 7.11: Transmission opex partial total factor productivity performance



7.11.3 Overall opex performance in comparison

542. In summary, the report shows Western Power's operating costs are efficient and comparable to other Australian electricity networks businesses.

543. Synergies uses a 'rule of thumb' measure whereby a 20 per cent reduction in opex from the five year average[131] would result in a 20.8 per cent increase in opex PFP. Our forecasts show that we expect to achieve a reduction of around 20 per cent by 2017/18 (not including the Business Transformation Program costs).

544. It should be noted that, while the benchmarking report is a useful tool to test whether Western Power's operating costs are reasonable, benchmarking against other networks has not formed the basis of our expenditure forecasts. Our operating costs have been developed using the base-step-trend method and are based on the efficient costs of operating and maintaining the Western Power transmission and distribution networks.

545. Given the unique nature of Western Power's structure and operating environment, (for example the definitions of transmission and distribution are different in the WA framework to those in the NEM, and the isolated nature of the Western Power Network with no interstate backup interconnectors) it is difficult to compare Western Power's costs with a high degree of accuracy. Western Power submits that while benchmarking is useful as a method of 'sanity checking' expenditure forecasts, it should not be exclusively used as a tool to determine efficient operating costs.

546. While comparisons with other network operators has been used as a way of setting aspirational targets for the Business Transformation Program, we have placed little weight on using benchmarking to establish our ongoing operating costs.

131 Calculated as the average of the nominal opex five financial years to 30 June 2016.

8. Forecast capital expenditure

547. This chapter provides an overview of Western Power's forecast capital expenditure over the AA4 period, including the forecasting approach and key investment drivers.

8.1 Regulatory framework

548. Western Power's capex forecast is required to reflect the expenditure of a prudent service provider, acting efficiently, in accordance with good electricity practice, seeking to achieve the lowest sustainable costs of delivering the services, without reducing service standards below the service standard benchmarks set for each covered service in the access arrangement.[132]

549. Proposed capex must also satisfy various additional criteria such as maintaining safety, meeting network demand, satisfying compliance obligations, and ensuring the revenue generated from an investment exceeds the associated costs.

550. These criteria are described in the new facilities investment test (**NFIT**), prescribed in section 6.52 of the Access Code, which states:

> *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.*

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132 Section 1.3 – definition of 'efficiently minimising costs', *Electricity Networks Access Code 2004*.

551. Western Power assesses all forecast capex against the NFIT as part of its Investment Governance Framework. In all cases we consider which limb of the NFIT is satisfied before undertaking any investment. To ensure the investment program efficiently minimises costs, we also consider deliverability, economies of scale or scope, and forecast movements in market prices of labour and materials.

8.2 Overview of the investment proposal

552. During the AA4 period, Western Power proposes to invest $4,394 million of capital to deliver covered services. Of this, approximately $879 million will be recovered directly from customers in the form of either capital contributions or gifted assets. We forecast $3,514 million will be added to the regulated asset base and recovered through reference tariffs.

553. All expenditure values in this chapter are presented in real dollars at 30 June 2017, **and include real cost escalation and indirect costs.**

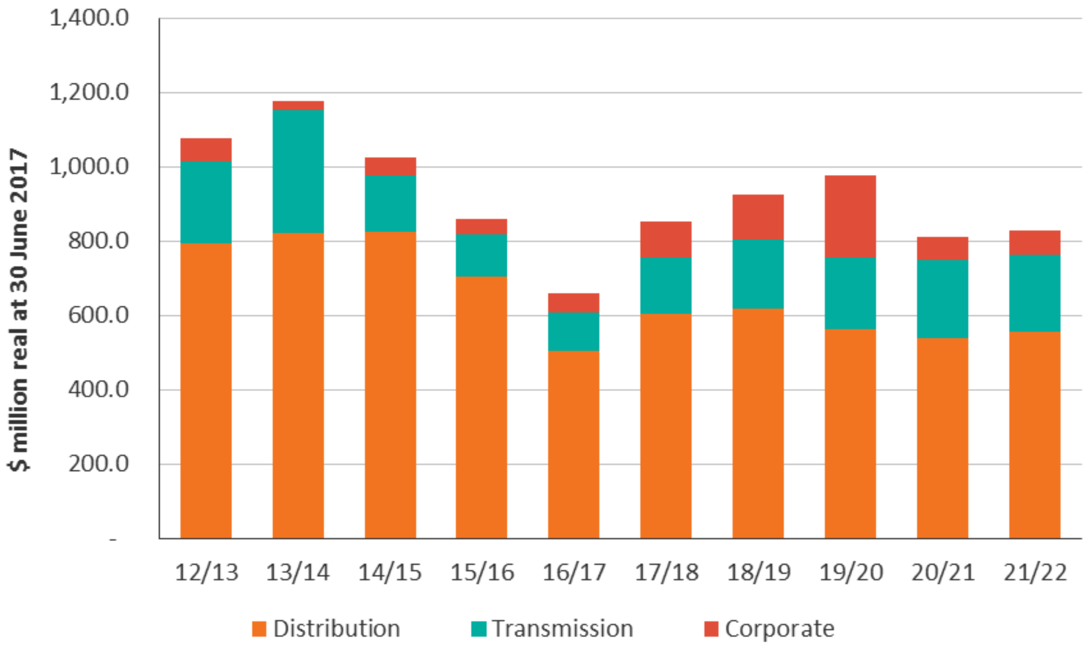
554. Table 8.1 summarises the total AA4 capex forecast split between investment in the transmission network, the distribution network, and corporate support.

Table 8.1: AA4 forecast capex summary including real cost escalation and indirect costs, $ million real at 30 June 2017

Expenditure category	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4	% of total WP gross capex
Transmission capex	149.4	188.2	192.4	211.2	206.1	947.3	22%
Distribution capex	604.3	617.2	563.1	538.0	554.8	2,877.3	65%
Corporate capex	99.5	120.2	221.1	61.2	66.8	568.9	13%
Gross capex	853.2	925.6	976.6	810.4	827.7	4,393.5	**100%**
Less contributions	178.3	194.9	173.7	163.1	169.3	879.3	
AA4 capex to be recovered via tariffs	**675.0**	**730.7**	**802.9**	**647.3**	**658.4**	**3,514.3**	

555. Figure 8.1 shows how AA4 forecast capex compares with that incurred during the AA3 period.

Figure 8.1: Comparison of AA4 forecast and AA3 actual gross capex

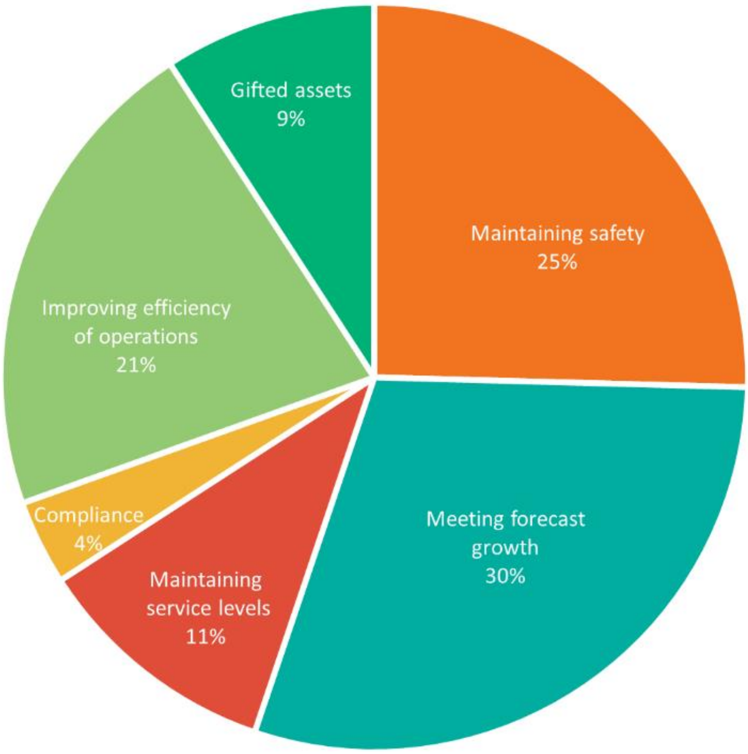


556. A breakdown of capex by regulatory expenditure category, **excluding real cost escalation and indirect costs** is provided the AA4 Forecast Capital Expenditure Report provided in Attachment 8.1.

557. Western Power's strategic objectives are to provide customers with a safe, reliable and efficient connection to electricity. The AA4 capex program is designed to help the business achieve these objectives, and has been informed by a comprehensive customer engagement process as described in Chapter 4. Our investment during the AA4 period is designed to:

- maintain the current levels of safety risk associated with the network
- maintain current levels of service standard performance for the distribution and transmission network (reliability of supply and security of supply), as well as call centre and streetlight performance
- meet forecast growth in the customer base and demand
- satisfy compliance requirements
- continue to improve the efficiency of operations.

Figure 8.2: AA4 forecast capex by outcome[133]



558. Focusing investment on achieving these five[134] outcomes, Western Power will undertake a prudent capex program that builds on the efficiency improvements and progress made over the past five years.

559. As always, safety remains a major part our investment focus. Safety expenditure during the period includes replacing more than 2,100 km of the highest risk overhead conductor, and replacing or reinforcing around 125,000 wooden power poles. Our bushfire management programs will also continue, focusing on mitigating safety risks in the areas that need it the most.

560. Expenditure in growth-related project remains a large portion of our forecast investment. Even though overall peak demand growth has slowed in recent years, parts of the network such as Mandurah and Bunbury are still growing much faster than elsewhere. That's why we are focusing much of our growth-related investment on these thriving areas, while augmenting the broader network to ensure the 1.1 million customers connected to it, and the ~96,000 new customers expected to connect over the next five years, have a reliable electricity supply.

561. The growth expenditure category also includes network augmentations in lieu of like-for-like asset replacements where it's more prudent to reconfigure the network and transfer load rather than replace a large number of assets.

562. We're also placing much greater focus on investments that will improve the efficiency of our operations. We propose to upgrade and implement new IT and communications systems that will help us operate and

133 Note 'gifted assets' shown in the chart is not an investment outcome, rather it represents the proportion of assets that are constructed by third parties and then transferred to Western Power to operate and maintain. Though gifted assets are not part of Western Power's capex program, they do account for a significant portion of the gross capex that features in Western Power's regulatory financial statements

134 'Gifted assets' is not an investment outcome. See above.

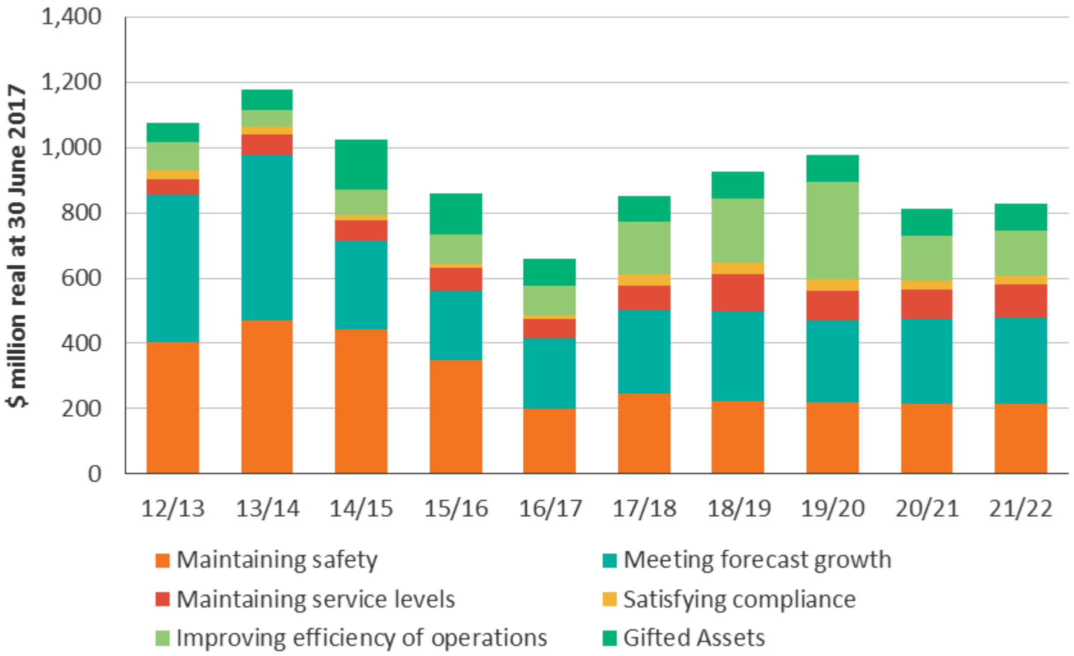
manage the network more efficiently. Most of our investment to improve operations is categorised as corporate capital expenditure, and includes improvements to our depots, our network security and control systems, and the countless other things that support the distribution and transmission networks.

563. New technology is likely to play a significant role in the future of Western Australia's electricity systems over the coming years, and we're looking at how we can adopt emerging technology for the benefit of our customers. At the moment the majority of our expenditure forecast relates to traditional poles and wires solutions. However, the emergence of battery storage systems, microgrids and more advanced distributed generation systems, means the solutions we actually put in place tomorrow could be quite different to the plans we have developed today. Our aim will be to adopt innovation network solutions where there is a clear cost saving or benefit to customers.

564. During the AA3 period we commenced several trials of emerging technology, ranging from battery storage trials in Perenjori to testing a standalone power system in Ravensthorpe. The information resulting from these trials is extremely valuable; helping to inform the type of non-network solutions Western Power could offer to customers. We plan to continue trialling non-network solutions and technology over the AA4 period, and where practicable, we will implement new technology in place of traditional solutions where it is safe and more efficient to do so.

565. Figure 8.3 shows how the AA4 forecast capex compares with AA3 capex, split by the five investment outcomes.

Figure 8.3: Comparison of AA3 actual and AA4 forecast capex by investment outcome, $ million real at 30 June 2017



566. Key capex programs relating to each of these outcomes are discussed in sections 8.2.2 to 668 below.

8.2.1 Capex forecast informed by customer insights

567. When developing the capex forecast we considered the price impact on customers and where possible, measured the expected reduction in risk (whether safety, reliability or non-compliance risk) achieved by replacing the asset or expanding the network.

568. In real terms, forecast capex is materially lower ($400 million) than that incurred in the AA3 period. This reduction alone means the impact of the AA4 capex program on customers' electricity bills is less than that of the AA3 period.

569. Perhaps more importantly, rather than assume lower levels of capex are what customers want, we have tested the proposed capex program against customer expectations and feedback drawn from our customer engagement program. [135]

570. Some of the key takeaways from this program were that our customers:

- are sensitive to price increases, and are not looking for costly improvements to Western Power's overall performance
- recognised the improvement in safety and reliability over the AA3 period, and indicated they are satisfied with Western Power's current network safety and reliability levels
- do not necessarily want Western Power to spend additional capital in order to improve overall service performance , however, would welcome continuous improvement to safety or reliability that can be achieved at no additional cost
- believe Western Power should target expenditure to address isolated or localised safety and reliability issues, and focus on ensuring overall network performance does not deteriorate
- recognise Western Power has an important role to play in WA's future electricity supply, and they see value in Western Power investing in emerging technologies to improve outcomes and operational efficiency.

571. A summary of customer insights is provided in Figure 8.4.

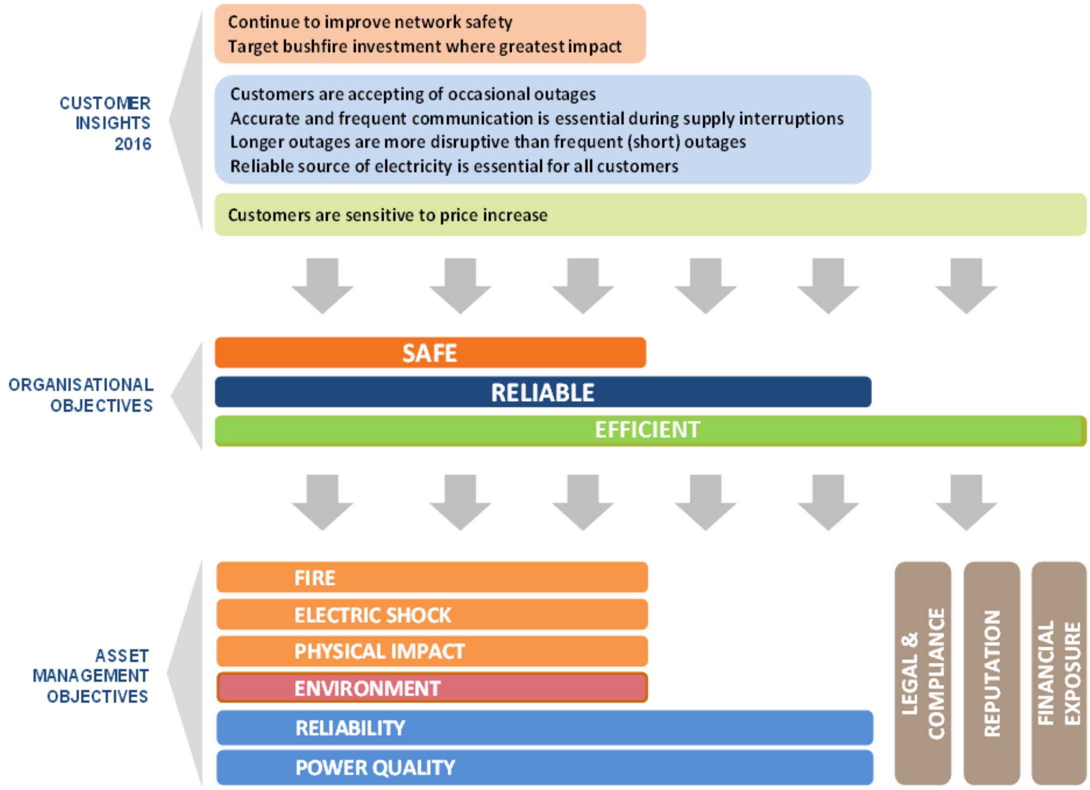
135 The customer engagement program is discussed in detail in Chapter 4 of this document.

Figure 8.4: Summary of customer insights

572. We listened to our customers and considered their feedback in light of our asset management objectives and the Access Code objective. We know our customers are sensitive to price increases and that price is the single most important factor when they make choices relating to electricity.

573. When developing our Network Management Plan (which is the plan that determines how we renew/replace network assets) we have considered customer insights as one of many factors that inform our asset management activities. When determining asset treatments (such as network upgrades or replacement), where possible, we have quantified the risk reduction per dollar and have considered the cost to customers of the forward works program.

Figure 8.5: Customer insights factored into the Network Management Plan



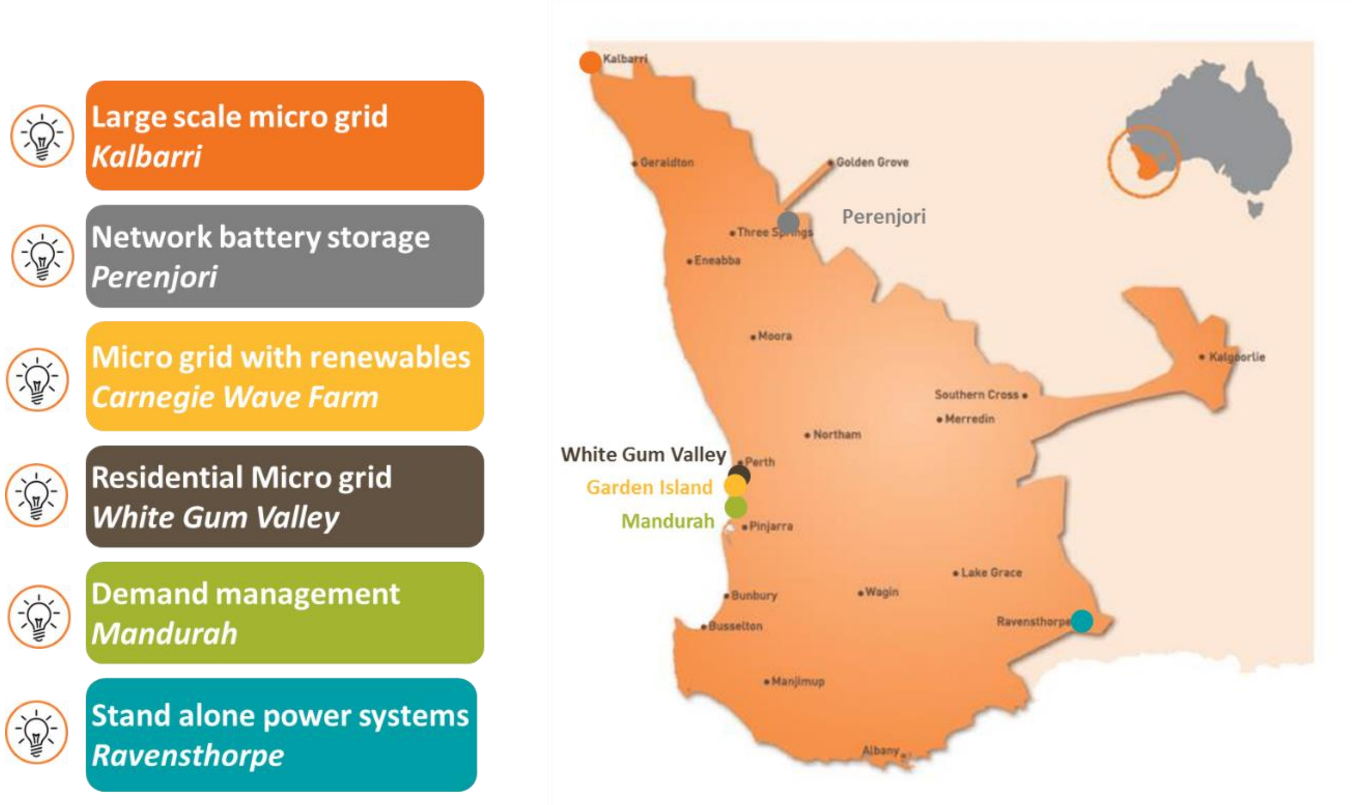
574. Consistent with customer expectations, our aim is to address the highest risks to network safety by attending to assets in the poorest condition. However, we note that customers are divided on whether they want to pay for safety improvement (insight #14). Therefore, rather than invest a higher level of capex to achieve blanket safety improvements across the network, we are taking a risk based approach whereby we maintain overall network safety levels as low as reasonably practicable (**ALARP**) and target expenditure on programs and areas of the network that will have the greatest impact.

575. A similar approach is being adopted for reliability performance. Again, customers highlighted that they value a reliable source of electricity and accept there will be occasional outages. Customers also indicated they do not necessarily want Western Power to spend additional money to improve overall network reliability. Therefore, our aim for the AA4 period is to maintain current network reliability levels, targeting expenditure on parts of the network that have poorer than average reliability, such as Kalbarri, Gnowangerup-Ravensthorpe and Perenjori-Morawa.

576. The majority of investment proposed in the AA4 period is traditional 'poles and wires' network capex, and reflects a prudent asset replacement program designed to maintain service levels, safety and compliance. However, customers have also told us that they *believe Western Power should use emerging technologies to deliver improved customer outcomes*. Therefore, as part of our investment governance process we will continue to pursue options for non-network solutions or introducing alternative technology.

577. For example, we will continue technology trials and implementing non-traditional solutions during the AA4 period – such as the microgrid trial in Kalbarri and the standalone power systems trial in Ravensthorpe – to mitigate reliability hotspots in country areas. Figure 8.6 provides an overview of non-network projects that have either been implemented during the AA3 period or are being investigated by Western Power as substitutes for traditional network solutions over the AA4 period.

Figure 8.6: Western Power's current non-network solution projects



578. It is important to note that there is an inherent trade-off between investment in emerging technology and traditional network solutions. Over the AA4 period we will continue to consider all feasible solutions for our required investment activities as part of our investment governance process. Table 8.2 summarises some of the key investment activities proposed for the AA4 period, and the customer insights that have informed them.

Table 8.2: Summary of AA4 investment activities and relevant customer insights

Investment activity	Informed by customer insight # (as per Figure 8.3)
Replace 2,196 km of overhead conductor and replace/reinforce around 125,000 wood poles – forecast expenditure on pole and conductor management is designed to maintain the current level of safety risk associated with these assets. More efficient asset management practices and lower replacement volumes means investment in these assets will be around 40 per cent lower than during the AA3 period, whilst maintaining network safety risk.	1 14
Use a risk based renewal approach to manage assets in poorest condition, located in the highest risk areas – consistent with customer feedback our safety and bushfire management investment will target parts of the Western Power Network where mitigation activities will have the greatest impact.	1 14 15

Investment activity	Informed by customer insight # (as per Figure 8.3)
Target investment on transmission assets to maintain overall reliability – we will invest to replace power transformers, circuit breakers, switchboards, static var compensators (**SVCs**), protection systems and primary plant. This investment is designed to address existing network security and power quality issues, and is necessary if current reliability levels are to be maintained.	1 10 11 12 13
Connect 96,000 new customers – though peak demand growth has flattened and average customer demand is declining, we still expect to connect around 96,000 new customers during the AA4 period.	1 13
Invest in improved SCADA and communications technology – this will improve Western Power's ability to control and monitor the network remotely. The ability to remotely monitor equipment and resolve issues enables us to make better use of our assets and extend asset life. By increasing remote monitoring of assets and data capture: - our staff can be deployed more efficiently as less time can be spent physically inspecting assets - we have greater visibility of asset condition, which can reduce the need for investment in capacity upgrade and/or asset replacement - faults and outages can be pinpointed more accurately, and in some cases resolved remotely – helping to reduce outage duration (something our customers have told us they value). Having a solid communications backbone is vital to any network business hoping to have a digital future. Access to real-time asset data via remote sensors and meters provides the information required to make network decisions, and in some cases can automate these decisions where safe to do so.	5 11 12
Invest in a new customer relationship management system – this will improve the quality and accuracy of information we can provide to our customers, helping to improve the customer experience.	2 3 4 11
Adopt advanced meters as the default replacement meter – we will install around 355,000 advanced meters over the AA4 period as part of our standard meter replacement program. This will provide customers greater visibility and control of their electricity usage, while helping improve Western Power's operating efficiency. Advanced meters will also facilitate the introduction of time of use tariffs and future tariff reforms, which will help put downward pressure on prices.	1 5 6 9
Continue to invest in emerging technology – we will continue technology trials of innovative solutions such as the Kalbarri microgrid during the AA4 period.	1 5 6

579. Using customer insights, we have designed a capex program that represents a prudent level of investment, designed to keep the business operating at today's level of performance, while making sure it delivers value to our customers and has efficient asset management practices in place.

580. The following sections provide a high-level overview of the key capex programs Western Power will undertake during the AA4 period. Our forecast is summarised by the capex outcomes shown in Figure 8.2.

581. A more detailed breakdown of forecast expenditure by regulatory expenditure category is provided in the AA4 Forecast Capital Expenditure Report provided in Attachment 8.1.

8.2.2 Maintaining safety

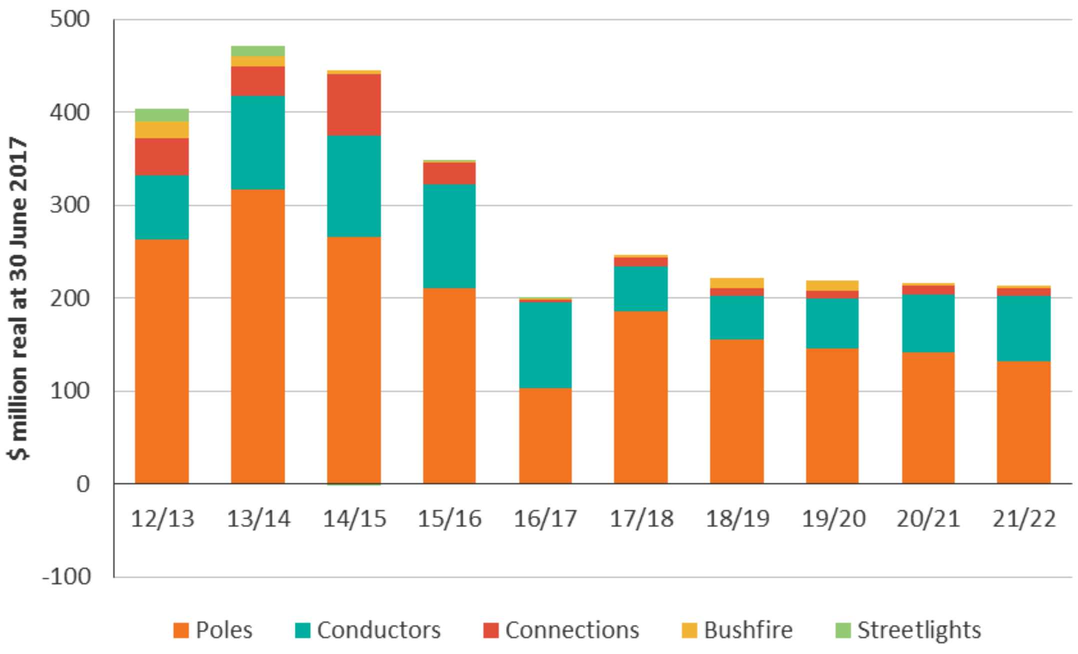
582. There is an inherent safety risk associated with all electricity networks. Electrical assets have the potential to cause harm to people or damage to property or the environment, through electric shock, fire, or physical impact. Western Power is responsible for managing this safety risk and a significant part of our investment in the network is to help keep our staff and the public safe from harm.

583. During the AA4 period, we will invest $1,117 million to maintain the current level of safety risk associated with the Western Power Network. This is 25 per cent of the total capital investment proposed for the AA4 period. Key works programs include:

- pole management
- conductor management
- connection management
- bushfire management

584. Figure 8.7 shows forecast and historical safety related investment.

Figure 8.7: Maintaining safety - comparison of AA3 actual and AA4 forecast safety-driven capex, $ million real at 30 June 2017



585. Transmission and distribution network assets have different impacts on safety, service and compliance outcomes. Given the distribution network tends to be in closer proximity to the public and property, distribution assets carry a greater likelihood of serious incident, and therefore carry a greater safety risk. As such, the majority (93 per cent) of safety-related expenditure is on the distribution network, with a focus on overhead assets such as conductor, poles, service connections and pole-top assets.

586. Our asset safety objective for the AA4 period (as outlined in the Network Management Plan, provided in Attachment 1.1) is to maintain the overall safety of the network (eliminating or reducing risk so far as is reasonably practicable) with actual safety performance not deteriorating below recent historical levels.

587. Safety performance is heavily influenced by external factors (such as adverse weather), therefore our aim is to manage the factors that are within our control, such as ensuring network assets are in good condition. We have adopted a risk based approach to asset replacement and renewal, targeting the poorest condition assets and identifying the treatments that achieve the greatest risk reduction per dollar invested.

588. We use a suite of IT solutions comprised of three core tools used to plan and package high volumes of distribution overhead asset replacement. The three tools are:

- **Network Risk Management Tool (NRMT)** – statistical modelling software used to calculate a risk score for each individual asset within each particular asset class. The NRMT quantifies the instantaneous risk of unassisted failure of individual assets and the future risk profile if left untreated
- **Asset Investment Planning (AIP) system** – a software application used to model distribution overhead asset strategies using the risk based renewal methodology to forecast future capex work. This is achieved by using asset strategy rules, asset condition, NRMT risk scores, unit rates and applying business priorities and constraints to generate detailed or summarised plans
- **Rules Engine** (**ARDS**) – is a software application that uses the output of AIP and coded business rules to automate distribution overhead maintenance decision-making. It supports management of maintenance estimates and automates work orders with allocated delivery arms.

589. The benefit of using these recently developed IT solutions is that it allows us to more accurately quantify risk and maintain oversight of the condition of our assets and associated investment activities. Better information leads to better investment decisions. This ultimately leads to efficient asset management.

590. The key safety-related works programs are summarised below.

8.2.2.1 Pole management

591. Western Power's distribution network consists mostly of wood poles (98 per cent). During the AA3 period Western Power made significant improvements in its wood pole asset management practices, replacing/reinforcing approximately 270,000 wood poles. The AA3 pole replacement program was driven by Energy*Safety* Order 2009-01, which required Western Power to address the safety risk associated with its rural wood pole population. Overall expenditure on pole management during the AA3 period was $1,158 million.

592. During the course of satisfying the Energy*Safety* order, we have gathered more information on the condition and risk associated with wood poles and have used this to develop an efficient, risk based pole management program for AA4.

593. At the end of June 2016, asset condition data indicated approximately 253,000 wood poles remain in the network that require treatment (either replacement or reinforcement). However, not all of these poles

require immediate treatment over the AA4 period. We have designed an AA4 works program that will treat around 125,000 wood poles, prioritising those that are in the poorest condition and/or pose the highest public safety risk.

594. For example, approximately 16 per cent (~40,000) of the 253,000 outstanding poles are located in extreme/high bushfire risk zones or in high risk public safety zones[136]. These highest risk poles are being treated now, and will continue to be prioritised for treatment during the AA4 period.

595. The progress we have made in our risk based renewal approach, combined with better asset data, means we can maintain the overall network safety risk associated with distribution wood poles despite the lower replacement/reinforcement volumes compared to the AA3 period. This is because the majority of poles with the greatest identified risk will have been treated.

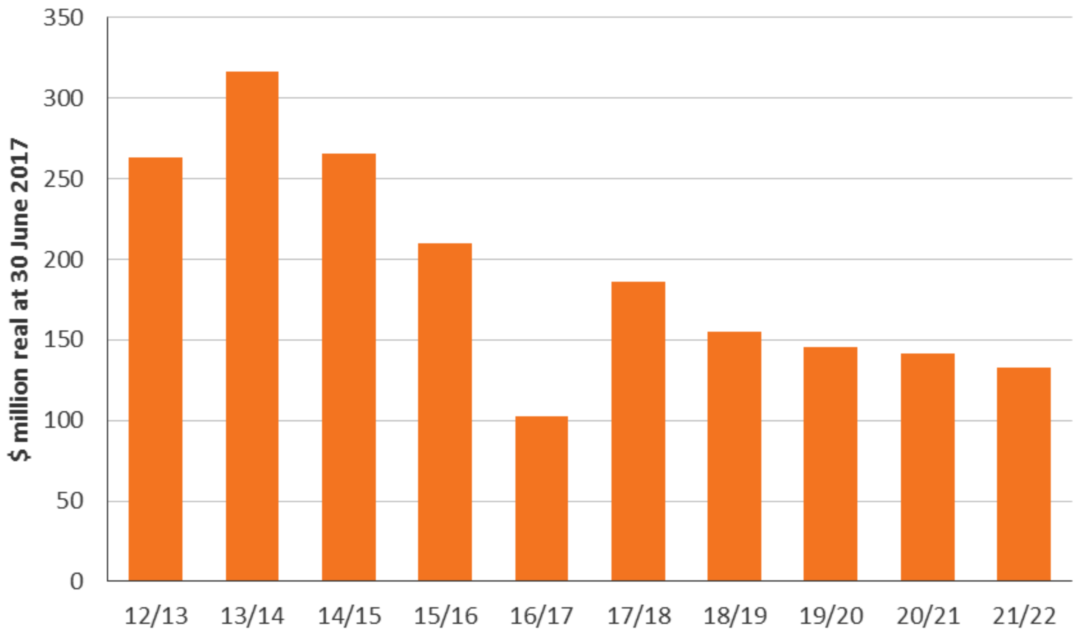
596. Further, the mixture of reinforcement and replacement forecast for the AA4 period is different to that of the AA3 period. During the AA4 period, around 61,000 (48 per cent) of the 125,000 poles identified for treatment will be replaced, and the remainder reinforced. During the AA3 period, approximately 82,000 (30 per cent) of the 270,000 treated poles were replaced. The high proportion of reinforcement during the AA3 period was primarily due to the high volume of poles that required treatment under the Energy*Safety* order.

597. Though replacement is more expensive than reinforcement, it is a longer-lasting solution and a more prudent form of treatment for the highest risk/poorest condition assets. Increasing the proportion of replacements compared to reinforcement will allow Western Power to maintain the current overall safety risk associated with wood poles while treating a smaller total volume of poles at a lower overall cost than during the AA3 period.

598. Forecast expenditure on distribution wood pole replacement / reinforcement in AA4 is $634 million. This is 39 per cent less than incurred during the AA3 period (see Figure 8.8).

136 For example near to schools, bus stops, or other densely populated areas where there is a greater risk that the public may come in to contact with assets if they fail.

Figure 8.8: Comparison of AA3 actual and AA4 forecast pole management capex, $ million mean at 30 June 2017



599. The $761 million total pole management investment forecast for the AA4 period also includes expenditure on transmission poles and towers, and replacement of cross arms, stay wires and insulators. The profile of pole replacement capex declines of the course of the period, with a view to achieving an even level of investment over the long term. The low level of expenditure during 2016/17 is due to the reprioritisation of works following completion of the program to meet the requirements of the Energy*Safety* order in 2015. 2016/17 also saw implementation of the Business Transformation Program, which saw the business scale back investment generally as it reviewed and improved its asset management and operational activities.

600. Further information on the AA4 pole replacement program is provided in the AA4 Forecast Capital Expenditure Report provided at Attachment 8.1, and in the Network Management Plan provided in Attachment 1.1.

8.2.2.2 Conductor management

601. Distribution overhead conductor refers to any bare or insulated wires that are predominantly used for carrying electrical current, suspended between two or more structures (with the exception of the final lines connecting properties to the distribution network). As at 30 June 2016, there was approximately 68,000 km of distribution overhead conductor in the Western Power Network. Of that, around 11 per cent were classified as 'urban', 15 per cent as 'rural short' and the majority, 74 per cent, as 'rural long'.

602. In a similar vein to our pole management, we also improved our conductor asset management practices during the AA3 period. Results from conductor testing and sampling in recent years has given us a better understanding of asset condition and the likelihood of asset failure. As a result, we are better able to identify conductor at the greatest risk of failure.

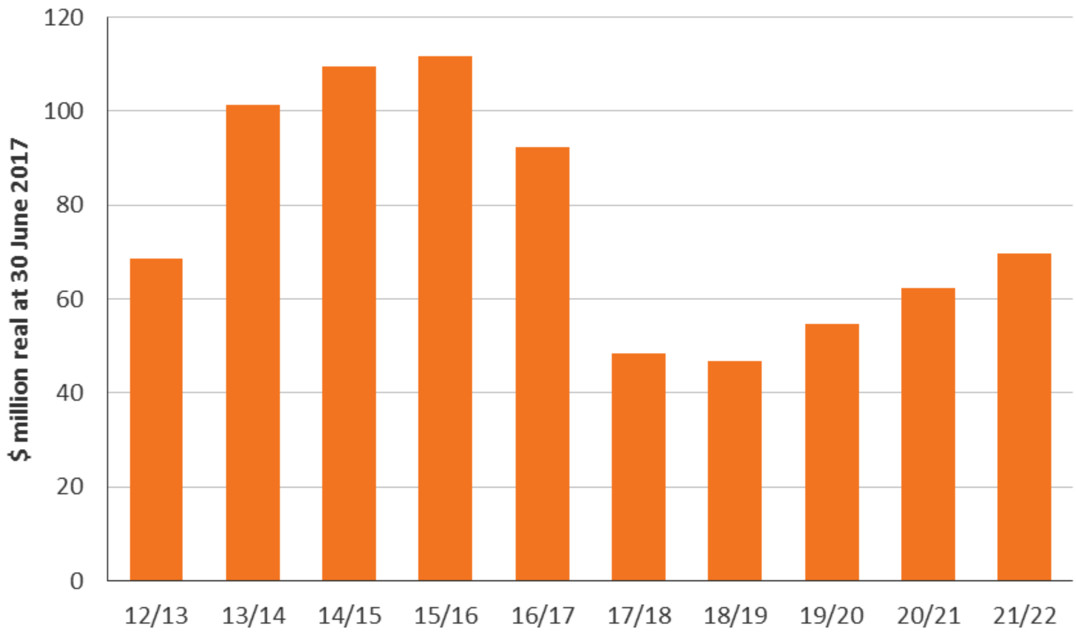
603. This means that for the AA4 period we are adopting a more mature risk based renewal approach to managing conductors. Our risk based renewal approach optimises asset lifecycle costs and helps determine a more efficient level of expenditure. The approach involves:

- identifying conductors that are in poor condition
- assessing the risk posed by these conductors
- scheduling treatments to achieve optimal risk reduction per dollar spent.

604. We have assessed that approximately seven per cent (4,760 km) of the 68,000 km of distribution overhead conductor is in poor condition. Not all of this poorest condition conductor requires immediate treatment, and we do not propose that all 4,760 km will be replaced during the AA4 period. Instead, we will replace 2,196 km of overhead conductor, prioritised by risk. We will monitor the condition of the remaining distribution conductor during routine maintenance, and adjust the reactive and proactive replacement programs as necessary to keep the safety risk as low as reasonably practicable.

605. Forecast expenditure on conductor management during the AA4 period is $282 million. This is 42 per cent less than incurred during the AA3 period (see Figure 8.9).

Figure 8.9: Comparison of AA3 actual and AA4 forecast conductor management capex, $ million real at 30 June 2017



606. Western Power's transmission overhead conductor is in relatively good condition. The number of unassisted failures is currently averaging one per annum and as at 30 June 2016 there were no overhead transmission conductors beyond their mean replacement life. Transmission conductor failure poses a lower risk to public safety than distribution overhead conductor.

607. The current impact of assisted and unassisted failures of the overhead conductors is within transmission network reliability targets.[137] However, we will monitor ongoing asset condition and will review the transmission overhead conductor replacement requirements as part of our annual investment planning process.

137 Refer to Western Power's Network Management Plan.

8.2.2.3 *Connection management*

608. Overhead customer service connections are the highest contributor to electric shock incidents associated with the Western Power Network. During the AA3 period, Western Power removed the known highest risk service connections ('twisties') from the network. As a result, the asset replacement forecast for the AA4 period is considerably lower than AA3. However, the remaining service connections require ongoing monitoring and asset replacement in order to manage the public safety risk as the assets age and deteriorate.

609. For the AA4 period, we propose a program of condition-based asset renewal, using data extracted from advanced metering infrastructure (specifically the SCADA and communications backbone) to be installed during the AA4 period. Using the condition-based approach, forecast expenditure on connection management is $43 million, 74 per cent less than that incurred during the AA3 period.

610. Note that the condition-based renewal forecast is dependent on the installation of the advanced metering infrastructure.

8.2.2.4 *Bushfire management*

611. Activities such as replacement of poles, reinforcement of poles and conductor replacement are significant contributors to bushfire management. The primary bushfire management activity for the AA4 period is the 'high voltage conductor clashing program'. The aim of the program is to mitigate the risk of overhead conductors coming into contact with each other and causing sparks, which could lead to ground fires. The various solutions to conductor clashing include installing longer cross arms, installing taller poles, re-tensioning the line or a complete redesign of the bay.

612. Bushfire management also includes undertaking LiDAR[138] surveys of lines where conductor clashing has occurred. This survey technique helps scope the remediation work required on network segments, and identify the most prudent and efficient form of treatment.

613. Bushfire management expenditure during the AA4 period is $31 million, which is 21 per cent less than incurred during the AA3 period. Even though the bushfire investment is lower than during the AA3 period, this does not mean we are doing less to prevent bushfires.

614. The lower expenditure level is due to a change in asset treatment compared to the AA3 period, which will see a higher number of reclosers installed on the network. A recloser is a type of circuit breaker installed on the network that can automatically close the breakers after it has been opened due to a fault (such as clashing). During the AA3 period we found that installing reclosers is a more effective and efficient method of mitigating the bushfire risk associated with conductor clashing than re-designing long bays.

8.2.3 Maintaining service levels

615. Feedback during our recent customer engagement program indicates that customers are generally satisfied with overall current levels of performance. As a result, Western Power's reliability driven expenditure during AA4 is designed to maintain service at the levels achieved at the end of the AA3 period. While we will target parts of the network that are performing below service standards, we do not expect network-wide performance to improve.

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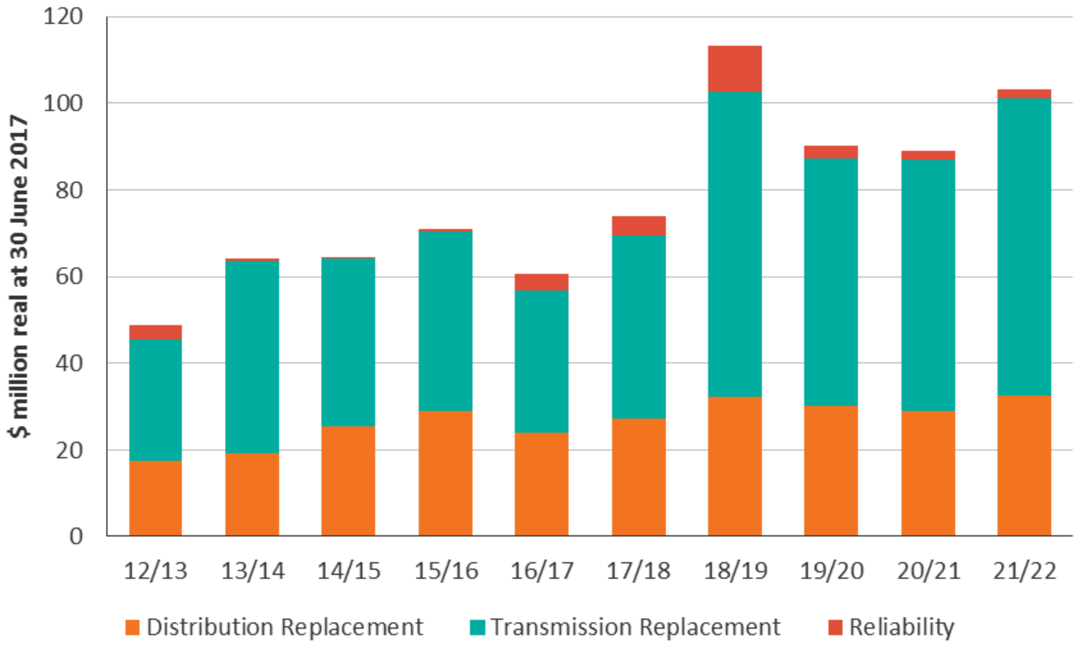
138 Light detection and ranging.

616. However, because service performance has already improved over the past five years, the service standard targets and benchmarks in the regulatory incentive scheme[139] for the AA4 period are set at more challenging levels than those set at the beginning of the AA3 period. As a result, reliability driven capex will be greater during the AA4 period than in the AA3 period in order to maintain the service performance targets.

617. During the AA4 period, Western Power will invest $470 million to maintain service levels. This is 11 per cent of the total capital investment proposed for the AA4 period. Figure 8.10 shows forecast and historical investment in service.

Figure 8.10: Maintaining service levels – comparison of AA3 actual and AA4 forecast service performance capex, $ million real at 30 June 2017



618. The increase in service-related capex during the AA4 period is primarily driven by a required increase in transmission asset replacement. During the AA3 period, a significant number of transmission asset replacement projects had to be deferred due to major transformer failures at Muja.

619. The Muja Bus Tie Transformer #1 (**BTT1**) had failed in 2012. In February 2014 the Bus Tie Transformer #2 (**BTT2**) at Muja also failed, causing significant disruption to customers, and also to the forward works program. This second failure in less than two years highlighted the issues facing the network.

620. The BTT2 failure and resulting network security issues meant much of the southern part of the Western Power Network was not switchable[140], therefore planned asset replacement could no longer go ahead. The BTT1 and BTT2 issues have now been addressed, and transmission asset replacement (albeit a revised and optimised program) can recommence.

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139 SSAM and SSBs – see Chapter 6.

140 The ability to re-route electricity to alternative circuits so planned work can commence on specific parts of the network.

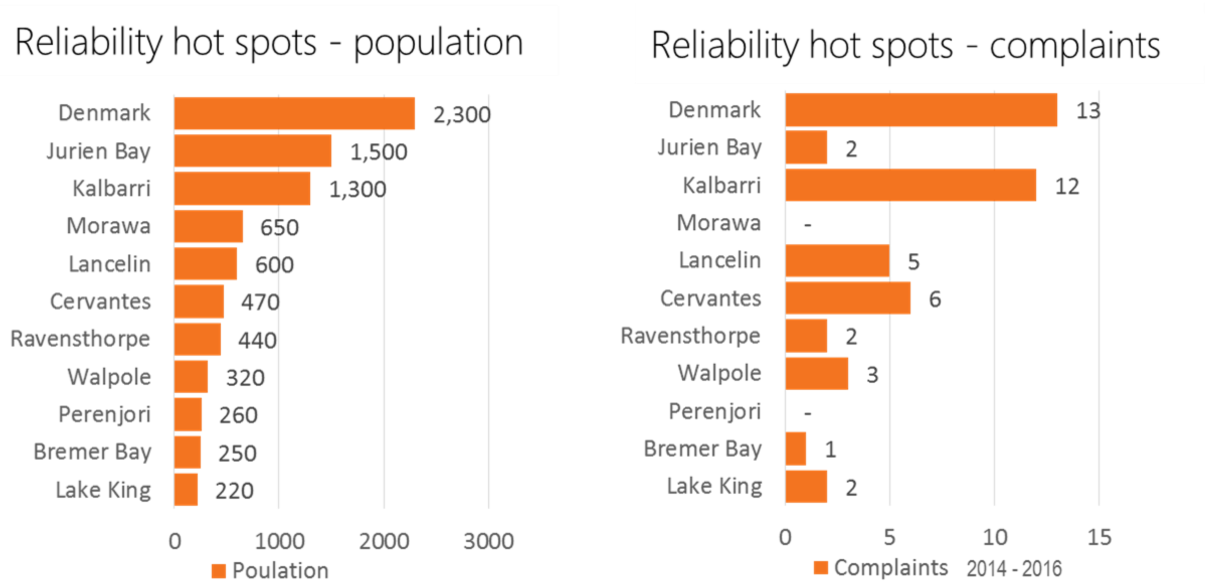
621. We will invest $296 million to replace transmission assets such as power transformers, circuit breakers, switchboards, SVCs, protection systems, and primary plant. This investment is designed to address existing network security and power quality issues, and is necessary if current reliability levels are to be maintained.

622. Other specific reliability projects include the reliability hot spot program.

8.2.3.1 Targeted reliability hot spots- Kalbarri

623. Though overall network reliability is good, there are parts of the network that experience poorer reliability than elsewhere in the SWIS. These reliability hot spots are typically in regional WA and at the extremities of the Western Power Network. Figure 8.11 shows identified reliability hot spots, sorted by population size and number of customer complaints.

Figure 8.11: Western Power Network reliability hot spots



624. Our customer engagement program identified that while customers do not necessarily wish Western Power to increase overall network reliability, they recognise that there are poor performing parts of the network. They have told us *a reliable source of electricity is essential for all customers, and customers are willing to spend money to ensure all people on the network have a reliable source of electricity*.[141] The customer engagement program also highlighted that *customers believe Western Power should use emerging technology to deliver improved customer outcomes*.[142]

625. With this in mind, our plan is to continue the reliability hot spots program during the AA4 period and improve reliability for customers who are connected to the less reliable parts of the network.

626. The town of Kalbarri has been identified as a reliability hot spot. It is supplied solely through a 140 km, 33 kV feeder from Geraldton. The feeder is one of the worst performing on the Western Power Network, and customers suffer a high frequency of outages. While all of the hot spots identified in Figure 8.11 will be targeted during the AA4 period, Kalbarri has been targeted as an area of the network where it may be more efficient to trial and implement non-traditional network solutions.

141 Customer insight #13, *Western Power customer insights feedback report*, Deloitte, August 2016.

142 Customer insight #5, *Western Power customer insights feedback report*, Deloitte, August 2016.

627. A range of potential solutions to the Kalbarri reliability problems have been considered and tested with people in the Kalbarri community. An October 2016 feasibility study recommended the development of a microgrid.

628. The microgrid concept has been shared with Kalbarri stakeholders, and investigation into the costs and technical solution has begun. Western Power proposes the Kalbarri microgrid will be powered by a combination of energy storage systems and the existing Kalbarri windfarm, and will include innovative system protection measures. The anticipated benefits are:

- fewer and shorter duration outages for customer in Kalbarri
- improved rural distribution asset utilisation
- valuable data on the interaction of microgrids with the main network and feasibility of similar solutions for other regional networks.

629. The estimated cost of the Kalbarri microgrid is $9.5 million, and the project is expected to commence in 2018.

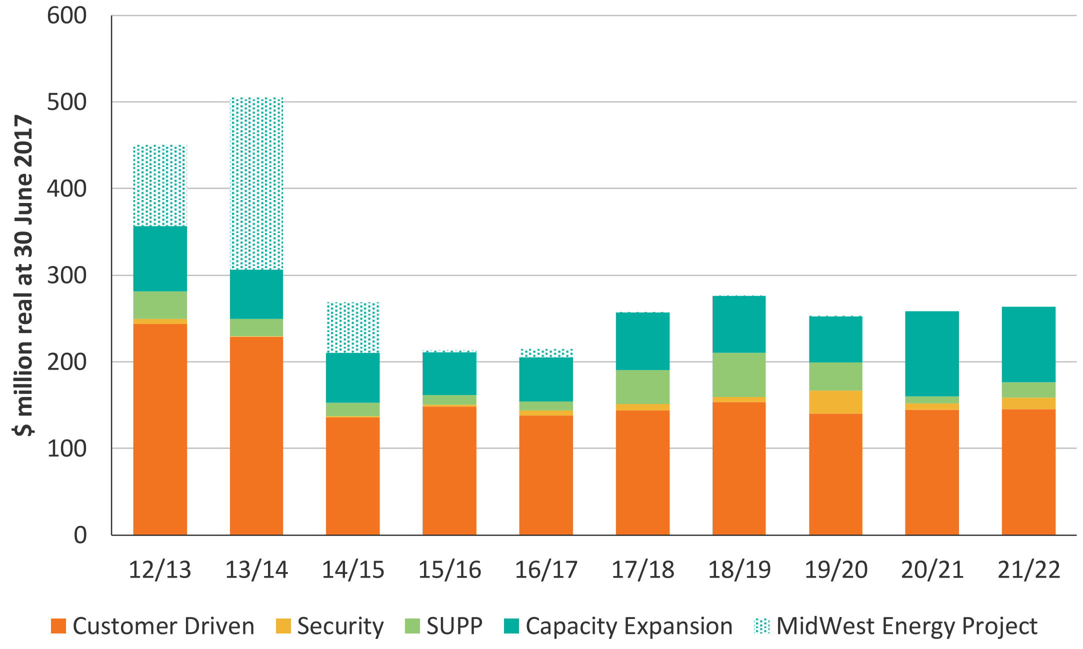
8.2.4 Meeting forecast growth

630. Growth capex (both transmission and distribution) is typically one of the largest areas of investment for an energy network business. However, this category of expenditure is dependent on a range of external factors including peak demand, economic conditions, emerging technology and customer actions. As a result, actual growth capex can vary significantly from the forecast if there are major shifts in any or all of these external factors (as was the case during the AA3 period).

631. We therefore propose transmission and distribution growth capex remains subject to the investment adjustment mechanism during the AA4 period, as it was during AA3. This allows revenue to be adjusted in the AA5 period for variances from forecast, and ensures customers are no worse off as a result of changes in growth investment.

632. Western Power will invest $1,308 million in growth projects during the AA4 period. This is 30 per cent of the total capital investment proposed for the AA4 period, and $345 million (21 per cent) less than that incurred during the AA3 period. Figure 8.12 shows forecast and historical investment in growth.

Figure 8.12: Meeting forecast growth – comparison of AA3 actual and AA4 forecast growth-related capex, $ million real at 30 June 2017



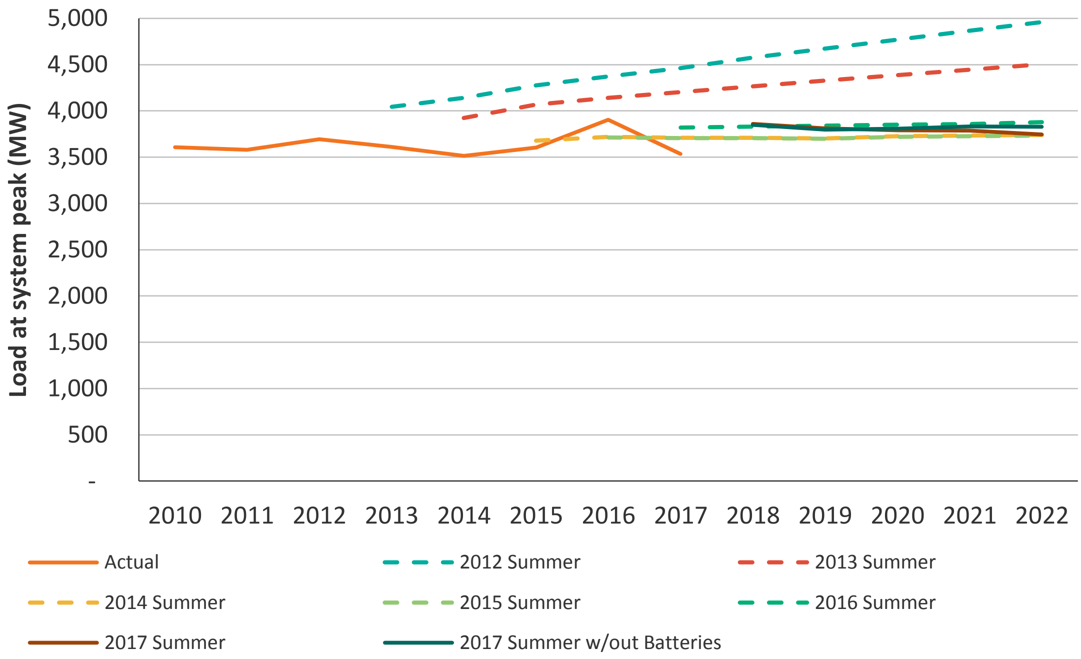
633. Despite the overall decline in growth investment, and the slowdown in network growth and peak demand forecast over the coming years (discussed below), growth-related expenditure remains a large proportion of total expenditure. This is because while growth across the network as a whole has slowed, there are parts of the network where growth is above average (Mandurah, Bunbury and Busselton for example) and localised investment in capacity is required. Growth capex also includes projects driven by individual customers, which tend to be driven by economic conditions and traditionally represent a significant portion of the works program.

Growth capex is split into two sub-categories:

- capacity expansion
- customer driven projects.

634. The main drivers of capacity expansion are forecast peak demand and customer numbers growth forecasts. Over the AA3 period, forecast growth has not materialised and peak demand growth rates have been substantially revised downwards each year since 2012 (see Figure 8.13).

Figure 8.13: Peak demand growth projections 2012 to 2017



635. The flattening of peak demand growth in recent years is due to decreasing economic activity in Western Australia (particularly in the resources sector), the influx of rooftop solar generation systems, improved efficiency of electrical appliances, and changes in consumer behaviour. These falling projections mean less transmission capacity expansion investment is expected to be required to meet peak demand than in previous periods.

636. Despite flat forecast peak demand, we have identified growth in some areas, which will drive the transmission network investment over the next 10 years. The Mandurah, Bunbury and Busselton areas in particular, are expected to experience steady growth in peak demand.

637. We have also identified several areas of the network where a shortage in voltage support is expected within the next 10 years. Insufficient voltage support can lead to network damage or damage to customers' equipment. It can also lead to widespread outages and non-compliance with Technical Rules requirements.

638. We will invest $431 million during the AA4 period on distribution and transmission capacity expansion projects. This is $238 million (36 per cent) less than that incurred during the AA3 period.

639. Western Power's Network Development Plan (provided at Attachment 1.2) outlines the current network risk and the projects the business will undertake over the next 10 years to address network capacity issues.

640. Customer driven capex includes all work associated with connecting customer loads or generators, and relocation of assets. Projects range from small residential connections (pole to pillar), through to network extensions to cater for large industrial customers.

641. We will invest $728 million (including capital contributions) during the AA4 period on customer driven transmission and distribution projects. This is $167 million (19 per cent) less than that incurred during the AA3 period.

8.2.4.1 *The State Underground Power Program*

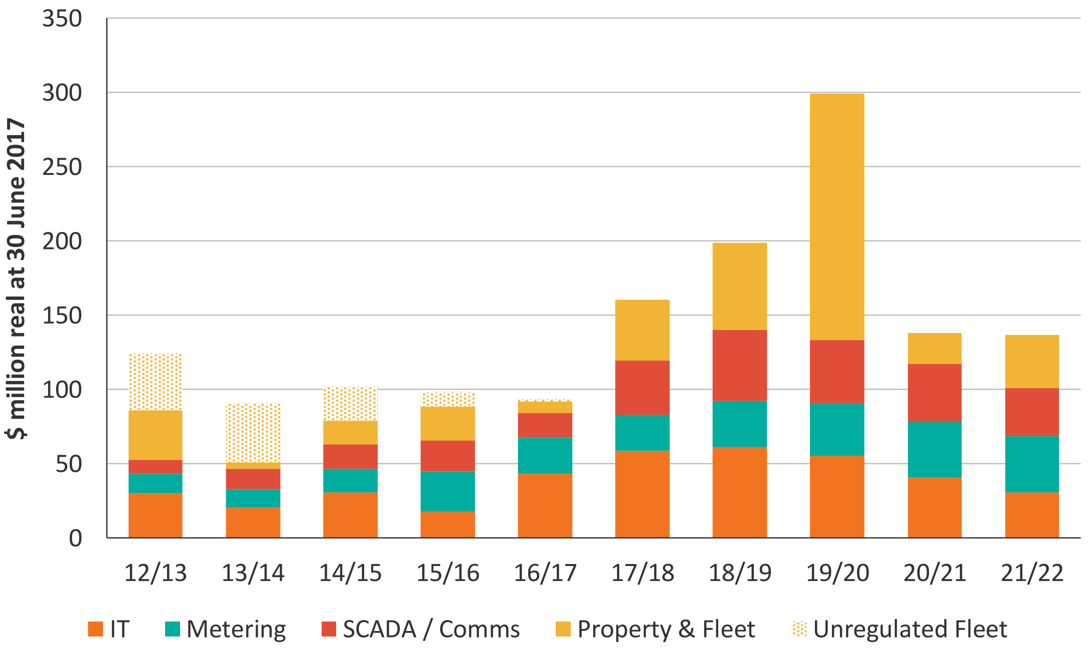
642. SUPP is an initiative where Western Power replaces overhead power lines with underground power infrastructure. The SUPP is a partnership between the State Government, Western Power and local governments.

643. Since it was initiated (in 1996), SUPP has converted around 87,000 households to underground power.[143] In January 2017 the State Government announced the sixth round of funding for SUPP. Of the 62 applications received, 17 projects were chosen. Works started in the first half of 2017 and are expected to be completed by the end of 2021. Western Power has forecast to invest $149 million in SUPP during the AA4 period. This compares to $89 million invested during the AA3 period. The increase is because more councils have approached Western Power requesting retrospective undergrounding, therefore Western Power is undertaking more projects than in the AA3 period.

8.2.5 Improving the efficiency of our operations

644. During the AA4 period, Western Power will invest around $933 million on projects designed to enable the business to operate more efficiently. This is 21 per cent of the total capital investment proposed for the AA4 period. Figure 8.14 shows historical and forecast investment in programs related to improving operational efficiency.

Figure 8.14: Improving operational efficiency – comparison of AA3 actual and AA4 forecast operational efficiency-related capex, $ million real at 30 June 2017[144]



645. Expenditure to enable us to undertake network operations more efficiently includes ICT investment, rationalisation and modernisation of depots, an upgrade of SCADA and communications systems, and investment in advanced metering.

[143] Western Power, as at November 2016 - available at: https://westernpower.com.au/community/projects/

[144] The AA3 values used in this chart include $112 million of unregulated Fleet capex for comparative purposes

8.2.5.1 Advanced metering infrastructure

646. Western Power currently installs basic meters at small use customers' premises (residential and small business). These meters are manually read every two months with only basic consumption and net generation data being retrieved.

647. The capital cost of the meters is included in Western Power's RAB and the ongoing operational expenses such as manual meter reading are considered to be part of the cost of operating the network. As such, all customers pay for metering as part of their tariff. The cost of advanced meters have fallen significantly in recent years and are now closer to the costs associated with installing and operating basic meters.

648. Advanced meters are now routinely deployed by utilities around the world, and research indicates that the benefits across the electricity value chain outweigh the costs of deployment over the meter's life. Feedback from our customer engagement program indicated that customers support adaptation of new technology, and would support adoption of advanced meters where it's efficient to do so.

649. Western Power proposes to change the default replacement meter from basic meters to advanced meters. The Advanced Metering Infrastructure (**AMI**) Business Case (provided in Attachment 8.2) outlines the incremental deployment of advanced meters and associated communications infrastructure over the next 15 years, including 355,000 new and replacement meters during the AA4 period.

650. Investment in AMI is forecast at $209 million[145]. This will allow a move from the current basic meter standard to the advanced meter standard. Metering capex also includes the associated communications infrastructure and IT system costs to allow Western Power to access interval data and meter alarms remotely.

651. There is the potential that demand for advanced meters may be different to Western Power's forecast, particularly if future market reforms require a retailer-led implementation of advanced metering services. Therefore we propose distribution metering investment be subject to the IAM.

8.2.5.2 SCADA and communications

652. Western Power's SCADA and communications assets provide the information and technology services required to protect, operate and manage the transmission and distribution networks and the Wholesale Electricity Market. The SCADA and communications system is comprised of:

- the SCADA master station – located at the control centre from where Western Power centrally operates and manages the transmission and distribution networks
- substation SCADA and distribution automation – field monitoring and control of electronic equipment to operate plant and equipment at every substation (as well as across overhead and underground distribution networks)
- the telecommunications network – providing the voice and data infrastructure required to transfer information between the electricity network, substations, depots and the control centre.

653. Over previous regulatory periods, Western Power's SCADA and communications network has been maintained on a reactive basis, and has now reached the point where technical obsolescence becomes an issue.

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145 Elements of advance metering infrastructure investment feature in the IT, Metering, and SCADA & communications expenditure categories.

654. Western Power will invest $199 million (combined transmission and distribution capex) in SCADA and communications systems during the AA4 period. This compares to $76 million incurred during the AA3 period. The increase in investment is required to replace obsolete SCADA and communications equipment and maintain the performance of system monitoring and control.

655. A key aspect of SCADA and communications investment is in 'last mile telecommunications', which allows automation and remote control, and data capture from across the distribution network. Improved last mile communications are critical for the implementation of advanced metering and the efficient connection and management of emerging technologies such as microgrids and battery storage systems.

656. Investing in SCADA and communications will improve Western Power's ability to control and monitor the network remotely. The ability to remotely monitor equipment and resolve issues enables us to increase asset utilisation and extend asset life. By increasing remote monitoring and data capture, staff can be deployed more efficiently as less time can be spent physically inspecting assets. Increased asset utilisation can also reduce the need for investment in capacity upgrade and/or asset replacement.

657. Enhanced SCADA and communications also means faults and outages can be pinpointed more accurately, and in some cases resolved remotely. This helps reduce outage duration, which is something customers have told us they value. Having a solid communications backbone is vital to any network business hoping to have a digital future. Access to real-time asset data via remote sensors and meters provides the information required to make network decisions, and automate these decisions where safe to do so.

658. A breakdown of transmission and distribution SCADA and communications costs is provided in the AA4 Forecast Capital Expenditure Report provided in Attachment 8.1.

8.2.5.3 ICT investment

659. Forecast capex on ICT during the AA4 period is $246 million. This is $104 million (73 per cent) more than that incurred during the AA3 period.

660. Most of the relative increase in ICT capex relates to upgrades and replacements of existing ICT systems that are out of date or nearing end of life. These changes are designed to improve business processes and help to realise the efficiencies that were identified in the recent Business Transformation Program. As discussed in Chapters 3 and 5, Western Power's Business Transformation Program commenced in 2015, with many initiatives having a direct or indirect ICT component.

661. Expenditure directly related to the business transformation initiatives is ongoing, and we expect to complete the related projects during 2017/18. However, a key outcome of the Business Transformation Program is the business' greater dependence on automation and ICT systems, particularly in the asset management space. Therefore, to ensure the benefits of the business transformation are maintained over the long term, investment in enhancing and maintaining these systems is required.

662. For example, Western Power's enterprise resource planning system Ellipse, and geographical information system SPIDA, require upgrades during the AA4 period. Ellipse has not been upgraded since 2010, while SPIDA requires enhancement to provide more accurate and timely analysis of the network, which will support the asset management improvements made during the Business Transformation Program.

663. We also propose to invest in a new customer relationship management (**CRM**) system to replace the existing ten-year old system. During our customer engagement program, customers told us they believed that accurate and timely support is essential for a positive customer experience. The new CRM system[146]

146 CRM systems are now able to manage various customer requirements like social media to enhance the customer experience.

will integrate customer quotations, fault reporting, meter reading, vegetation management and work orders – providing a single view of customer requirements and improving data accuracy and retrieval.

8.2.5.4 Property and fleet

664. One of the most significant operational efficiency projects proposed for the AA4 period is the modernisation of Western Power's metropolitan and regional operational depots.

665. Western Power currently owns and operates 14 depots in the Perth metropolitan area and south-west region of Western Australia, with a further 16 depots in regional locations. Many of these depots are dilapidated and require substantial upgrade and repair works.

666. During the AA4 period we propose to deliver phase one of the depot modernisation program, which will focus on the Perth metropolitan and south-west depots. The depots will be re-designed and re-fitted to reduce health and safety risks and operating costs, as well as providing sufficient accommodation to meet current and future operational requirements. Phase two of the program will commence at the end of the AA4 period and be completed during the AA5 period. Phase two will focus on improving the facilities at the regional depots.

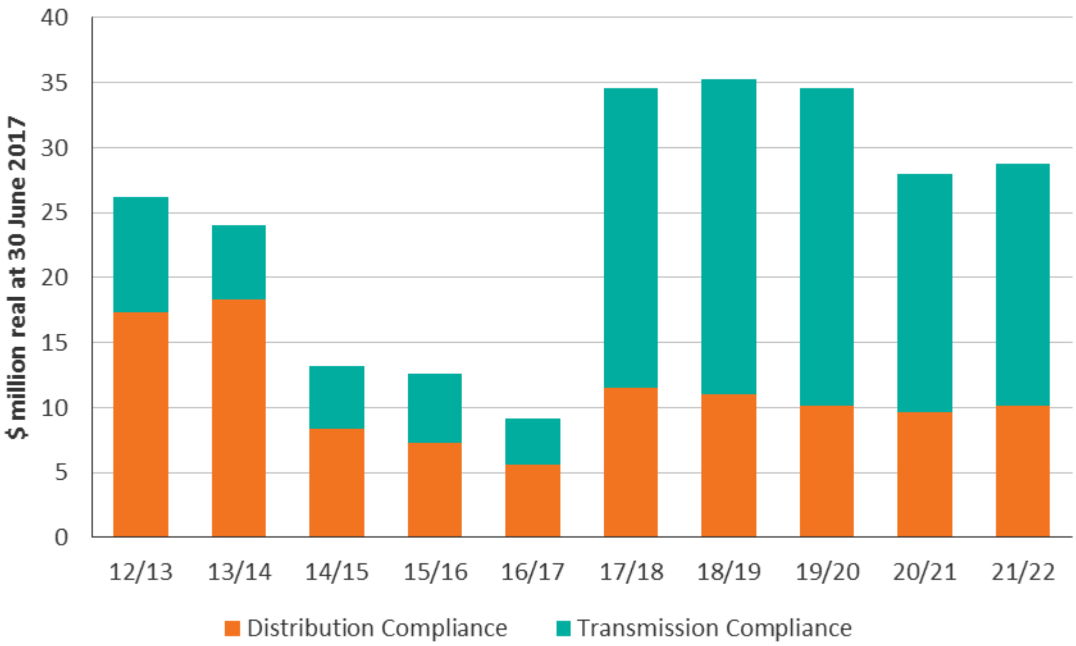
667. We expect phase one of the program to deliver recurring expenditure savings of $10 million per annum, and one-off benefits of $60 million. The depot modernisation program has already seen the closure of Western Power's Fremantle Depot, Perth Airport Fleet Services and the Bentley Depot. These closures have generated $4.5 million in recurring opex savings.

668. Other corporate real estate projects proposed for the AA4 period include relocation of Western Power's network control centre. The primary driver for the relocation is that the building is beyond its useful life, with wiring and roofing requiring substantial modernisation.

8.2.6 Satisfying compliance requirements

669. Western Power has a range of compliance requirements relating to environmental, power quality, and network security obligations (safety compliance obligations are captured in the 'maintaining safety' capex category). During the AA4 period, Western Power will invest $161 million on satisfying these requirements. This is four per cent of the total capital investment proposed for the AA4 period. Figure 8.15 shows forecast and historical compliance investment.

Figure 8.15: Satisfying compliance – comparison of AA3 actual and AA4 forecast compliance capex, $ million real at 30 June 2017



670. The largest regulatory compliance program forecast for the AA4 period relates to transmission substation security ($87 million). This accounts for more than half the forecast regulatory compliance spend. National guidelines[147] were introduced in 2015 relating to protection of critical infrastructure, including electricity substations. Therefore Western Power has developed an expenditure program to ensure compliance with the guidelines.

671. Another major transmission compliance program is transformer compliance. Transformer non-compliance can be categorised into three areas:

- transformers with no bunding or with bunding that is no longer able to contain oil spills in accordance with Australian Standards and Western Power standards
- transformers with noise emission levels that do not comply with the limits prescribed under the *Environmental Protection (Noise) Regulations 1997*
- transformers with no firewalls or with firewalls that provide inadequate protection and containment of fires in accordance with Australian Standard 2067 and Western Power standards.

672. At 30 June 2016 there were 25 sites that were non-compliant in terms of the issues above. Western power proposes 15 of the highest risk sites be addressed by the end of the AA4 period, at a cost of $15 million.

673. In the distribution network, the largest non-safety driven compliance program is addressing customers' power quality complaints ($25 million). Details of forecast compliance expenditure is provided in the AA4 Forecast Capital Expenditure Report provided in Attachment 8.1 and in the Network Management Plan in Attachment 1.1.

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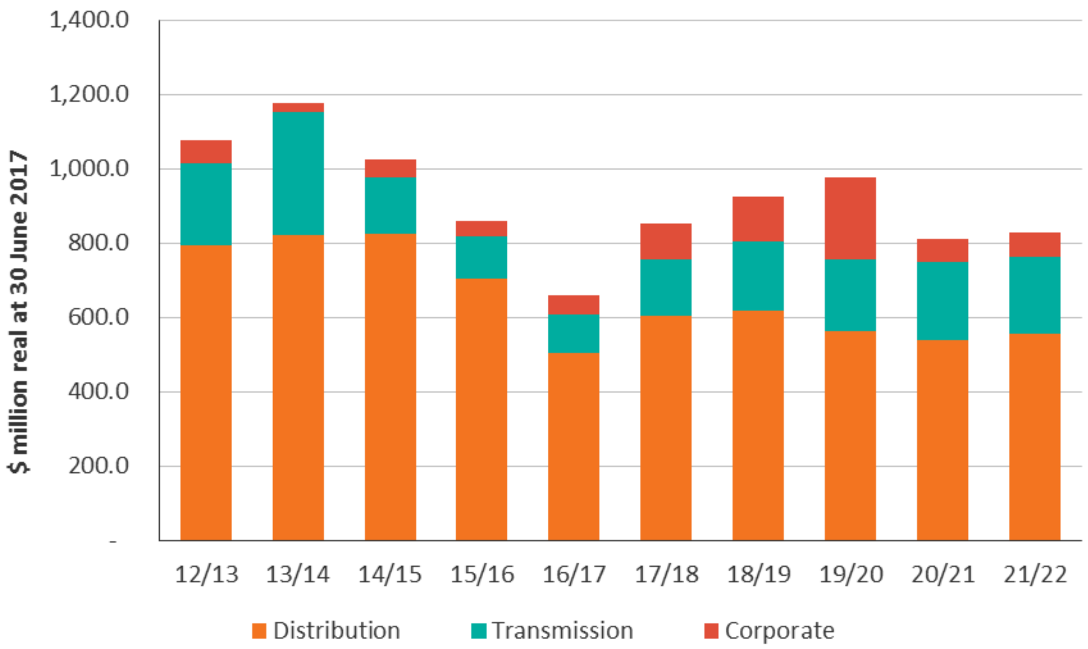
[147] *National Guidelines for Protecting Critical Infrastructure from Terrorism*, Australia-New Zealand Counter-Terrorism Committee, 2015.

8.3 Comparison of AA4 and AA3 capex programs

674. In real terms, forecast capex is materially lower ($400 million) than that incurred in the AA3 period. The profile of our investment program is also significantly different to that of the AA3 period, and reflects the efficiencies we have achieved via the Business Transformation Program and ongoing improvement in business-as-usual practices over the past five years. For example, improvement in asset management processes and productivity means we can maintain current service performance despite spending less on asset replacement and network growth than we did throughout the AA3 period. The AA4 period also sees greater investment in ICT systems and operating facilities, which will support more efficient delivery of the capital works program.

675. Figure 8.16 shows how the AA4 capex forecast compares with actual capex incurred during the AA3 period.

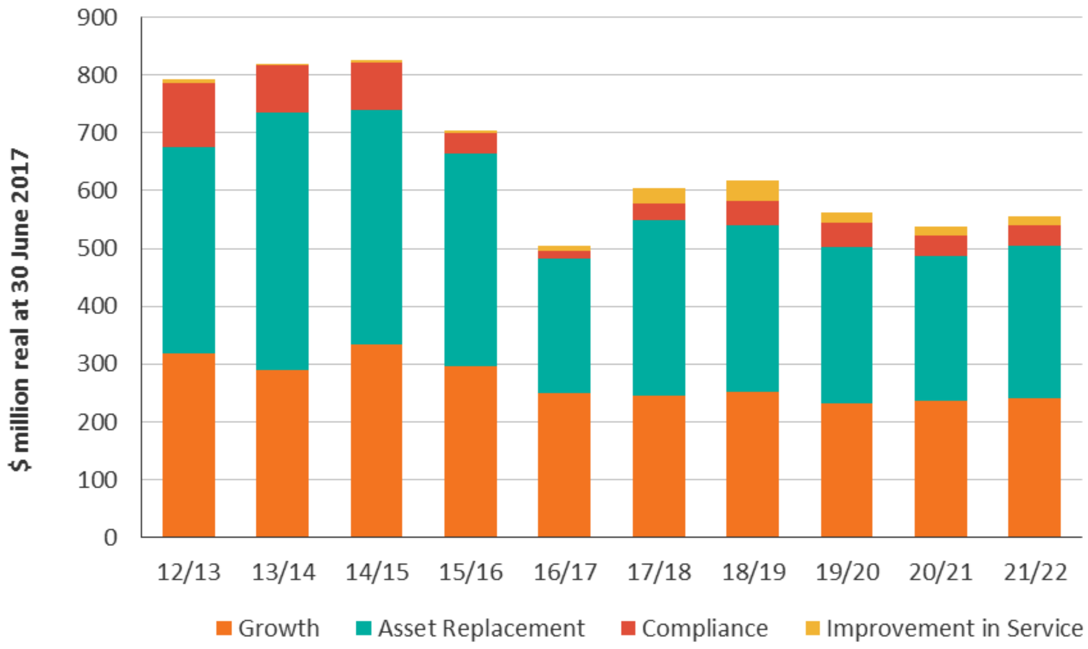
Figure 8.16: Comparison of gross AA4 forecast and AA3 actual capex



676. The increase in capital expenditure in 2017/18 compared to 2016/17 reflects the business returning to a typical level of investment. Capital expenditure levels in 2016/17 were lower than usual for the following reasons:

- the business review and subsequent Business Transformation Program saw the business take stock of its forecast investment, scaling back activities while it investigated more efficient ways to deliver works and considered the most prudent forward-looking investment program
- as shown in Figure 8.17 below, 2016/17 also saw a significant decrease in distribution asset replacement. This was predominantly due to a reduction in expenditure in wood pole management expenditure, following the high levels of investment in previous years to satisfy the Energy*Safety* Order 01-2009.

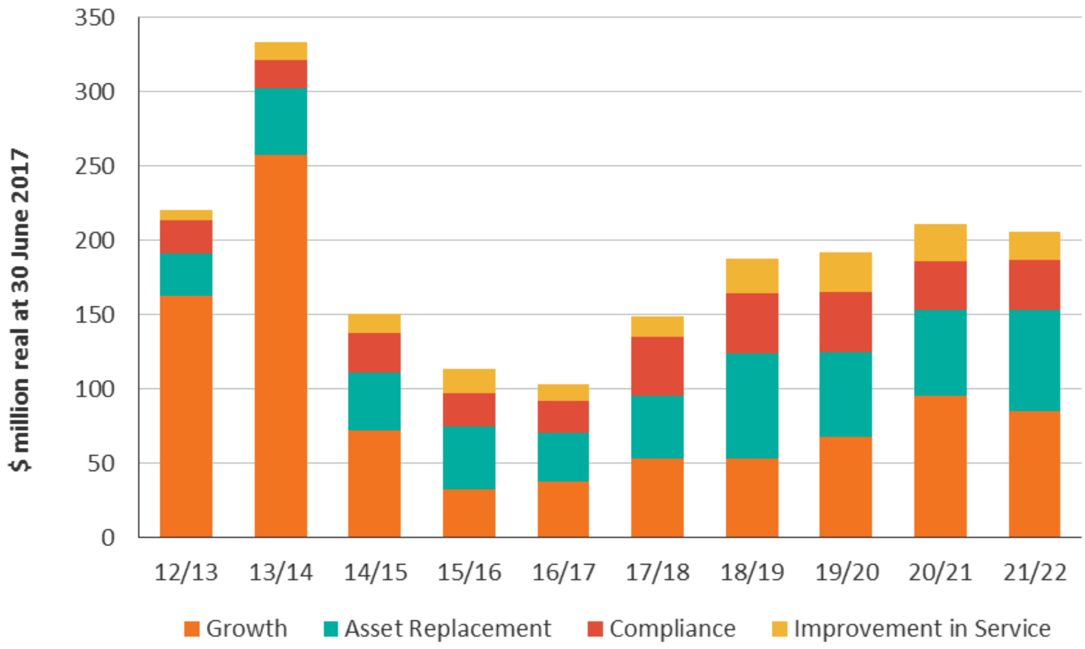
Figure 8.17: Comparison of AA3 actual and AA4 forecast distribution capex by expenditure category, $ million real at 30 June 2017



677. From 2016/17 onwards the mix of distribution asset replacement comprises fewer poles but higher volumes of switchgear, reclosers and meters. Overhead conductor replacement volumes remain at similar levels to those of the AA3 period. We consider the AA4 forecast represents a prudent level of distribution asset replacement that will maintain the current overall network safety risk at a lower cost than incurred during the AA3 period.

678. The decrease in distribution capex is offset to some extent by an increase in investment in the transmission network (see Figure 8.18).

Figure 8.18: Comparison of AA3 actual and AA4 forecast transmission capex by expenditure category, $ million real at 30 June 2017



679. Overall transmission capex across the AA4 period is forecast to be a similar level[148] to that incurred during the AA3 period, although the profile of expenditure over the AA4 period is smoother. The mix of transmission investment has changed, with a more even split between asset replacement and growth-related investment.

680. The main reason for the reduction in growth-related expenditure is the completion of the Mid-West Energy Project (**MWEP**), stage 1 southern section. The MWEP was the single largest growth-related project in the last 30 years, and accounted for 39 per cent of transmission capex during the AA3 period. Western Power currently has no plans to undertake MWEP Southern Section Stage 2 or MWEP Northern Section stage 1 during the AA4 period unless there is sufficient demand from generators in the region.

681. The reduction in growth-related capex is offset by an increase in transmission asset replacement and renewal. The increases in asset replacement compared to the AA3 period is the result of Western Power undertaking transmission works that had to be deferred from the AA3 period in the wake of the Muja transformer failures. The capex increase also includes investment to help reduce the likelihood and impact of a similar major transformer failure in the future. Forecast transmission asset replacement is discussed in further detail in Attachment 8.1.

682. The AA4 transmission capex forecast reflects a balanced program of work, which means customers will benefit from a greater range and volume of transmission projects during the AA4 period, delivered for a similar level of expenditure as in the AA3 period.

683. Corporate capex is required to support Western Power's business operations. The forecast corporate capex includes investment in property, plant and equipment as well as upgrades and replacement of existing ICT systems.

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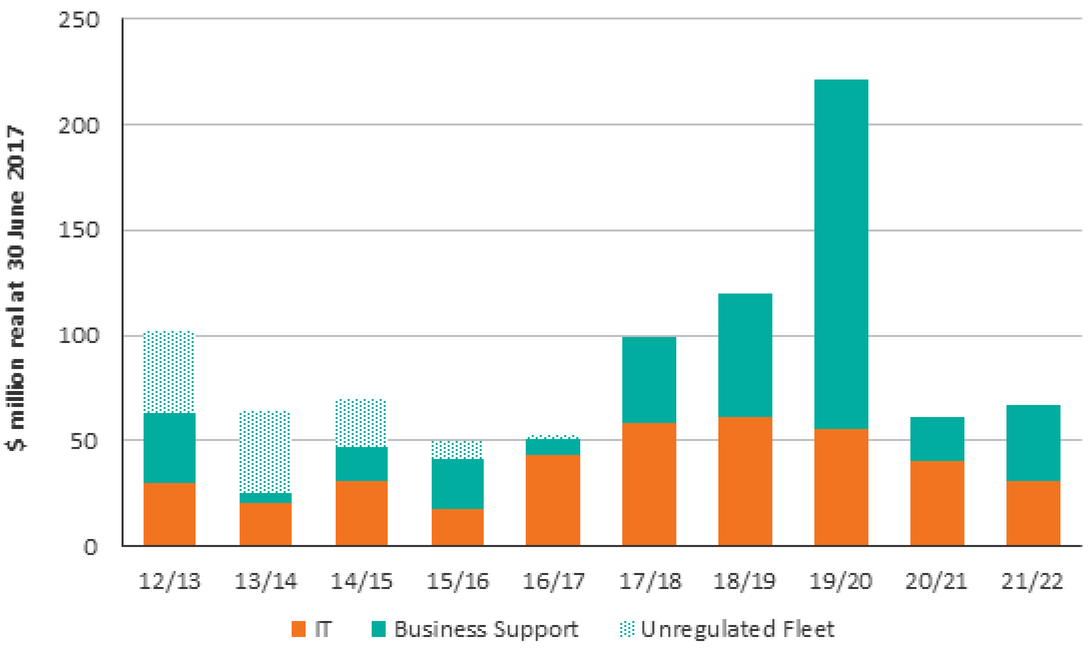
148 AA4 forecast is 3 per cent higher ($25 million) including escalation and indirect costs.

684. Forecast corporate capex for the AA4 period is $230 million (68 per cent) higher than that incurred during the AA3 period[149] (see Figure 8.19). During the AA4 period, Western Power will invest $569 million of capital in corporate support. This represents around 13 per cent of total capex.

Figure 8.19: Comparison of AA3 actual and AA4 forecast corporate capex by expenditure sub-category, $ million real at 30 June 2017[150]



685. The primary driver for this capex increase is the need to rationalise Western Power's portfolio of metropolitan and regional operational depots, many of which are in poor condition.

686. Other corporate real estate projects proposed for the AA4 period include relocation of Western Power's Network Operations Control Centre. The primary driver for the relocation is that the current building is beyond its useful life, with wiring and roofing requiring substantial modernisation. The cost of relocation is seen as prudent as compared to the cost of renovating/overhauling the existing aged building.

687. Most of the relative increase in ICT capex relates to upgrades and replacements of existing ICT systems, which are designed to improve processes and help the business realise the efficiencies identified in our recent Business Transformation Program. Western Power's Business Transformation Program commenced in 2015, with many initiatives having a direct or indirect ICT component.

688. A key outcome of the Business Transformation Program is the business' greater dependence on automation and ICT systems, particularly in the asset management space. Therefore, to ensure the benefits of the business transformation are maintained over the long term, investment in enhancing and maintaining these systems is required.

689. For example, Western Power's enterprise resource planning system, Ellipse, and geographical information system, SPIDA, require upgrades during the AA4 period. Ellipse has not been upgraded since 2010, while

149 The AA3 values used for this comparison includes $112 million of unregulated Fleet capex for comparative purposes

150 The AA3 values used in this chart includes $112 million of unregulated Fleet capex for comparative purposes

SPIDA requires enhancement to provide more accurate and timely analysis of the network – both of which will support the asset management improvements made during the business transformation program.

690. Western Power also proposes to invest in a new customer management system to replace the existing ten-year old system and enable basic customer service capabilities which currently do not exist. During our customer engagement program, customers told us they believed that accurate and timely information is essential for a positive customer experience. The new customer system will integrate customer quotations, contacts, communication channels, fault reporting, meter reading, vegetation and property access management, and operational work orders, providing a single view of customer requirements and improving the accuracy and retrieval of data and customer online self-service.

691. A further change for the AA4 period is that Western Power proposes capital expenditure on fleet be added to the regulated asset base. During the AA3 period fleet was treated as unregulated expenditure, and not included in the RAB. The changes in treatment for the AA4 period means there is a fleet capex component in the AA4 corporate capex forecast.

692. Fleet capex for the AA4 period is $78 million. This compares with $112 million of unregulated fleet capex incurred during the AA3 period (as shown in the shaded segment in Figure 8.19). However, it should be noted that the accounting treatment of light fleet will change in 2019/20. Currently, light fleet vehicles are leased and costs incurred as opex. It is only from 2019/20 onwards that light fleet leasing costs are to be capitalised and added to the regulated asset base. Heavy fleet vehicles are currently purchased, so there will be no change to the treatment of heavy fleet assets.

8.3.1 AA4 capex forecast based on 10-Year Business Plan

693. The expenditure forecast developed for this AA4 proposal are drawn from the forecasts produced for the 2018/19 10-Year Business Plan. While the capex forecasts have been reviewed and reclassified by regulatory expenditure category for this AA4 proposal, the forward program of work was developed as part of the normal planning process. Western Power does not plan network investment by access arrangement period, it is an ongoing annual process.

694. The 10-Year Business Plan is a consolidated view of forecast opex and capex over a rolling 10-year period. The plan outlines network and non-network investment required to meet corporate objectives, customer expectations, regulatory commitments, licensing and other legislative obligations. It is typically refreshed and updated in November/December each year, and is a key part of Western Power's ongoing business planning cycle.

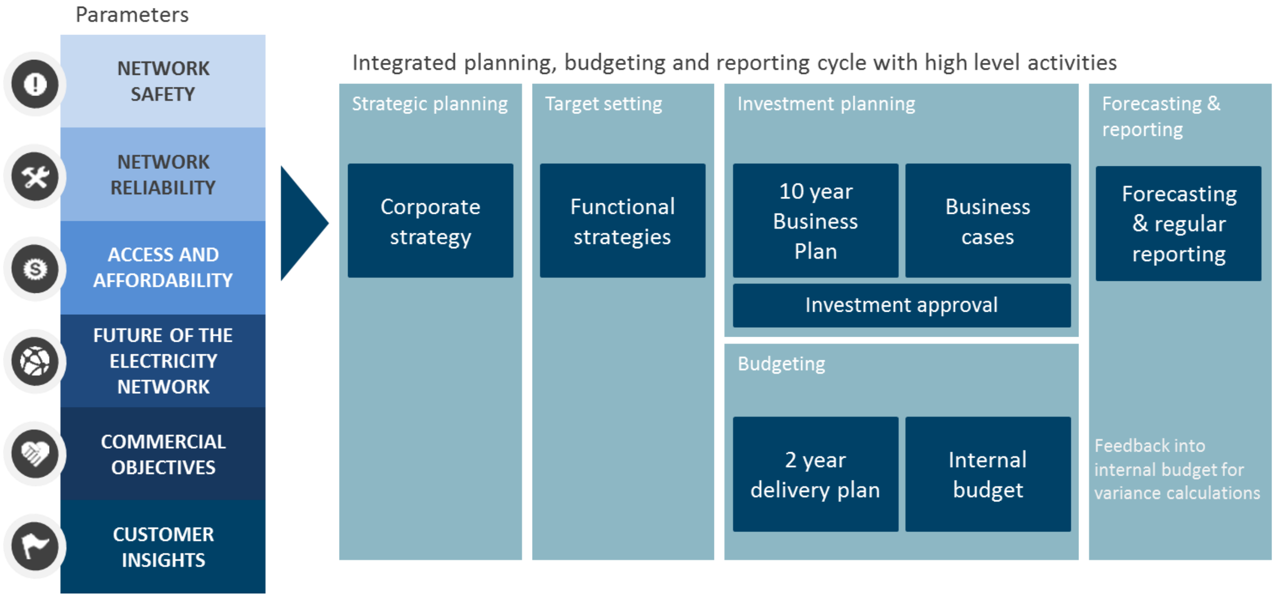
695. Western Power's 10-Year Business Plan was first produced in 2014. The plan was introduced as part of Western Power's response to the changing economic environment and slowdown in growth, which saw the business undertake a strategic review of activities and business processes. The 10-Year Business Plan improves upon the previous approved works program development process by requiring greater integration of network planning, asset management and network delivery functions during its development. The 10-Year Business Plan is a focal point of our investment process, and helps ensure the expenditure we are undertaking is prudent, efficient, and reflects customer expectations.

696. Western Power considers the proposed AA4 capex program is prudent, efficiently minimises costs, and satisfies the Access Code objective. All proposed capex (excluding capital contributions and gifted assets) satisfies the new facilities investment test prescribed in section 6.52 of the Access Code.

8.4 Development of the capex program

697. The AA4 capex forecast has been developed using the business as usual planning process outlined in Figure 8.20. Western Power's investment planning process uses a combination of bottom-up build and top-down assessment, tailored for each investment type/asset class. Insights from our customer engagement program have been incorporated into the forecasting methodology, and have helped shape our plans for the next five years, and beyond.

Figure 8.20: Western Power's investment planning process



698. The planning process is subject to strict governance and is designed to promote prudent and efficient investment. For project costing, we use a commercial estimating system that builds individual cost components from a granular level. This is referred to as a cost build up estimating approach.

699. In developing the network and non-network capex forecasts, Western Power has considered:

- annual long term financial planning processes, which provide top-down guidance based on:
  - financial sustainability of Western Power
  - customer expectations
  - forecast price growth
- historical spend profiles
- risk analysis at an asset and network level incorporating safety and reliability outcomes
- demand management and non-network solutions, incorporating a cost benefit analysis
- the impact of energy demand forecasts and projected customer growth on the requirement for augmentation expenditure
- standard unit rates, where applicable
- asset strategies and asset management plans, which provide the overarching guidance in the development of capital expenditure forecasts
- any known regulatory or legislative changes

- capital and operating expenditure trade-offs
- labour and non-labour escalation rates
- productivity growth.

700. A final top-down review is conducted on consolidated forecasts to ensure they:

- are aligned with investment drivers
- satisfy corporate objectives
- are prudent and efficient
- have been assessed at both a granular and holistic level.

701. Top-down analysis includes financial modelling, historical trend analysis, and consideration of expenditure against key financial parameters such as debt management and price impact. The investment planning process is undertaken annually, and the outputs are captured in Western Power's 10-Year Business Plan. Further information is provided at Confidential Attachment 8.3.

702. For the purpose of the AA4 proposal, Western Power is required to submit its expenditure forecasts by regulatory capital expenditure categories defined by the ERA. These regulatory categories are presented in the AA4 Forecast Capital Expenditure Report provided in Attachment 8.1.

8.4.1 Demand forecasts used to determine this capex forecast

703. The AA4 capex program is based on the forecasts for demand and customer numbers produced in 2016 and updated in 2017. This is because the timing of Western Power's planning cycle means the 2017 forecasts were not available at the time of developing the capex program included in this AA4 proposal. The 2016 and 2017 peak demand, energy consumption and customer number forecasts are provided in Attachment 7.3.

704. In response to the ERA's draft decision, Western Power will go through its annual planning cycle and update the capex program to fully consider the 2017 peak demand, energy consumption and customer number forecasts. We do not expect the integration of the 2017 forecast will have a material impact on Western Power's AA4 period capex forecasts.

705. Therefore, the impact of any significant changes in demand should not materially impact the overall AA4 transmission capex forecast because:

- for the transmission capex program there are few projects that are dependent on the load forecast
- the bulk of the transmission spend is driven by optimised asset replacement, which is agnostic to changes in the load forecast
- the majority of the transmission growth driven investment, that is influenced by changes in the load forecast, is planned for the end of the AA4 period/beginning of AA5 period.

706. Though some transmission line augmentation projects and transmission network investment is driven by localised load growth, we do not expect the local growth forecasts to change between 2016 and 2017 to a degree that would alter the cost or timing of these projects. However, we will review these projects as part of the annual planning cycle and include any variations in our response to the ERA's draft decision.

707. Investment in the distribution network is typically more sensitive to load growth. However, an early assessment of the difference between the 2016 and 2017 demand forecasts (a ~four per cent reduction in

the system peak) would result in only a small adjustment or deferral of load dependent distribution projects. Any necessary adjustments to the AA4 period distribution capex forecast will be assessed as part of our annual planning cycle, and will be factored into our response to the ERA's draft decision.

8.4.2 Adjusting for forecast movements in the market price of labour

708. Western Power has escalated the capex forecast for forecast growth (on a real basis) in the cost of labour. The labour cost escalations were developed by independent experts Synergies Economic Consulting. Synergies' report is provided in Attachment 7.4.

8.4.3 Forecasting capital contributions

709. Western Power charges some customers a contribution towards the cost of connection. It also receives gifted assets from certain connecting parties, such as developers of new residential estates.

710. Contributions are charged where the capital costs associated with a new connection are not fully offset by the incremental revenue we expect to be earned from the connection over the relevant period as outlined in the Contributions Policy. 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.

711. Western Power has modified its Contributions Policy since the AA3 period, which has changed the way capital contributions will be calculated during the AA4 period. A description of the policy changes is provided in Chapter 12 of this AAI.

712. We have forecast AA4 capital contributions using the same assumptions and method used to forecast AA4 period expenditure. For customer driven capex, we have used average historical expenditure and contributions to estimate likely contributions over the period. This forecasting approach is consistent with the Access Code and is appropriate given the uncertainty and limited control we have over customer requirements.

713. We have forecast AA4 capital 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)
- metering.

714. The method for estimating each form of contribution is summarised in the sections below.

Transmission contributions

715. Western Power assumes a 100 per cent contribution for transmission customer driven works. A 42 per cent contribution rate is assumed for all other transmission works. While we assess actual capital contributions on a case-by-case basis, these forecasting assumptions reflect the AA3 average recovery rate for capital contributions from transmission customers.

Distribution contributions

716. Western Power assumes a 50 per cent contribution rate for distribution customer driven works. This reflects the AA3 average recovery rate for capital contributions from distribution customers. This rate

caters for confirmed changes to Contributions Policy such as the revenue offset for residential customers and changes to the DLVCHS[151].

SUPP contributions

717. SUPP contributions are forecast in accordance with a capital and operating cost sharing agreement between State Government, local government and Western Power. Typically, local governments will contribute at least 50 per cent of costs, with Western Power and/or State Government contributing the balance.

718. Western Power assumes a 54 per cent contribution rate for distribution customer driven works. This reflects the AA3 average recovery rate for contributions for the SUPP program.

Gifted assets

719. Western Power forecasts gifted assets based on historical volumes and forward projections from land developers, utilities and government planning agencies. The gifted assets contribution is based on an internal estimate of the fair value of the construction costs, rather than on the actual cost incurred by the third party. This helps to ensure our assets are appropriately valued and not overstated.

Metering contributions

720. Western Power forecast metering contributions based on the historical average of 2013/14 to 2016/17 actuals.

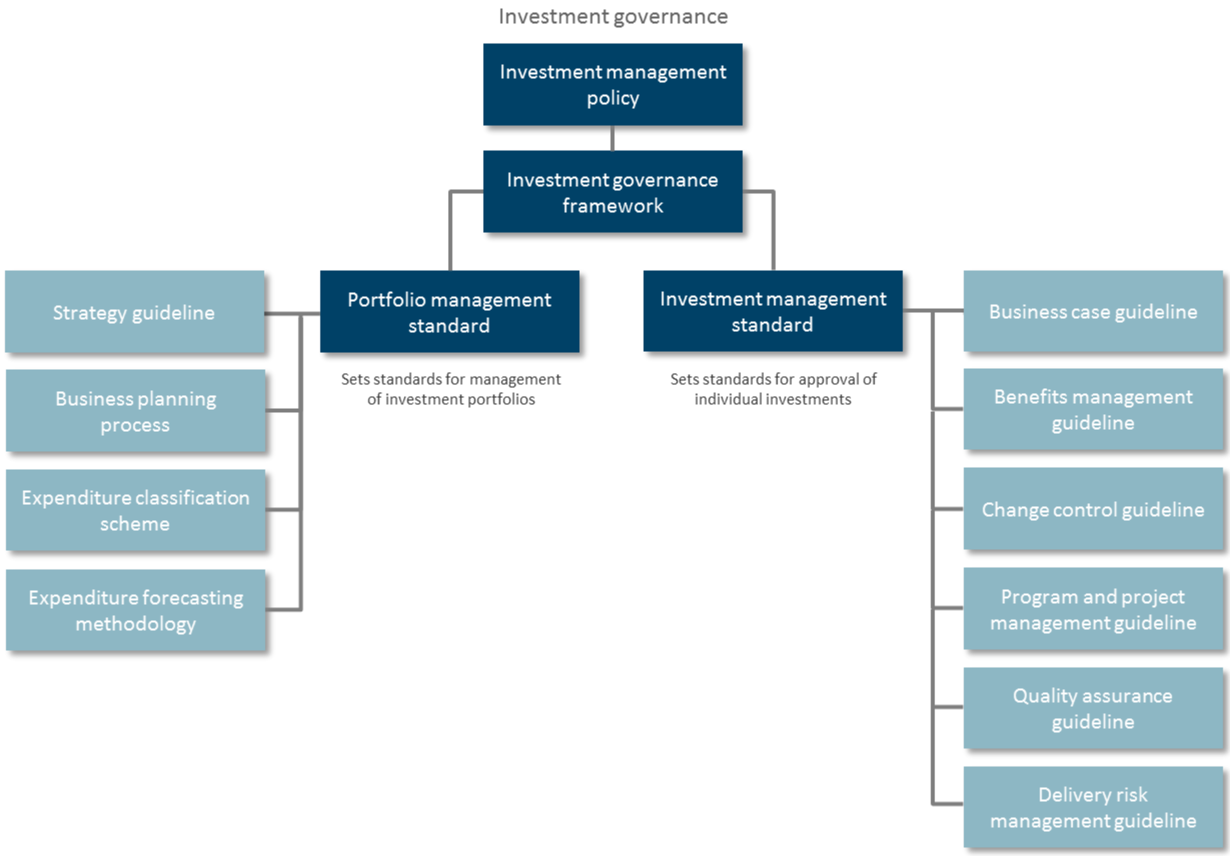
8.4.4 Investment governance

721. Western Power has a comprehensive investment governance structure, to ensure our investment decisions are prudent and efficient. The structure is established through the Investment Management Policy, which is supported by the investment governance framework.

722. Figure 8.21 outlines Western Power's investment governance structure.

151 Distribution Low Voltage Connection Headworks Scheme.

Figure 8.21: Investment governance structure



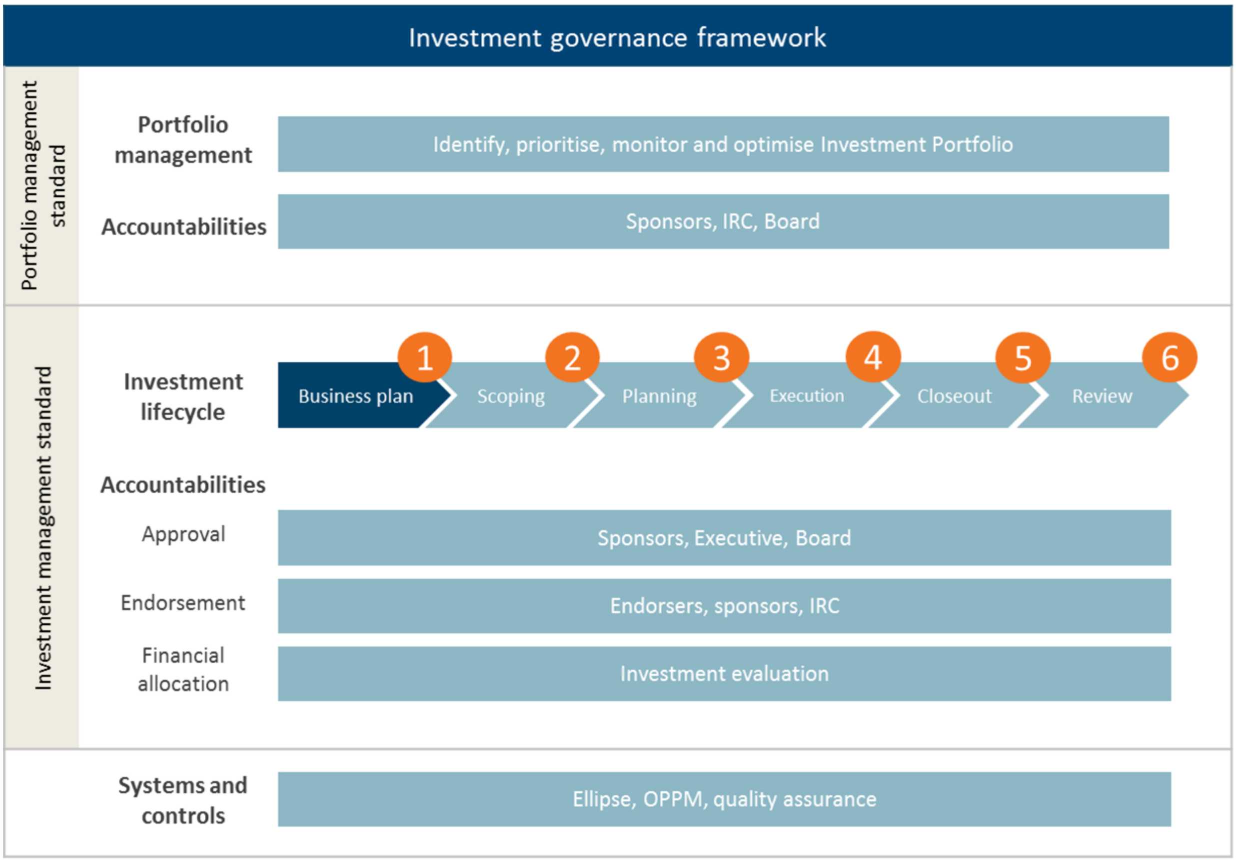
723. The planning process for individual investments is managed through the investment governance framework. This framework outlines the control and governance practices in place to ensure all capital investment proposals are correctly evaluated, approved and, following approval, monitored through their full lifecycle.

724. In summary:

- the development of investments within Western Power is governed by its asset management system
- investment governance is maintained through the investment governance framework and the investment governance structure
- investment approvals (business cases) are governed through the Investment Review Committee (**IRC**). This committee comprises executive managers including the Chief Executive Officer and Chief Financial Officer. Ultimate approval of business cases is dependent on levels of delegated financial authority (**DFA**) issued and updated by the Board.

725. The investment governance framework is outlined in Figure 8.22.

Figure 8.22: Investment governance framework



726. The gated process set out in the framework is designed to implement controls that provide assurance that investments deliver their intended outcomes. The controls are:

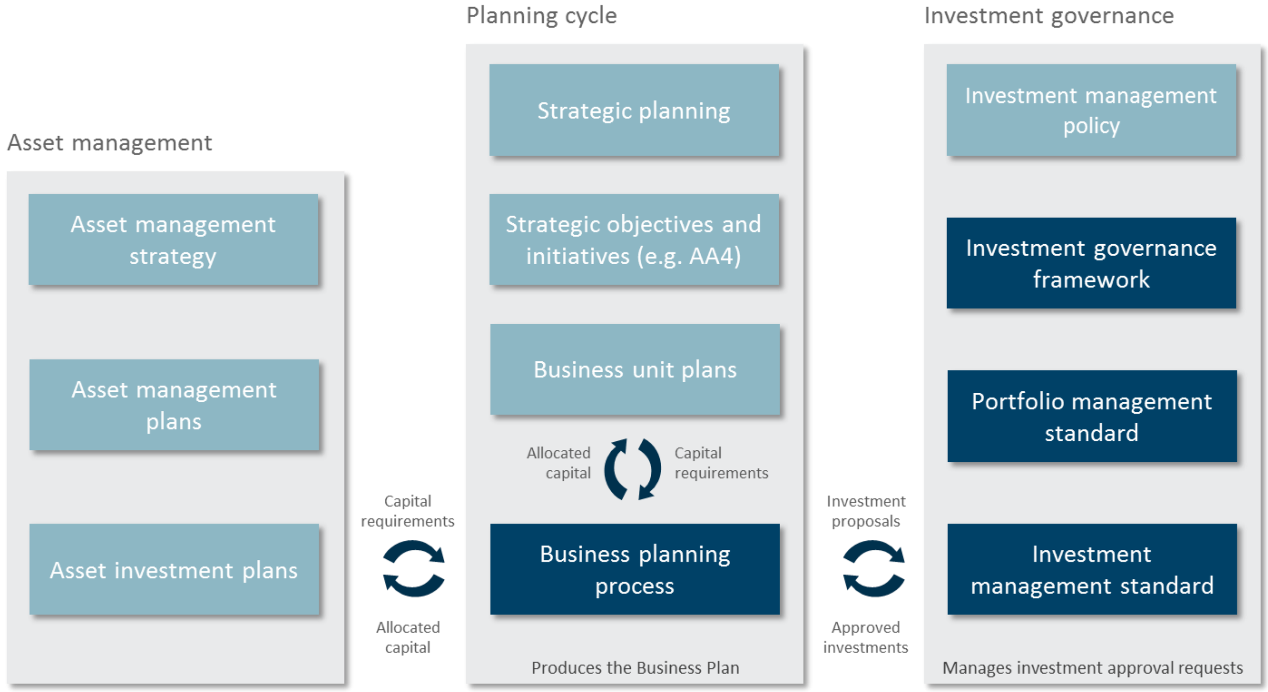
- **approval –** this control is designed to ensure there is commitment from an accountable business owner (or sponsor) to deliver specific benefits. Having the same sponsor through the lifecycle of an investment allows continuity and consistency of the validation process. Sponsor approval is aligned to the limits set out in the DFA
- **endorsement –** this control is designed to validate that the quality standards are met by checking each gate's deliverables against their specifications
- **compliance –** this control is designed to ensure that the expenditure meets regulatory requirements, and verifies that allocation of financial resources is prudent, efficient and optimised within and across expenditure categories.

727. Controls are monitored to ensure an audit trail is kept and financial records are duly maintained.

8.4.4.1 Asset management system

728. The asset management system is aligned with Western Power's corporate strategy and underpins the management of transmission and distribution network assets. This system includes measures that provide for the cost-effective maintenance and development of the transmission and distribution networks. Figure 8.23 illustrates how the asset management system integrates with Western Power's planning and investment framework.

Figure 8.23: Asset management process and investment cycle



9. Weighted average cost of capital

729. This chapter outlines Western Power's estimate of the weighted average cost of capital (**WACC**) for the AA4 period. In the absence of a specific determination for covered electricity networks under section 6.65 of the Access Code, Western Power has estimated the WACC in the AA4 proposal in a manner consistent with section 6.66 of the Access Code.

730. The WACC is the rate of return on investment a company is expected to pay on average to all its security holders to finance its assets. For a regulated business, the WACC is determined using a weighted average of the estimated cost of equity and cost of debt to be incurred over the regulatory period. The cost of equity estimates the return required by shareholders to invest in the network. The cost of debt estimates the interest rate required by debt holders on issued debt (or the interest rate on loans). The weighting reflects that of a theoretical benchmark electricity business and does not necessarily reflect Western Power's actual debt portfolio or ownership structure.

731. The WACC is multiplied by Western Power's asset base to give a return on assets revenue allowance. For asset-intensive businesses such as electricity networks, the return on assets is typically one of the largest building blocks used to calculate target revenue. During the AA3 period, return on assets accounted for 21 per cent ($1,380 million real as at June 2012) of Western Power's revenue.

732. The AA4 period is no exception to this trend. Western Power's return on asset revenue building block for the AA4 period relates to financing investment in an electricity network that provides power to over one million homes and businesses in Western Australia. Achieving a reasonable rate of return is essential to attract the necessary funding from investors and debt providers, so we can continue to maintain and grow the network.

733. Estimating a commercial WACC is a challenging and complex process. For regulated monopolies like Western Power, it is not possible to simply observe the market to determine the cost of equity and debt. Instead, financial models and other market evidence must be used to inform the estimate.

734. Due to the hypothetical and often subjective nature of the estimate, the WACC can be one of the most contentious areas of a regulatory review and has been the subject of many legal and limited merits reviews since 2012[152]. The estimate of the WACC is imprecise and given the uncertainty around what the 'correct' rate of return is, we are proposing a pragmatic and reasoned approach be applied.

735. We have applied the WACC estimating approach used by the ERA in its recent access arrangement decision for the DBNGP[153]. Our WACC estimate has, broadly, adopted the same method for determining the cost of equity and debt that the ERA applied to the DBNGP, however, we have updated the debt and equity parameters to reflect contemporary data. We will also continue to monitor the ongoing limited merit reviews and judicial appeals, and modify our proposal to reflect appeal outcomes where applicable to the WA context.

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152 There have been more than 15 limited merits and judicial review applications made that relate to WACC parameters or gamma since the AER/ERA Rate of Return Guidelines were published in 2013. These decisions were made under the National Electricity Rules and National Gas Rules, but consider the same sorts of approaches applied by the ERA to Western Power in its previous access arrangement reviews and its recent decisions for ATCO Gas and DBP.

153 Appendix 4 Rate of Return, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, ERA, 30 June 2016.

736. In summary, Western Power's WACC approach:

- proposes a benchmark debt gearing ratio of 60 per cent, unchanged from the AA3 period and consistent with recent decisions by the ERA and Australian Energy Regulator (**AER**) for regulated gas and electricity networks
- adopts the ERA's approach to inflation forecasting, using the Fisher Equation to estimate the implied inflation rate from five-year Australian Commonwealth Government Securities (**CGS**) and five-year indexed CGS yields
- adopts annualised yields on a five-year CGS as the proxy for the risk free rate
- adopts the ERA's approach to estimating the equity beta
- calculates the market risk premium (**MRP**) using updated dividend growth model (**DGM**) and long run average MRP estimates
- adopts the ERA's approach to estimating the cost of debt, incorporating a hybrid trailing average with an annual update of the debt risk premium (**DRP**)
- proposes a preliminary gamma of 0.40, with a view to reassessing this value in the light of forthcoming Australian Competition Tribunal and Full Federal Court appeal decisions.[154]

737. We consider the AA4 WACC estimate is a fair and balanced proposal which achieves the Access Code objective and the relevant objectives in section 6.4.

738. When developing the WACC parameters, we have considered the impact on customers and believe we have struck a balance between recovering the business' efficient financing costs, meeting the Code objective, and managing the impact on customers' electricity bills. For example, though adopting a full trailing average cost of debt would better reflect Western Power's debt portfolio, it would materially increase the revenue requirement, resulting in higher electricity prices. Therefore we have adopted a hybrid trailing average, which softens the price impact on customers.

739. Western Power's proposed WACC parameters for the first year of the AA4 period (2017/18) are presented in Table 9.1. Consistent with the ERA's approach, the WACC for the remaining years of the AA4 period will be updated annually in line with new DRP information.

Table 9.1: Indicative WACC parameters for 2017/18

WACC parameter	Western Power estimate for 2017/18
Nominal risk free rate	1.99%
Inflation rate	1.64%
Debt proportion	60%
Debt risk premium (ten-year average)	2.79%

154 The following gamma decisions are pending:

- SAPN's judicial review application to the Full Federal Court in relation to the Tribunal's decision of October 2016.
- Jemena Electricity Network's merits review applications to the Tribunal.
- DBP's merits review application to the Tribunal.

WACC parameter	Western Power estimate for 2017/18
Five-year interest rate swap (effective yield)	2.29%
Return on debt; debt issuing cost (0.125%) + hedging (0.114%)	0.239%
Return on debt	5.32%
Market risk premium	7.5%
Equity beta	0.7
Corporate tax rate	30%
Franking credits (Gamma)	0.4
Nominal after tax return on equity	7.24%
Nominal after tax WACC	6.09%
Real after tax WACC	4.38%

740. The rest of this chapter describes how we have arrived at each of these parameters and the overall WACC point estimate. Further information, including relevant expert reports, is provided at Attachment 9.1.

9.1 Regulatory framework

741. Under the Access Code, the WACC is applied to the projected capital base at the beginning of each year for the purposes of determining the projected rate of return on investment. That rate of return forms part of the building blocks from which target revenue is calculated.

742. The Access Code provisions that apply to our WACC estimate are provided below.

> *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;*

743. Western Power has given regard to the ERA's Rate of Return Guidelines and recent decisions for regulated natural gas networks, however, in the absence of a specific determination for covered electricity networks under section 6.65 of the Access Code, we have estimated the WACC in a manner consistent with section 6.66 of the Access Code, which requires that a WACC determination:

> *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.*

744. The Access Code objective is to promote the economically efficient investment in, and 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.

745. Under section 4.28(a) of the Access Code, if the ERA considers that the Access Code objective and the requirements set out in Chapter 5 (Access Arrangement Content) are satisfied, it must approve the proposed access arrangement.

746. Western Power considers that recent ERA and AER decisions under the national electricity and gas legislation are also relevant. The National Electricity Law (**NEL**) and National Gas Law (**NGL**) require decisions to be made by the regulator in a manner that will, or is likely to, contribute to the achievement of similar overarching objectives to the Access Code objective.[155] In addition, the regulator making a decision under the NEL or the NGL must take into account the revenue and pricing principles, which include that a regulated service provider should be provided with a reasonable opportunity to recover at least its efficient costs.[156] This consideration is similar to the pricing objective in section 6.4(a)(i) outlined above.

747. In addition to these overarching objectives, the allowed WACC under the National Electricity Rules (**NER**) and National Gas Rules (**NGR**) is to be determined such that it achieves the allowed rate of return objective, being:

> *…the rate of return for a [networks service provider] is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the [network service provider].*

748. In this context, we consider that recent decisions by the ERA and the AER, and ongoing legal reviews applying the above overarching objectives provide guidance and are relevant to the consideration of this proposed access arrangement.

9.2 Approach to estimating the WACC

749. To assist with estimating the WACC we sought expert advice from HoustonKemp, who has provided an updated DGM and long run average MRP to support the determination of the cost of equity. A copy of HoustonKemp's report: *A Constructive Review of the ERA's Approach to the MRP* is provided at Attachment 9.1. All other parameters represent our best estimate using the relevant and available data at the time of drafting this AA4 proposal in order to achieve the Access Code and the price control objectives.

750. Where reasonable, and with consideration to the price control objective outlined in section 6.4(a)(i) of the Access Code, we have estimated the cost of equity and debt in line with the ERA's methods presented in recent access arrangement decisions for DPBNGP and ATCO Gas Australia. For the reasons set out below, we consider the proposed approach represents an effective means of achieving the Access Code and price control objectives.

751. The appropriate rate of return on investment is heavily influenced by prevailing market conditions. Further, there are several regulatory decisions, merit reviews and judicial appeals currently underway across Australia, which may provide guidance on the estimated WACC for electricity networks. Western Power therefore reserves the right to provide updated information to the ERA during the course of this access arrangement review and to modify the WACC estimate accordingly. Any new information will be provided

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155 The national electricity objective in section 7 of the National Electricity Law and the National Gas Objective in section 23 of the National Gas Law.

156 NEL, section 7A and 16(2), NGL section 24 and 28(2).

in a timely manner and allow sufficient opportunity for the ERA to make a determination within the time frames prescribed by the Access Code.

752. Western Power's WACC estimate is for the 2017/18 financial year, and is subject to an annual update of the DRP as per the 'hybrid trailing average' method of calculating the cost of debt. Given the ERA's AA4 decision will be made after the first year of the AA4 period commences, where possible, we have used actual 2017/18 data. We propose information relating to the WACC is kept 'live' throughout the access arrangement review process so that the ERA's final decision is informed by the most relevant data available.

753. We have adopted a nominal after tax formulation of the WACC. This formulation is consistent with the ERA's most recent access arrangement decision (under the NGR) for the DBNGP.

754. The nominal after tax WACC formulation is as follows:

$$WACC_{Nom} = r_e \times \frac{E}{E+D} + r_d \times \frac{D}{E+D}$$

where:

- r_e is the cost of equity
- r_d is the cost of debt
- *E* is the proportion of equity used to finance regulated assets by a benchmark electricity network service provider
- *D* is the proportion of debt used to finance regulated assets by a benchmark electricity network service providers
- *E+D* equals 1.

755. Under this approach, the cost of equity (r_e) is determined using the Sharpe-Lintner capital asset pricing model (**SL CAPM**)[157], and uses the following formula:

$$r_e = r_f + \beta \times MRP$$

where:

- r_f is the risk free rate for equity
- β is the equity beta of a benchmark electricity network service provider
- *MRP* is the market risk premium.

756. Consistent with the ERA's recent decisions, the cost of debt (r_d) is estimated as the risk free rate for debt plus a debt risk premium (updated annually) and an allowance for debt raising and hedging costs. The risk free rate for debt is estimated using five-year bank bill swap rate. The cost of debt formula is:

$$r_d = BBSW_5 + DRC + Hedging + DRP^{Trailing}$$

where:

- $BBSW_5$ is the five-year bank bill swap rate
- *DRC* is the debt raising costs

157 The CAPM is widely used for this purpose, and its use is contemplated by clause 6.66(b) of the Access Code. The ERA has favoured the Sharpe- Lintner CAPM (SL CAPM) over all other potential models in its recent regulatory decisions.

- *Hedging* is the cost of hedging (swaps) that converts floating-rate interest payments to fixed-rate interest payments, or vice versa
- $DRP^{Trailing}$ is the ten-year trailing average debt risk premium consistent with the average term of benchmark debt.

757. Some of the WACC parameters set out in the formulae above cannot be measured directly and are subject to imprecision and estimating error. However, the revenue building blocks formula requires a single point estimate of the WACC and its constituent parameters. Therefore, for parameters subject to imprecision (such as the MRP) we have identified a reasonable upper and lower bound and used the mid-point from within that range as the starting point of our AA4 proposal.

758. The following sections explain how we have estimated the values for each WACC parameter.

9.3 Cost of equity

759. The regulated cost of equity is the return required by investors to compensate them for investing in a benchmark efficient entity. It is not possible to observe the return on equity required by investors in the market. This means we must use financial models and other market evidence to inform a reasonable point estimate.

760. We note that in its recent access arrangement decisions for the Mid-West and South-West Gas Distribution Systems[158] and DBNGP, the ERA determined the cost of equity using the SL CAPM which requires the following three parameters to be estimated:

- **the risk free rate** – measures the return an investor would expect from an asset with no risk. The ERA estimates this based on the observed yield on Australian CGS with a five-year term, measured over an averaging period prior to the commencement of the access arrangement period
- **the MRP** – reflects the expected return over the risk free rate that investors require to invest in a well-diversified portfolio of risky assets (assumed to be a ten-year term)
- **equity beta** – measures the sensitivity of a business' returns relative to movements in the overall market return (referred to as systematic or market risk).

761. The ERA and the AER have historically placed most weight on the SL CAPM, and have almost exclusively used this model to determine the cost of equity. We have therefore used the SL CAPM as the foundation model for estimates of the cost of equity for the AA4 period.

762. Table 9.2 summarises Western Power's indicative cost of equity for the AA4 period.

Table 9.2: Estimated cost of equity for the AA4 period

Cost of equity parameter	Western Power's proposal
Risk free rate (average of observed yields of the five-year CGS over agreed averaging period)	1.99% (using a placeholder 20-day averaging period ending on 30 June 2017)
Equity beta	0.7

158 The gas distribution network owned and operated by ATCO Gas.

Cost of equity parameter	Western Power's proposal
Market risk premium	7.5%
Cost of equity	7.24%

763. The cost of equity, particularly the risk free rate, is based on the most recent market data available prior to finalising this proposed access arrangement. The values in Table 9.2 are indicative and will be updated in the ERA's final decision.

764. Western Power's approach to developing the cost of equity parameter estimates is outlined in the following sections.

9.3.1 Risk free rate (for cost of equity estimate)

765. The risk free rate contributes to estimates of the cost of equity. For this estimate, we have adopted the yield on five-year CGS as a proxy for the nominal risk free rate. This is consistent with the approach taken in the ERA's final decision for the DBNGP and in the ERA's AA3 final decision for Western Power.

766. We note the ERA's preference for using a five-year CGS term to estimate the risk free rate is based on its view that there are strong grounds for matching the term to maturity of debt with the length of the access arrangement period. However, we consider this argument may not be valid given the ERA's acceptance[159] that the benchmark efficient entity issues debt over a ten-year term. We also note that the AER continues to adopt a ten-year term for calculating the risk free rate for network businesses operating under the NER.

767. However, given the imprecision around the estimated WACC for the benchmark efficient entity, Western Power will adopt the ERA's five-year CGS method in this AA4 proposal. We have used a placeholder 20-day averaging period to 30 June 2017 (which will be updated prior to the ERA's final decision) and we estimate an indicative nominal risk free rate of 1.99 per cent.

9.3.2 Market risk premium

768. The 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.

769. In its final decision for the DBNGP, the ERA concluded that:

> *…it is not reasonable to constrain the MRP to a fixed range over time*[160]

and

> *… it considers it appropriate to determine a range for the MRP at the time of each decision.*[161]

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159 In its June 2016 decision for the DBNGP, the ERA *adopts a 10 year term for the debt risk premium, consistent with the estimated average term at issuance, which the Authority determines is 10 years*. – paragraph 689, Appendix 4 Rate of Return, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, ERA, 30 June 2016.

160 Paragraph 483, ERA*, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, Appendix 4 Rate of Return, 30 June 2016.

161 Paragraph 484, ibid.

770. In its final decision for the DBNGP, the ERA applied a two-step approach to setting the MRP:

- **establish a range of possible outcomes for the MRP** – the ERA used estimates of the long-run average MRP computed from historical data to form a lower bound of the range, and used estimates arrived at using the DGM to form an upper bound for the range
- **determine a MRP point estimate** – the ERA selected a point estimate from the range using four forward looking indicators of market conditions, and its own judgment.

771. Consistent with the ERA's final decision for the DBNGP, Western Power has determined a range for the MRP and selected a point estimate from this range. We have applied the MRP estimating methodology used by the ERA in its final decision for the DBNGP, with the following variations:

- included 2016 data in the sample of historical excess returns used to estimate the long-run average MRP
- updated the analysis of DGM studies by:
  - providing a prevailing MRP estimate using the ERA's 2-stage DGM
  - including the AER's most recent DGM analysis from its final decision for TasNetworks in April 2017
- solely relied on the (2013) NERA Economic Consulting (**NERA**)[162] data set (rather than Brailsford, Handley and Maheswaran 2012 (**BHM**))[163], consistent with the approach adopted by market practitioners such as Dimson, Marsh and Stanton
- used the longest period possible (1883 to 2016) to ensure the statistical robustness of the MRP estimate
- not applied a 50-50 weighting between arithmetic and geometric estimates of the MRP. Instead, we recommend no weight is placed on geometric means, to avoid introducing downward bias in MRP estimates
- selected the mid-point of our defined range as the point estimate.

772. Using this approach, we conclude the best estimate of the MRP using historical excess returns is 7.5 per cent, which is drawn from a range of 6.8 to 8.2 per cent.

773. This estimate is based on Western Power's analysis and advice provided by HoustonKemp, who we commissioned to review the ERA's MRP estimating approach in its final decision for the DBNGP. The HoustonKemp expert report is provided at Attachment 9.1.

774. The following sections explain how we have arrived at the MRP range and the point estimate.

9.3.2.1 Determining the MRP range

9.3.2.1.1 Lower bound of the MRP range

775. In its final decision for the DBNGP, the ERA estimated the lower bound of the forward looking MRP by reference to the long run average MRP.

162 *The market risk premium: Analysis in response to the AER's Draft Rate of Return Guidelines: A report for the Energy Networks Association*, NERA, October 2013.

163 Pages 237-247, *The historical equity risk premium in Australia: Post-GFC and 128 years of data*, Accounting and Finance, Brailsford, T., J. Handley and K. Maheswaran, 2012.

776. To estimate the long run average MRP, the ERA used:

- five overlapping periods extended through to 2015
- data from BHM and NERA.

777. To set the lower bound estimate, the ERA:

- placed an equal weight on the observed period with the lowest arithmetic mean and the observed period with the highest geometric mean
- assumed that the value of a one-dollar imputation credit distributed, theta, is 53 cents
- estimated the yield on a five-year Commonwealth Government bond as the average of the three-month bill and 10-year bond yields.

778. Western Power's MRP estimate follows a similar approach. However, we have used up-to-date data of the long run average MRP and have placed more weight on the NERA data. We also consider that no weight should be placed on the geometric mean.

779. The way in which our MRP lower bound estimate varies from the ERA's approach in the final decision for the DBNGP is described below.

Extending the five overlapping periods

780. The first change in Western Power's estimate compared to the ERA's approach is that we have extended the five overlapping periods the ERA used (BHM and NERA) through to 2016.

781. Table 9.3 presents estimates for the five overlapping periods using BHM and NERA data extended through to 2016, and arithmetic and geometric means. The estimates we provide differ marginally from the estimates the ERA provided in its final decision for the DBNGP.[164] The methodology used to develop these estimates is described in section 3.1 of the HoustonKemp report.

Table 9.3: Estimates of the MRP: Theta = 0.53 (numbers in brackets represent standard errors)

	Arithmetic			Geometric		
	BHM	NERA	Average	BHM	NERA	Average
1883-2016	6.41	6.77	6.59	5.05	5.40	5.22
	(1.42)	(1.42)	(1.42)	(1.50)	(1.51)	(1.51)
1937-2016	6.19	6.12	6.15	4.32	4.26	4.29
	(2.16)	(2.16)	(2.16)	(2.27)	(2.27)	(2.27)

164 Note that Table 4 and Table 7 in the ERA's final decision for the DBNGP from 2016 are mislabelled. The title to Table 4 states that the nominal and real returns to the market that appear in the table are without imputation credits. In fact, the nominal returns are without imputation credits but the real returns are with imputation credits. Table 7 has the labels for the BHM and NERA estimates around the wrong way.

	Arithmetic			Geometric		
	BHM	NERA	Average	BHM	NERA	Average
1958-2016	6.61	6.61	6.61	4.25	4.25	4.25
	(2.83)	(2.83)	(2.83)	(2.98)	(2.98)	(2.98)
1980-2016	6.30	6.30	6.30	3.98	3.98	3.98
	(3.52)	(3.52)	(3.52)	(3.77)	(3.77)	(3.77)
1988-2016	5.78	5.78	5.78	4.12	4.12	4.12
	(3.25)	(3.25)	(3.25)	(3.70)	(3.70)	(3.70)

782. Part of the reason for the difference lies in the fact that the return to the market in 2016 was relatively high. The gross return to the All Ordinaries from December 2015 to December 2016 was 13.71 per cent. The yield on a five-year Commonwealth Government bond (estimated as the average of the three-month bill and 10-year bond yields) at the end of 2016 was 2.43 per cent. The excess return to the market portfolio (computed as per BHM's method) was 11.28 per cent – considerably above its long-run average. As a result, estimates of the MRP rise with the addition of the 2016 data.

783. Another reason for the difference is that Western Power uses Australian Taxation Office (**ATO**) data on credit yields from 1998 onwards and assumes that prior to 1998 dividends are 75 per cent franked.[165] The ERA in its final decision for the DBNGP assumes dividends are 75 per cent franked both before 1998 and from 1998 onwards, and did not use ATO yields.[166]

784. If we were to apply the ERA's approach in the final decision for the DBNGP to estimate the lower bound for the MRP it would involve calculating a simple average of the estimates computed from the BHM and NERA data presented in Table 9.3. That is, calculating the simple average of:

- the lowest arithmetic mean of 5.78 per cent (from the 1988-2016 period)
- the highest geometric mean of 5.22 per cent (from the 1883-2016 period).

785. However, for the reasons highlighted in the following discussion we have not adopted this approach.

Greater weight on the NERA data

786. Our MRP estimate also varies from the ERA's method in that we have not placed equal weighting on the BHM and NERA data.

165 This is the approach taken by Brailsford, Handley and Maheswaran.

166 Note that the ERA confuses the rate at which dividends are franked with the rate at which credits created are distributed. The two quantities need not be equal. See footnote 438, page 111, Appendix 4 Rate of Return, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, ERA, 30 June 2016.

787. In the final decision for the DBNGP, the ERA employed simple averages of the estimates that it computes using the BHM and NERA data. The ERA's rationale for employing an average of the BHM and NERA data is that it has concerns around the source of dividend yields used in the NERA analysis. The ERA states:

> *'With regard to data quality, the BHM historic series are claimed to be downwardly biased on account of an inadequate adjustment made to the dividend yields employed in the data. To address this perceived issue, in 2013 NERA produced an Australian stock market total return series that readjusted the dividend yields prior to 1957.'*
>
> *'Handley's advice to the AER prepared in October 2014 raised a number of concerns regarding the analysis underlying the NERA (2013) data. In particular, he highlighted a lack of consistency between NERA's source of dividend yields and those employed by Lamberton on which the BHM series was based. Additionally, he highlighted that NERA had not reconciled their adjusted yields with those of Lamberton. The Authority therefore is of the view that the analysis underlying the NERA (2013) data is insufficient grounds to justify the full upward adjustment to the BHM series performed by NERA.*
>
> *Given the uncertainty surrounding the most appropriate adjustment to the market return series, the Authority has used an average of the two series to minimise any potential error with use of either series alone.'*[167]

788. Advice provided by HoustonKemp (see section 3.2.1 of the HoustonKemp report) indicates that concerns regarding the NERA data are unfounded.

789. There is also evidence that experts are leaning towards using NERA data exclusively and have refrained from using BHM's adjustments (to Lamberton's yield data) in their analyses. For example, Elroy Dimson of the London Business School and Cambridge University, and Paul Marsh and Mike Staunton of the London Business School, have not used BHM's adjustments in editions of their *Credit Suisse Global Investment Returns Sourcebook and Yearbook*. Dimson, Marsh and Staunton make clear that the 2016 and 2017 editions of their *Credit Suisse Global Investment Returns Sourcebook and Yearbook* use the adjustments that NERA provides.

790. We have followed the Dimson, Marsh and Staunton method and use, solely, the NERA adjustments. We have not used the BHM adjustments and the BHM data prior to 1958.

No weight on geometric means

791. A further change in our approach compared to the ERA's final decision for the DBNGP is the treatment of arithmetic and geometric means.

792. In its final decision for the DBNGP, the ERA distils estimates of the MRP into a single lower bound by taking an average of the estimate that uses the lowest arithmetic mean and the estimate that uses the highest geometric mean.[168] Advice provided by HoustonKemp[169] highlights that using the geometric mean would unnecessarily introduce downward bias into MRP estimates.

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167 Page 110, Appendix 4 Rate of Return, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, ERA, 30 June 2016.

168 Page 119, Appendix 4 Rate of Return, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, ERA, 30 June 2016.

169 See section 3.2.3 of the HoustonKemp report.

793. Both Lally[170] and NERA[171] also note that Australian regulators never compound an estimate of the weighted average costs of capital that uses the arithmetic mean of a sample of returns and so should avoid completely using geometric means.

794. We have therefore used only the arithmetic mean of a sample of returns to the market portfolio in excess of a measure of the risk free rate to estimate the MRP. We placed no reliance on the geometric mean of the sample.

795. We have also used the longest possible time series of reliable data to provide the most precise estimate of the long-run average in accordance with advice from HoustonKemp.

796. Adopting this approach results in a single estimate of the MRP of 6.77 per cent per annum[172]. Therefore, **6.8 per cent represents the bottom of Western Power's range for estimating the MRP**.

9.3.2.1.2 Upper bound of the MRP range

797. The ERA in the final decision for the DBNGP used DGM analysis to establish the upper bound of the MRP range. We have also used DGM studies to determine our upper bound, however, our DGM analysis varies from the ERA's analysis in that we have:

- updated the DGM model to incorporate market information up to 23 May 2017
- adopted a different interpretation of the DGM estimates used
- included the most recent AER DGM analysis, from its final decision for TasNetworks in April 2017.

798. This is discussed in more detail below.

Updated ERA DGM

799. The ERA adopted the following two stage DGM to estimate the forward-looking return on the market portfolio:[173]

$$P_0 = \frac{m \times \mathrm{E}(D_0)}{(1+k)^{m/2}} + \sum_{t=1}^{N} \frac{\mathrm{E}(D_t)}{(1+k)^{m+t-0.5}} + \frac{\frac{\mathrm{E}(D_N)(1+g)}{k-g}}{(1+k)^{m+N-0.5}}$$

where:

- P_0 is the current price of the All Ordinaries
- m is the fraction of the current year remaining
- D_0 is the dividends on the All Ordinaries expected in the current year
- $E(D_t)$ is the dividend per share expected years into the future

170 Page 31-32, *The cost of equity and the market risk premium*, Lally, M., 25 July 2012.

171 Page 3-12, *The market risk premium: A report for CitiPower, Jemena, Powercor, SP AusNet and United Energy*, NERA, February 2012.

172 This estimate is NERA's arithmetic mean for the period 1883-2016 as presented in Table 9.3.

173 Page 115, Appendix 4 Rate of Return, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, ERA, 30 June 2016.

- k is the return on the market portfolio implied by the model
- N is the year of the furthest out dividend forecast
- g is the long run dividend growth rate which is assumed to be 4.6 per cent, consistent with that adopted by the ERA in the final decision for the DBNGP[174].

800. Further, to reflect the value franking credits contribute to the return on equity an investor receives, the estimate dividends reported by Bloomberg for the All Ordinaries are multiplied by an imputation factor (*IF*), i.e.:

$$1+\theta f\left(\frac{\tau}{1-\tau}\right)$$

where:

- θ theta is the market value of franking credits which is assumed to be either:
  - 0.53 consistent with the ERA's gamma value of 0.4[175] or
  - 0.35 consistent with the network businesses gamma value of 0.25[176]
- f is the proportion of franked dividends which is assumed to be 75 per cent[177]
- τ is the corporate tax rate, i.e., 30 per cent.

Interpreting recent DGM estimates

801. The ERA determined the upper bound of the MRP for the DBNGP by reference to a range of recent DGM estimates. Table 9.4 reproduces the DGM studies considered by the ERA in the final decision for the DBNGP.

Table 9.4: DGM studies used in the final decision for the DBNGP

Study/Author	Date	Dividend yield source	Theta	Risk free rate (%)	Implied MRP (%)
SFG	May 2015	Thomson Reuters I/B/E/S	0.35	2.55	8.82
Frontier Economics	July 2015	Thomson Reuters I/B/E/S	0.35	2.85	8.35
AER	May 2016	Bloomberg	0.6	2.93	7.57 – 8.84
ERA	May 2016	Bloomberg	0.6	1.82	8.12
Estimated range of the MRP consistent with a gamma of 0.4					**7.6 – 8.8**

174 Page 116, Appendix 4 Rate of Return, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, ERA, 30 June 2016.

175 Page 111, Appendix 4 Rate of Return, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, ERA, 30 June 2016.

176 Page 369, *SA Power Networks, Revised Regulatory Proposal* 2015-20, July 2015.

177 Page 111, Appendix 4 Rate of Return, *Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, ERA, 30 June 2016.

802. The ERA adopted a MRP upper bound of 8.8 per cent, which was the highest DGM estimate of the MRP commensurate with a gamma of 0.4.

803. Following HoustonKemp's advice[178], Western Power has adopted an approach to interpreting DGM studies which ensures prevailing DGM estimates are internally consistent with other elements of the ERA's final decision for the DBNGP. Our approach is to:

- ensure all estimates of the market return on equity apply the gamma/theta value determined in the decision
- calculate all estimates of the market return on equity as the margin above the five-year risk free rate, consistent with the ERA's specification of the CAPM.

804. These two variations were made to ensure DGM studies are assessed on a like-for-like basis, and represent a spectrum of reasonable estimates that a rational market participant would rely on in making investment decisions.

805. Table 9.5 presents the recalculated MRP estimates cited in the final decision for the DBNGP, using a gamma value of 0.4 and theta value of 0.53, and a five-year risk free rate.

Table 9.5: Recalculated MRP estimates using the DGM in the ERA's final decision for the final decision for the DBNGP, June 2016 (using a consistent gamma/theta value and 5-year risk free rate)

Study/Author	Date	Decision Implied MRP (%)	Consistent gamma/theta	Consistent gamma/theta & Rf
SFG	May 2015	8.82	9.48	9.90
Frontier Economics	July 2015	8.35	9.00	9.57
AER	May 2016	7.57 – 8.84	7.44 – 8.70	8.03 – 9.29
ERA	May 2016	8.12	8.12	8.12
Estimated range of the MRP consistent with a gamma/theta		**7.6 – 8.8**	**7.4 – 9.5**	**8.0 – 9.9**

806. Adjusting the DGM studies to calculate the expected return on the market portfolio over the five-year risk free rate results in a MRP range of between 8.0 and 9.9 per cent.[179]

Applying more recent DGM studies – April 2017 TasNetworks decision

807. As discussed above, when making its June 2017 DBNGP MRP determination, the ERA had reference to three recent DGM studies (in addition to its own analysis). In our MRP estimate, based on advice from HoustonKemp, we have updated the ERA's studies and added the most recent DGM analysis from the AER's April 2017 final decision for TasNetworks.

178 See section 4.2 of the HoustonKemp report.

179 Table 9 of the HoustonKemp report.

808. In addition, we note that SFG/Frontier Economics have not updated their DGM studies and the mid 2015 studies referred to in the table above will be over two years old by the time of the ERA's draft decision. These studies have therefore not been included in the below table of recent DGM studies of the MRP.

809. The updated DGM analysis is provided in Table 9.5.

Table 9.5: Updated MRP estimates using the DGM, May 2017 (using a consistent gamma/theta value and 5-year risk free rate)

Study/Author	Date	Decision Implied MRP (%)	Consistent gamma/theta	Consistent gamma/theta & Rf
AER[180]	April 2017	6.49 – 7.72	6.39 – 7.63	6.98 – 8.21
ERA	23 May 2017	7.93	7.93	7.93
Estimated range of the MRP consistent with a gamma/theta		**6.5 – 7.9**	**6.4 – 7.3**	**7.0 – 8.2**

810. This results in a MRP range of between 6.5 to 7.9 per cent. However, a number of these studies adopt assumptions inconsistent with the ERA's determination of a 0.4 gamma and a five-year risk free rate. Adjusting the range for these differences results in a MRP range of between 7.0 to 8.2 per cent.

811. We note the ERA's approach of adopting the highest implied MRP estimate from recent DGM studies as the upper bound of the MRP range. Applying this approach results in an **upper bound of the MRP range of 8.2 per cent**.

9.3.2.2 Setting the MRP point estimate

812. The ERA in its final decision for the DBNGP was guided by four forward looking indicators to set the point estimate of the MRP from within the estimated MRP range. The four indicators the ERA used were:

- default spreads on AA bonds (i.e. the DRP on AA bonds)
- dividend yields on the All Ordinaries
- interest rate swap spreads on five-year bonds
- the Australian Stock Exchange (**ASX**) 2000 volatility index (**VIX**).

813. HoustonKemp analysed how effective each of these four indicators are in tracking variation in the MRP over time. HoustonKemp's findings are presented in section 5 of its report. In summary, HoustonKemp found there is some evidence for using default spreads, dividend yields and interest rate swaps as forward looking indicators of the MRP. However, the evidence for a positive relationship between the MRP and return volatility through time is weak. While the current level of the S&P/ASX 200 VIX is low relative to its history over the last 20 years, little weight should be placed on this indicator.

180 Page 222, *TasNetworks distribution determination 2017-19 | Final decision | Attachment 3 – rate of return*, AER, 28 April 2017.

814. HoustonKemp also considered whether there are other forward looking indicators that are relevant when selecting a MRP point estimate. HoustonKemp found that the analysis should include the following indicators:

- **the prevailing bill rate** – evidence of a negative relation between the MRP and the bill rate, coupled with the observation that the bill rate currently lies well below its historical mean, suggests the MRP currently lies above the average level at which it has sat in past years
- **the Wright MRP** – which currently lies at 8.85 per cent, which is close to the midpoint of the MRP range
- **independent expert reports** – reports in 2016 indicate that experts are effectively using an MRP of between 7.8 and 9.6 per cent.

815. Western Power submits that the ERA should include these indicators when determining the return to the market portfolio in excess of the risk free rate.

816. After considering the above forward looking indicators, and investigating other potential indicators, HoustonKemp found no compelling reason to depart from the mid-point of our MRP range (6.8 to 8.2 per cent). **This results in a MRP estimate of 7.5 per cent.**

9.3.3 Equity beta

817. The equity beta represents the degree of systematic risk to which the investors in a benchmark 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 investors can eliminate all other risk by holding a diversified portfolio of assets.

818. There is considerable uncertainty and imprecision involved in estimating the equity beta. However, recent regulatory determinations have converged on an equity beta of 0.7.[181] Therefore, **Western Power has adopted an equity beta of 0.7**, consistent with the ERA's final decision for the DBNGP.

9.4 Cost of debt

819. The cost of debt is the return required by investors on issued debt, and is designed to compensate for credit, maturity, and market risks. Like the cost of equity, the cost of debt provides a premium above the risk free rate, and incorporates debt raising and hedging costs. Unlike the cost of equity, the cost of debt is observable from the market, and recent developments in regulatory WACC methodologies means the cost of debt estimate relies heavily on historical data.

820. Historically, and like estimates of the cost of equity, the cost of debt was measured over a short averaging period just prior to the beginning of an access arrangement period. This was referred to as the 'on the day approach'. There is now broad agreement among regulators and network businesses that the cost of debt should reflect an average over a ten-year historical period. This is known as the 'trailing average' approach. The trailing average, or a hybrid version of the trailing average, has been adopted in all ERA and AER decisions since 2015.

181 The ERA adopted an equity beta of 0.7 in its June 2016 DBNGP decision, and the AER has used an equity beta of 0.7 in all its gas and electricity network decisions since 2012.

821. The trailing average approach estimates the average return that would have been required by investors in a benchmark efficient entity if it raised debt over the ten years prior to the start of the access arrangement period. It assumes the business would have a staggered debt portfolio where ten per cent of its debt is refinanced each year. There is broad consensus among regulators and network businesses that the trailing average (or the hybrid trailing average) is preferable because it reflects replicable and efficient debt management practices.

822. Western Power supports the move to using a trailing average cost of debt. A key consideration is whether to adopt a full trailing average or a hybrid trailing average.

823. A full trailing average reflects Western Power's debt portfolio more closely than the hybrid approach, however, its application would significantly increase Western Power's revenue requirement over the AA4 period. We are mindful of the balance needed to achieve the Access Code and price control objectives, and manage the impact on customers' electricity prices.

824. In its recent decision for the DBNGP, the ERA considered various approaches to estimating the cost of debt, including the on-the-day approach, the trailing average and the hybrid trailing average. The ERA concluded that, overall and weighing up the strengths and weaknesses, the hybrid trailing average approach was preferable.[182]

825. The hybrid trailing average approach combines elements of a trailing average debt risk premium and a prevailing base rate of interest. This approach involves estimating the DRP using an equally weighted 10 year trailing average with a five year swap overlay estimated just prior to the regulatory period.

826. We consider adopting the hybrid trailing average approach to estimate the cost of debt for the AA4 period satisfies the Access Code objective and clause 6.4(a)(i) because:

- the hybrid trailing average is replicable and allows a network, where efficient to do so, to hedge the risk free rate at the start of the regulatory period
- it reflects the fact that the debt risk premium component of the cost of debt cannot be hedged and must be based on a historical trailing average
- consequently the hybrid trailing average will promote economically efficient investment in and operation and use of the network in order to promote competition in upstream and downstream markets and will provide Western Power with an opportunity to recover efficient costs, including a return commensurate with the commercial risks involved.

827. In light of these considerations, and consistent with the ERA's recent decisions, Western Power proposes to adopt the hybrid trailing average approach.

828. Consistent with the ERA's final decision for the DBNGP, we also submit that the trailing average debt risk premium should be updated in each year of the access arrangement period.

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182 See for example the DBNGP Draft Decision (See pages 91 to 97, *Draft Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 - 2020*, ERA, 22 December 2015).

829. The proposed cost of debt formula is provided below.

$$Cost\ of\ debt = BBSW_5 + debt\ risk\ premium + debt\ raising\ costs + hedging\ costs$$

where:

- $BBSW_5$ is the five-year bank bill swap average, calculated over the same averaging period used to estimate the risk free rate for the cost of equity
- *debt risk premium* is measured as the difference between the yield on ten-year broad BBB Australian corporate debt and the ten-year bank bill swap rate, and measured over a trailing historical average without transition, using a combination of data from the Reserve Bank of Australia (**RBA**) and the ERA's revised bond yield approach
- *debt raising costs* are benchmark costs incurred by a business to issue corporate bonds, with the ERA providing an allowance of 12.5 bppa (consistent with previous ERA determinations)
- *hedging costs* are estimated as the sum of:
  - five-year swap floating for fixed for the full amount of debt (4.0 bppa)
  - ten-year cross currency swaps for 35 per cent of debt issuance (4.9 bppa)
  - ten-year fixed to floating AUD swaps for 65 per cent of debt issuance (2.5 bppa).

830. Using this hybrid trailing average approach, Table 9.6 summarises Western Power's indicative cost of debt for 2017/18 and 2018/19.

Table 9.6: Estimated cost of debt for 2017/18

Cost of debt parameter	Western Power's proposal
Benchmark credit rating	BBB-/BBB/BBB+.
Risk free rate for debt (Five-year bank bill swap rate)	2.29% (using a placeholder 20-day averaging period ending on 30 June 2017)
Debt risk premium (10-year average)	2.79%
Return on debt; debt issuing cost (0.125%) + hedging (0.114%)	0.239%

831. Individual parameters of the cost of debt are discussed in the following sections.

9.4.1 Benchmark credit rating

832. The debt risk premium component of the return on debt will reflect the benchmark credit rating. In past access arrangement decisions, the ERA has established the credit rating for Australian electricity and gas businesses is within the BBB band and encompasses BBB-/BBB/BBB+. We accept an appropriate benchmark credit rating for Western Power sits within the BBB band.

9.4.2 Risk free rate (for cost of debt estimate)

833. In its final decision for the DBNGP, the ERA adopted the five-year bank bill swap rate as the proxy for the risk free rate within the hybrid trailing average. Western Power accepts this approach, and submits that the

bank bill swap rate be calculated over the same averaging period as used for calculating the return on equity. The risk free rate will be fixed at the start of the access arrangement period (on the day).

834. In this AA4 proposal, we have used a placeholder 20-day averaging period to 30 June 2017 (which will be updated prior to the ERA's final decision), and estimate an indicative five-year bank bill swap rate of 2.29 per cent.

9.4.3 Debt risk premium

9.4.3.1 Averaging period and annual update

835. Western Power proposes a hybrid trailing average DRP, which will be updated every 12 months. For this AA4 proposal, we submit that the averaging period for the 2017/18 DRP estimate is the period 1 January 2017 to 30 June 2017. An averaging period for the 2018/19 period will be agreed with the ERA and used in the ERA's final decision.

836. For the annual DRP update, we propose the averaging period be as close as reasonably practicable to the beginning of the forthcoming financial year. Having regard to the fact that Western Power must produce an annual price list between February and late April each year of the AA4 period, the time period selected must allow sufficient time for the DRP estimate to be captured, validated, and factored into new revenue targets (and hence prices).

837. The actual averaging periods for the annual updates will be nominated in advance, with the dates remaining confidential. Western Power will nominate the averaging periods for 2019/20 to 2021/22 as soon as practicable after the ERA's final decision is released.

9.4.3.2 Term of debt

838. We propose a term of ten years for the term of debt. This term reflects the term at issuance and is consistent with the efficient financing costs of a benchmark efficient entity with a similar degree of risk to Western Power. A ten-year term to maturity is consistent with the actual observed financing of infrastructure assets and the ERA's analysis in its December 2013 *Rate of Return Guidelines.*[183] The use of term at issuance rather than remaining term to maturity is supported by the AER's analysis in its 2013 *Rate of Return Guideline.*[184]

9.4.3.3 Estimating the DRP

839. We propose the ERA's revised bond yield approach (as per the ERA's final decision for the DBNGP) be used to estimate the DRP.

840. Table 9.7 sets out our estimate of the hybrid trailing average DRP. The value for 2016 has been calculated by:

- adopting the ERA's revised bond yield approach from 1 June 2016 to 31 December 2016
- back solving the RBA numbers for the period 1 January 2016 to 31 May 2016 from the ERA's final decision for the DBNGP.

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183 Paragraph 40, Appendix 3, *Explanatory Statement for the Rate of Return Guidelines*, ERA, 16 December 2013.

184 Page 144*, Explanatory Statement – Rate of Return Guideline*, AER, December 2013.

841. We have estimated the 2017 value using the ERA revised bond yield approach for January to June 2017. Note the figures in Table 9.7 for 2008 through to 2015 are the margins used by the ERA in the final decision for the DBNGP.

Table 9.7: Estimated hybrid trailing average DRP

Year	DRP (%)	Trailing average DRP (%)	Source
2008	3.76	-	RBA
2009	4.62	-	RBA
2010	2.13	-	RBA
2011	2.38	-	RBA
2012	3.17	-	RBA
2013	3.04	-	RBA
2014	2.25	-	RBA
2015	2.07	-	RBA
2016	2.56		RBA to end of May 2016 and ERA method for the rest of the year
2017	1.95	2.79	ERA method (01/01/2017 to 30/06/2017 – to be updated for a full year during decision process)

9.4.4 Debt raising and hedging costs

842. Debt raising and hedging costs are transaction costs incurred each time debt is raised or refinanced. Debt raising costs may include underwriting fees, legal fees, company credit rating fees, and other transaction costs. Debt raising costs are an unavoidable aspect of raising debt that would be incurred by a prudent service provider acting efficiently.

843. Western Power has incorporated the direct components of debt raising costs, following the method outlined in the Allen Consulting Group (**ACG**) 2004 report. This will result in an allowance of 0.125 per cent being incorporated into the cost of debt. This is consistent with the ERA's approach in its final decision for the DBNGP.

844. We have also incorporated a hedging allowance of 0.114 per cent into the cost of debt estimate. This allowance acknowledges the difficulty in hedging the exposure to movements of the risk free rate and is consistent with the ERA's approach.

9.5 Gearing

845. Gearing represents a ratio of the value of debt to total capital (debt plus equity). It is used to weight the return on debt and the return on equity when calculating the WACC.

846. Western Power have proposed a gearing ratio of 60 per cent debt, 40 per cent equity. A 60 per cent debt gearing ratio is consistent with recent Australian regulatory decisions[185], and is the ratio applied by Western Power during the AA3 period.

9.6 Forecast inflation

847. Forecast inflation is used by the ERA to convert the nominal after tax WACC to a real after tax WACC. Western Power has adopted the ERA's approach to forecasting inflation, which is to use:

> *the Fisher equation and the observed yields of 5-year Commonwealth Government Securities (CGS) (which reflect a market based estimate of the nominal risk free rate) and 5-year indexed Treasury bonds (which incorporate a market based estimate of a real risk free rate)*[186]

848. Adopting the ERA's approach results in a forecast inflation rate of 1.64 per cent for the 20 days to end of June 2017.

9.7 Gamma

849. Gamma is the value of franking credits distributed to investors. Gamma (y) is the product of two components: the distribution ratio (F) and utilisation rate or 'theta' (θ):

$$y = F \times \theta$$

where:

- F represents the proportion of franking credits that are distributed to shareholders by attaching them to dividends
- θ is the value of each franking credit

850. The estimate of gamma has been the subject of some contention in recent Australian regulatory decisions, with network businesses consistently proposing a gamma value of 0.25, and the ERA and AER setting a value of 0.40. As a result, the estimate of gamma under the NER and NGR has been the subject of several limited merits reviews by the Australian Competition Tribunal (**Tribunal**), with the following outcomes:

- February 2016 – the Tribunal found in favour of the NSW networks Ausgrid, Endeavour Energy, Essential Energy that gamma should be **0.25**
- July 2016 – the Tribunal found in favour of ATCO Gas Australia that gamma should be **0.25**
- October 2016 – the Tribunal found in favour of the AER (against SA Power Networks) that gamma should be **0.4**.

851. Following these Tribunal decisions, the AER applied to the Full Federal Court for judicial review of its April 2015 decision for the NSW networks. SA Power Networks also applied to the Full Federal Court for judicial review of the AER's October 2015 decision on its regulatory revisions.

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185 A 60 per cent debt gearing ratio has been adopted in both the ERA's and AER's rate of return guidelines, and was applied in the ERA's DBNGP final decision, and its September 2015 ATCO Gas Australia amended final decision.

186 Page 32, *Rate of Return Guidelines*, 16 December 2013.

852. In May 2017, the Full Federal Court completed its judicial review of the AER's April 2015 NSW networks decision, finding that the AER was not wrong to determine a gamma of 0.40. The outcome of the SA Power Networks judicial review has not yet been handed down at time of writing.

853. Further, the Victorian electricity distribution networks providers have lodged an appeal with the Tribunal on the AER's May 2016 gamma determination of 0.40. Dampier to Bunbury Pipeline (**DBP**) also awaits a Tribunal decision on the ERA's gamma determination in its recent access arrangement review.

854. Although the Access Code does not contain a specific rule relating to the estimate of gamma (as is the case in the NER and the NGR) the overarching objectives reflected in the Access Code objective and the price control objectives require similar considerations to the objectives in the national framework.

855. The estimate of gamma is an industry-wide parameter and we consider the recent regulatory decisions and outstanding legal reviews are relevant to Western Power's AA4 proposal.

856. As a result of the ongoing legal reviews noted above, there remains considerable uncertainty around which gamma estimate best meets the Access Code objectives and the relevant price objectives. In light of this, **Western Power submits a gamma value of 0.40**, which is consistent with the most recent Full Federal Court decision. However, we consider this a preliminary estimate, and reserve the right to update and/or revise our gamma estimate pending the outcome of the ongoing judicial and limited merits reviews of this issue.

9.8 Summary of WACC parameter estimate

Table 9.8: Summary of Western Power's WACC estimate

WACC parameter	Western Power estimate
Nominal risk free rate	1.99%
Inflation rate	1.64%
Debt proportion	60%
Debt risk premium (ten-year average)	2.79%
Five-year interest rate swap (effective yield)	2.29%
Return on debt; debt issuing cost (0.125%) + hedging (0.114%)	0.24%
Return on debt	5.32%
Market risk premium	7.5%
Equity beta	0.7
Corporate tax rate	30%
Franking credits (Gamma)	0.4
Nominal after tax return on equity	7.24%

WACC parameter	Western Power estimate
Nominal after tax WACC	6.09%
Real after tax WACC	**4.38%**

10. Annual revenue requirement

857. This chapter describes how Western Power has calculated its revenue requirement for the AA4 period. It includes the forecast target revenue and annual revenue caps.

858. This chapter also outlines the form of price control and revenue components, including calculation of Western Power's regulated asset base, tax asset base, adjustments under regulatory incentive/adjustment mechanisms, and other revenue items.

10.1 Regulatory framework

859. Under the Access Code, an access arrangement may contain any form of price control provided it meets the price control objectives. Section 6.2 of the Access Code states:

> *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).*

860. The price control objectives are defined in Section 6.4 of the Access Code:

> *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).

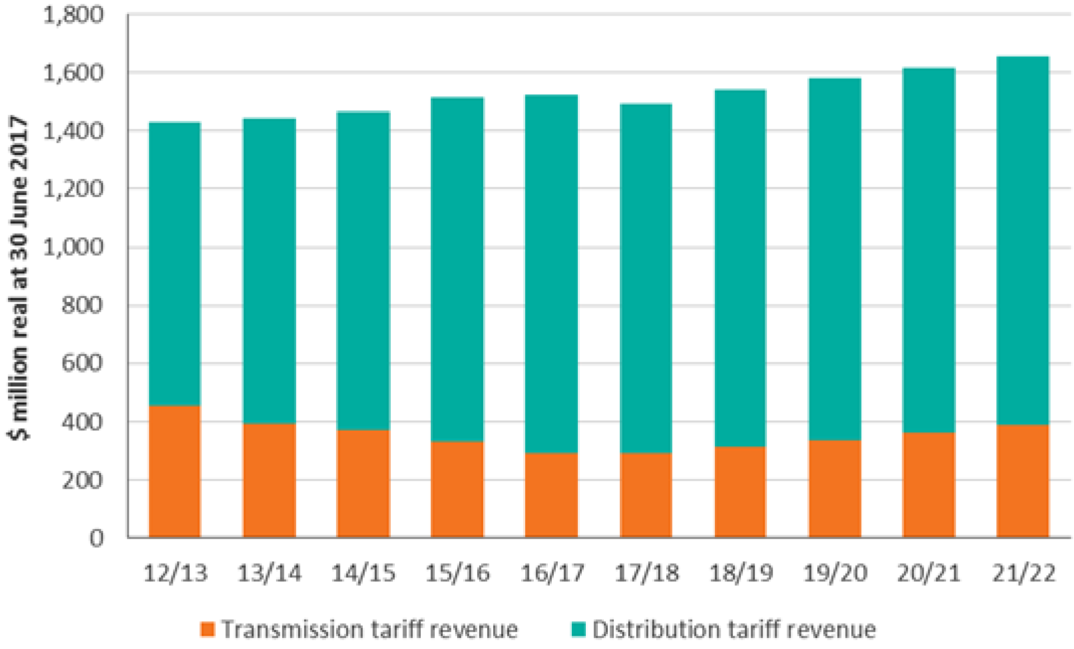
10.2 Overview of revenue requirement

861. Western Power will recover $7,888 million of revenue via reference tariffs during the AA4 period. This is $510 million (6.9 per cent) more than tariff revenue recovered during the AA3 period (see Table 10.1 and Figure 10.1)

Table 10.1: AA4 target revenue, $ million real at 30 June 2017

Target revenue	AA4 period (proposed)
Transmission tariff revenue	1,687.4
Distribution tariff revenue	6,200.3
Total	**7,887.7**

Figure 10.1: Comparison of target revenue for the AA3 and AA4 periods, $ million real at 30 June 2017



862. As per the AA3 period, we propose the revenue cap form of price control be retained for the AA4 period, and that the building block methodology is used to calculate target revenue. We propose to move to a post-tax nominal modelling approach. This method is consistent with the approach taken by the ERA in its recent gas decisions and the AER in all recent gas and electricity decisions.

863. AA4 target revenue includes $822 million (nominal) for the TEC. Western Power pays the TEC to State Government to contribute towards maintaining the financial viability of Horizon Power under Part 9A of the *Electricity Industry Act 2004*. The TEC amount is gazetted by State Government each year and is included in target revenue under sections 6.4(a)(vii) and 6.37A of the Access Code.

864. AA4 target revenue also includes $556.2 million from the adjustment mechanisms that were in place during the AA3 period. This revenue adjustment is made up of:

- $272.6 million from the GSM, as a result of substantial operating efficiencies achieved during the AA3 period
- $255.1 million from the SSAM, as reward for service performance over the AA3 period
- $19.7 million for unforeseen events, comprising costs associated with the EMR
- $8.8 million under the D-factor, for recovery of non-capital costs incurred at Bremer Bay and Ravensthorpe to defer capital expenditure.

865. These positive adjustments under the GSM, SSAM and unforeseen events, are offset by a $39.5 million negative adjustment under the IAM, to return revenue recovered for forecast growth expenditure not undertaken during the AA3 period.

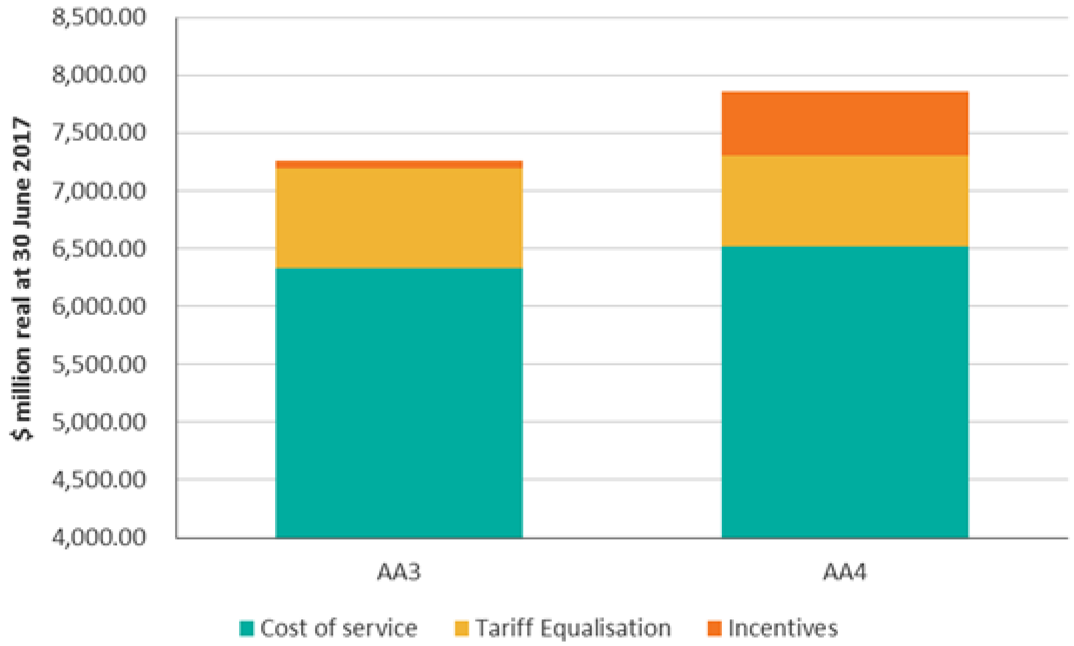
866. The GSM adjustments were a direct result of the targeted efficiency improvements Western Power delivered during the AA3 period, culminating in the Business Transformation Program, which has delivered $330 million in cost savings over the AA3 period. As a result, Western Power is now operating at a greater level of efficiency than in the past. While the GSM rewards from the AA3 period are substantial, as a result

of delivering the significant reductions in our opex, our forecast opex for the AA4 period is much lower. This has ensured that our customers received the majority of the rewards under this mechanism.

867. Western Power is also unlikely to accumulate a similar magnitude of rewards under the SSAM during the AA4 period than it did during AA3. This is because the SSAM targets Western Power is proposing for the AA4 period are set at a higher standard than during AA3. In addition the AA4 forecast expenditure program is lower than that of the AA3 period and is designed only to maintain current overall service levels.

868. Target revenue associated with Western Power's cost of service during the AA4 period is $6,517.3 million. This is only three per cent more than cost of service revenue during AA3. (see Figure 10.2)

Figure 10.2: Comparison of AA3 v AA4 revenue building blocks, $ million real at 30 June 2017



869. Cost of service revenue excludes TEC and adjustments from prior periods. It represents the forecast revenue that results from the proposed access arrangement and services Western Power intends to provide during the AA4 period, including return on and return of capital.

870. The three per cent increase in cost of service is primarily due to the larger regulated asset base. As described in Chapters 7 and 8, forecast operating and capital expenditure for the AA4 period is lower than that incurred during the AA3 period. This reflects the efficiencies achieved during the AA3 period, and the customer-focused approach we have taken to developing the AA4 revenue requirement.

871. Details of the revenue building blocks are provided in the remainder of this chapter.

10.3 Form of price control

872. Western Power will retain the revenue cap form of price control for transmission and distribution services during the AA4 period. We will retain the charging criteria form of price control for ancillary services, such as high load escorts.

873. As per the AA3 period, the revenue cap will apply to all services Western Power provides to transmit and distribute electricity, whether they are reference or a non-reference service. The revenue cap will also cover some metering services required under the Metering Code, such as scheduled meter reading.[187]

874. Non-reference services under the revenue cap are services that are similar to an existing reference service, but have been altered in some way at the request of the customer. For clarity, we define all reference and non-reference services that fall under the revenue cap as **revenue cap services.** These services are:

a. connection services
b. exit services
c. entry services
d. bi-directional services
e. standard metering services as defined in the most recent Model Service Level Agreement (2006) approved by the ERA under the *Electricity Industry Metering Code 2012*
f. streetlight maintenance on Western Power owned assets

875. Ancillary services (such as high load escorts) are defined as **non-revenue cap services**, as the revenue associated with these services are not covered by the revenue cap. Non-revenue cap services are always non-reference services.

876. The form of price control for the AA4 period is detailed in the proposed access arrangement, including the price control formulae required to calculate the transmission and distribution caps for revenue cap services.

877. We have retained the revenue cap as we consider it provided an effective form of price control during the AA3 period. The revenue cap satisfies the price control objective described in section 6.4 of the Access Code as it:

- 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 (see Chapter 11), which sets the revenue cap for each year

878. Revenue cap regulation is also consistent with the form of price control applied to most other regulated electricity transmission and distribution businesses in Australia.

879. Western Power will charge non-revenue cap services directly to the customer that is receiving the service. Charges for non-revenue cap services are set using the criterial detailed in clause 5.1.2(b) of the proposed access arrangement, which requires that charges are:

i. negotiated in good faith;
ii. consistent with the Access Code objective; and
iii. reasonable

187 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.

880. 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-revenue cap services in the AA3 period.

881. The ERA is not required to approve tariffs or charges for non-revenue cap services. The forecast costs for providing non-revenue cap services are not included in the building blocks target revenue used to calculate the annual revenue caps for revenue cap services.

882. 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. Prices for extended metering services are detailed in the metering code model service level agreement. For other non-revenue cap services, we will negotiate individually with customers consistent with the charging criteria.

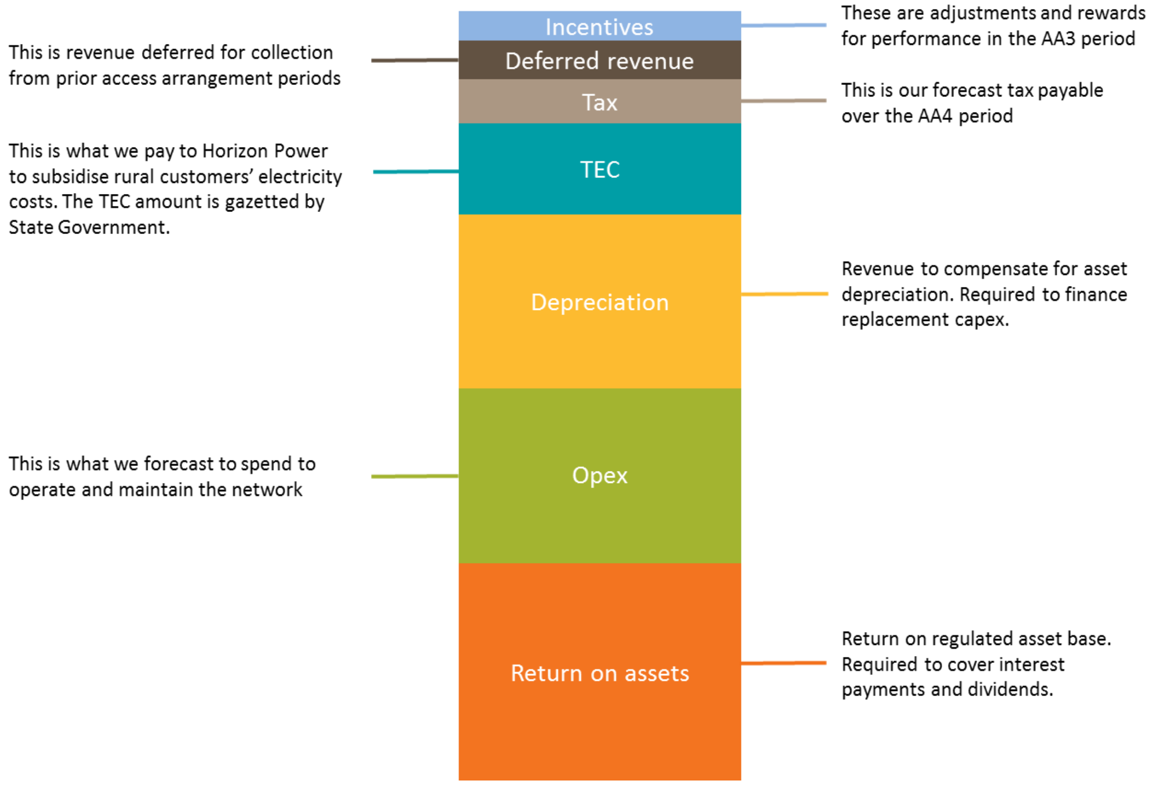
10.4 Use of the building blocks method

883. We have applied the building blocks method to determine target revenue and the revenue caps for the AA4 period. This same method was used to determine target revenue for the AA1, AA2, and AA3 periods. 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. The building blocks method is also prescribed in the National Electricity Rules. [188]

884. We have determined the target revenue in each year of the AA4 period with reference to approved total costs, as provided for in section 6.2(a) of the Access Code. Under the building blocks method the approved total costs are the building blocks, which when added together, determine target revenue. Target revenue is determined separately for the transmission and distribution system. We determine target revenue on a post-tax basis. Figure 10.3 outlines the revenue building blocks.

188 Sections 6.3 and 6A.5.4.

Figure 10.3: Western Power's revenue building blocks



885. Table 10.2 provides cross-references to the sections of this initial submission that discuss and justify our proposal for each of the building blocks.

Table 10.2: Cross-references to building block information in this AAI

Revenue building block	Section of this AAI
Return on investment (WACC)	Chapter 9 and section 10.8 (in this chapter)
Forecast operating expenditure	Chapter 7 and section 10.11 (in this chapter)
Return of capital (depreciation)	Section 10.9 (in this chapter)
Tax	Section 10.15 (in this chapter)
Revenue under AA3 adjustment mechanisms	Section 10.12 (in this chapter)
Revenue deferred from prior AA periods	Section 10.14 (in this chapter)

10.5 Revenue modelling

886. At a high level, Western Power's revenue model determines a revenue requirement for each building block:

- required return on assets (including a return on working capital)
- depreciation
- forecast operating expenditure

- deferred revenue recovery
- regulatory adjustments (incentives and forecast vs actual adjustments)
- forecast tax calculation
- the TEC.

887. A smoothed average price path is then applied to determine the annual revenue caps such that the revenue caps are equal (in present value terms) to the building block revenue requirement.

888. The revenue model implements this calculation and incorporates the following high-level assumptions:

- revenue modelling occurs on a nominal post-tax basis
- all expenses are modelled on an as-incurred basis
- end of year timing for modelling revenues and expenses
- separate modelling of the transmission system and distribution system.

889. The revenue model is provided at Attachment 10.1.

10.6 Regulated asset base

890. The regulated asset base (**RAB**) is one of the largest inputs into the target revenue calculation. It is used to derive both the return on assets and depreciation building blocks. In determining the forecast AA4 RAB, we have calculated the value of the closing AA3 RAB using the same roll forward method used in previous access arrangement periods (AA1, AA2, AA3).

891. The **AA3 closing RAB** calculation uses the following method:

- *start with* the opening RAB at the commencement of AA3
- *adjust* this RAB to account for:
  - the difference between any estimated capital expenditure included in that value, and actual capital expenditure undertaken in the preceding access arrangement period; and
  - the difference between any forecast inflation included in that value, and actual inflation observed in the preceding access arrangement period; and
- *add* the value of capital expenditure (net of contributions) incurred from 1 July 2012 to 30 June 2017
- *deduct* the value of disposals that occurred and forecast depreciation from 1 July 2012 to 30 June 2017.

892. The estimate of the **AA4 closing RAB** considers:

- forecasts of new facilities investment (capex)
- forecasts of capital contributions
- inflation assumptions
- forecasts of depreciation
- economic lives of assets.

893. Table 10.3 shows the closing AA3 RAB and our estimate of the closing RAB for AA4, split by transmission and distribution.

Table 10.3: Western Power closing AA3 and forecast closing AA4 regulated asset base, $ million real at 30 June 2017

Regulated asset base	Estimated closing value for AA3 at 30 June 2017	Forecast closing value for AA4 at 30 June 2022
Transmission RAB	3,131.8	3,542.2
Distribution RAB	5,834.9	6,871.9
Total	**8,966.7**	**10,414.1**

894. Details of the RAB calculations are provided in Attachment 10.2. Below is a summary of the key points:

- we roll forward the RAB over AA4 based on our forecast of new facilities investment and capital contributions. We use this capital base in determining our target revenue for AA4
- we have made minor changes to the economic life for meters and services (reducing from 25 years to 15 years) to better reflect the life of these assets for new facilities investment undertaken in the AA4 period
- no asset disposals are forecast over the AA4 period.

895. Table 10.4 and Table 10.5 shows the roll forward of the transmission and distribution RABs for the AA4 period.

Table 10.4: Transmission RAB roll forward, $ million real at 30 June 2017

Transmission	2017/18	2018/19	2019/20	2020/21	2021/22
Opening RAB	3,131.8	3,183.9	3,277.4	3,396.1	3,473.8
Net Capex	165.8	210.7	245.6	216.0	212.7
Less forecast depreciation	113.7	117.2	126.8	138.2	144.3
Closing RAB	3,183.9	3,277.4	3,396.1	3,473.8	3,542.2

Table 10.5: Distribution RAB roll forward, $ million real at 30 June 2017

Distribution	2017/18	2018/19	2019/20	2020/21	2021/22
Opening RAB	5,834.9	6,080.8	6,320.0	6,582.2	6,715.3
Net Capex	509.5	520.0	557.4	431.3	445.7
Less forecast depreciation	263.6	280.8	295.2	298.3	289.1
Closing RAB	6,080.8	6,320.0	6,582.2	6,715.3	6,871.8

10.7 Tax asset base

896. The tax asset base (**TAB**) is a key input into the calculation of the tax building block. We have calculated the TAB using the roll-forward method. As per the AA4 closing RAB, the forecast AA4 TAB calculation considers:

- forecasts of new facilities investment
- forecasts of capital contributions
- inflation assumptions
- forecasts of depreciation
- economic lives of assets.

897. We have used the same inflation assumptions as used for determining the AA4 weighted average cost of capital (**WACC**). Forecast capex over the AA4 period is in real dollars at 30 June 2017. Depreciation for the TAB is calculated using the diminishing value method.

898. Table 10.6 presents the closing AA3 and AA4 TABs, split by transmission and distribution, in **nominal dollars**.

Table 10.6: Western Power closing AA3 and forecast closing AA4 tax asset base, $ million nominal

Tax asset base	Estimated closing value for AA3 at 30 June 2017	Forecast closing value for AA4 at 30 June 2022
Transmission TAB	2,441.6	2,905.5
Distribution TAB	5,101.9	6,288.6
Total	**7,543.5**	**9,194.1**

899. Details of the TAB calculation, including the associated forecast depreciation and tax asset lives, is provided in Attachment 10.2.

10.8 Return on capital

900. Western Power receives a return on the value of its RAB. This return on capital is one of the largest revenue building blocks. While there are many different ways to estimate the return on capital, we have chosen a method in this submission that limits the price impact on customers. The return on capital amount that Western Power is eligible to receive is determined by multiplying the value of the opening RAB in each year by the WACC for that year.

901. During the AA4 period, the WACC will vary each year as a result of the annual update of the debt risk premium.[189] For the purposes of this AA4 proposal, we have used the 2017/18 WACC estimate of 6.09 per cent post-tax nominal for the whole AA4 period. The impact of annual changes in the WACC during the AA4 period will be reflected in Western Power's annual revenue adjustment and resulting price list. Table 10.7 and Table 10.8 show Western Power's indicative return on capital allowance.

189 Refer to Chapter 9 for details of the annual WACC adjustment.

Table 10.7: Transmission return on capital allowance, $ million nominal

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening RAB	3,131.8	3,236.1	3,385.7	3,565.9	3,707.3
Post-tax nominal WACC	6.09%	6.09%	6.09%	6.09%	6.09%
Indicative return on capital	190.7	197.1	206.2	217.1	225.7

Table 10.8: Distribution return on capital allowance, $ million nominal

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening RAB	5,834.9	6,180.5	6,529.0	6,911.4	7,166.7
Post-tax nominal WACC	6.09%	6.09%	6.09%	6.09%	6.09%
Indicative return on capital	355.3	376.3	397.6	420.8	436.4

10.8.1 Removing the double count of inflation

902. The main change from moving to post-tax nominal modelling is the calculation of the rate of return building block. Under the new method the RAB is rolled forward in real terms, then converted to nominal dollars to derive the return on assets and depreciation building blocks. When determining the return on assets, the calculation applies a nominal WACC on a nominal RAB. This effectively applies inflation twice on the RAB. To offset this, the approach generally used is to deduct an amount representing the inflationary gain on the RAB from the building blocks. These amounts are shown below.

Table 10.9: Inflation deductions for distribution and transmission, $ million nominal

	2017/18	2018/19	2019/20	2020/21	2021/22
Transmission	51.4	53.1	55.5	58.5	60.8
Distribution	95.7	101.4	107.1	113.3	117.5

10.9 Return of capital (depreciation)

903. Depreciation is an allowance provided to Western Power so capital investors recover the cost of their investment over the economic life of the asset. RAB depreciation is modelled in two parts:

1. **initial capital base** - depreciating the opening capital base when Western Power was first disaggregated in 2006
2. **new capital expenditure** - depreciating the capital expenditure incurred each year in the access periods following disaggregation.

904. In order to depreciate new capital expenditure it must be allocated into asset categories with matching asset lives. Western Power allocates transmission and distribution capital expenditure to regulatory asset categories as follows:

- Western Power reports capital expenditure for both transmission and distribution under the following broad activity categories:
  - growth (capacity expansion, customer driven, gifted assets)
  - asset replacement and renewal (asset replacement, State Undergrounding Power Program (SUPP), metering, wood pole management)
  - improvement in service (reliability driven, SCADA and communications
  - compliance (safety, environment and statutory)
  - corporate (ICT and business support).
- The activity categories are allocated to the following transmission regulatory asset categories:
  - cables
  - Transmission steel towers
  - wooden poles
  - metering
  - transformers
  - reactors
  - capacitors
  - circuit breakers
  - SCADA and communications
  - IT
  - other non-network
  - land and easements.
- The activity categories are allocated to the following distribution regulatory asset categories:
  - wooden pole lines
  - underground cables
  - transformers
  - switchgear
  - street lighting
  - meters services
  - SCADA and communications
  - ICT
  - Other non-network
  - land and easements.

905. Annual capital expenditure in each of these distribution regulatory asset categories is depreciated over its approved standard life on a real straight line basis. We propose to maintain this depreciation methodology for all investments in the AA4 period.

906. Each asset category also has an opening value and remaining life assigned for the initial capital base. Depreciation on these values is also done on a straight line basis for the number of years specified (counting from 2006).

907. Table 10.10 shows the forecast AA4 depreciation for distribution and transmission. More detail on the depreciation calculation can be found in Attachment 10.2.

Table 10.10: Forecast depreciation, $ million nominal

	2017/18	2018/19	2019/20	2020/21	2021/22
Transmission	115.5	121.1	133.2	147.5	156.5
Distribution	267.9	290.1	309.9	318.3	313.6

10.9.1 Economic life

908. We propose the same economic lives that were applied in the AA3 period for the majority of the asset groups. The exception is distribution meters and services where the economic life is proposed to be 15 years (previously 25 years). This change will only affect the calculation of the depreciation for new facilities investment undertaken during the AA4 period. New facilities investment undertaken in previous access arrangements will continue to be depreciated based on the economic lives that applied at the time the depreciation forecast was developed for the investment.

909. Table 10.11 and Table 10.12 show the economic lives for transmission and distribution assets proposed for the AA4 period.

Table 10.11: AA4 transmission asset economic lives

	Economic life
Cables	55.0
Steel towers	60.0
Wooden poles	45.0
Metering	40.0
Transformers	50.0
Reactors	50.0
Capacitors	40.0
Circuit breakers	50.0
SCADA and communications	11.0
ICT	6.0

	Economic life
Other non-network assets	16.9
Land and easements	0.0
Equity raising costs	49.0

Table 10.12: AA4 distribution asset economic lives

	Economic life
Wood pole lines	41.0
Underground cables	60.0
Transformers	35.0
Switchgear	35.0
Street lighting	20.0
Meters and services	15.0
ICT	6.0
SCADA and communications	10.2
Other distribution non-network	10.2
Distribution land and easements	0.0
Equity raising costs	43.0

10.10 Return on working capital

910. Working capital refers to a stock of funds that Western Power must maintain to pay costs as they fall due. 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. 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.

911. For the AA3 period, the ERA agreed a return on an amount of capital investment was needed to provide for working capital, and was an efficient cost of providing covered services. We propose to continue using the same method and assumptions for determining the cost of working capital as previously approved. 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 – 4.0%
- accounts payable – 45 days

- accounts receivable – 24.2 days .

912. Return on working capital has been included in target revenue for AA4. Working capital requirements over AA4 are shown in Table 10.13.

Table 10.13: Forecast working capital, $ million nominal

	2017/18	2018/19	2019/20	2020/21	2021/22
Transmission	25.4	28.2	31.0	35.6	39.7
Distribution	117.2	124.0	127.0	133.8	137.2

10.11 Forecast operating expenditure

913. Western Power is proposing to spend $1,805 million of operating expenditure in the AA4 period. Under the building blocks method, this expenditure is added to target revenue in the year it is forecast to be incurred. Chapter 7 provides a detailed explanation of how the forecast was derived.

10.12 Revenue adjustments under AA3 adjustment mechanisms

914. Western Power will recover $517 million positive adjustment in AA4 as a result of various revenue adjustment mechanisms in place during AA3.

915. The AA3 adjustment mechanisms result in a $556 million positive adjustment to reflect service performance, efficiency rewards, demand management services and unforeseen events. This is offset by a $39.5 million negative adjustment for variance to forecast growth-related expenditure.

916. Table 10.14 summarises the financial implications of the adjustment mechanisms on the AA4 target revenue.

Table 10.14: Revenue adjustments under AA3 adjustment mechanisms

Adjustment mechanism	Present value adjustment to AA4 transmission revenue	Present value adjustment to AA4 distribution revenue
Investment adjustment mechanism (**IAM**)	-33.6	-5.9
Gain sharing mechanism (**GSM**)	103.7	168.9
Service standard adjustment mechanism (**SSAM**)	13.4	241.7
D-factor	0.0	8.8
Unforeseen events	5.5	14.2
Technical Rules changes	0.0	0.0
Total	89.0	427.7

917. The following sections describe the revenue adjustments under each AA4 mechanism.

10.12.1 IAM

918. We have subtracted $39.5 million from AA4 target revenue in line with the requirements of the IAM. This amount has been calculated in accordance with section 7.3 of the current access arrangement.

919. The IAM 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 capex in certain AA3 expenditure categories. The AA3 capex categories were:

- growth-related capital
- the State Underground Power Program (**SUPP**)
- the Rural Power Improvement Program (**RPIP**)
- distribution wood pole investment.

920. The IAM is calculated by comparing the forecast capex with the actual capex incurred 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 capital expenditure in the IAM expenditure categories. The revenue adjustment is the difference between the building blocks adjusted for the time value of money and inflation.

10.12.1.1 IAM adjustments for growth-related transmission capex

921. Western Power will return $33.6 million to customers due to differences between actual and forecast growth-related capex on the transmission network during AA3. Table 10.15 shows the transmission revenue adjustment.

Table 10.15: Transmission revenue adjustment due to the IAM, $ million real at 30 June 2017

	2012/13	2013/14	2014/15	2015/16	2016/17
Forecast IAM transmission capex (net of capital contributions)					
Total IAM transmission capex	225.0	320.8	165.5	176.4	266.5
Revenue – return on and return of	0.0	11.4	27.4	35.5	44.1
Actual IAM transmission capex (net of capital contributions)					
Total IAM transmission capex	143.7	256.1	67.6	27.5	22.4
Revenue – return on and return of	0.0	8.4	22.2	26.7	29.9
Revenue adjustment under IAM	**0.0**	**-2.9**	**-5.3**	**-8.8**	**-14.2**

10.12.1.2 IAM adjustments for distribution capex (including SUPP, RPIP, and wood poles)

922. Western Power will return $5.9 million to customers due to differences between actual and forecast distribution capex, on growth related projects, the State Underground Power Program (**SUPP**), and wood pole investment. There was no Rural Power Improvement Program (**RPIP**) expenditure during AA3.

923. Table 10.16 shows the distribution revenue adjustment.

Table 10.16: Distribution revenue adjustment due to the IAM, $ million real at 30 June 2017

	2012/13	2013/14	2014/15	2015/16	2016/17
Forecast IAM distribution capex (net of capital contributions)					
Total IAM transmission capex	396.8	422.3	438.7	450.2	475.7
Revenue – return on and return of	0.0	23.9	49.1	74.8	100.8
Actual IAM distribution capex (net of capital contributions)					
Total IAM transmission capex	424.1	439.2	362.7	281.0	168.5
Revenue – return on and return of	0.0	24.9	50.6	73.6	93.6
Revenue adjustment under IAM	**0.0**	**1.0**	**1.6**	**-1.1**	**-7.2**

10.12.2 GSM

924. $272.6 million is included in AA4 target revenue as a result of performance under the GSM during the AA3 period. The GSM provides Western Power an incentive to make operating cost efficiencies by allowing the business to add a share of efficiency gains achieved during one access arrangement period to target revenue for the next access arrangement period. Efficiency improvements must not be made at the expense of service performance, therefore GSM rewards are only applied if Western Power achieves a defined set of minimum service standards. Customers receive the majority of the benefits as a result of the significantly lower opex in future periods.

925. We have applied the GSM in accordance with section 7.4 of the current access arrangement. The current GSM requires Western Power to achieve all 17 SSBs in any one year in order to receive efficiency rewards. The business met all 17 SSBs in two of the five years of the AA3 period.

926. The formulation detailed in section 7.4 is summarised in the following tables. The values for EIB_t and A_t for each year have been updated for actual audited scale escalation factors. We engaged Deloitte to perform an audit of the efficiency and innovation scale escalation factors for the AA3 period (see Attachment 10.3).

927. Deloitte found:

> *In our opinion, based on the procedures performed, in all material respects:*
>
> - *The data used in the calculation of the scale escalation drivers for the purposes of AA3 section 7.4.8(b)(i) for the 2011/12 to 2016/17 financial years is valid and has been accurately and completely applied*
> - *The scale escalation drivers are calculated in accordance with the methodology set out in table 34 of AA3.*

928. A detailed calculation is shown in the revenue model (Confidential Attachment 10.4). The current access arrangement specifies the GSM reward as a whole of Western Power reward without specifying how this should be allocated between distribution and transmission. The revenue model calculates a notional GSM reward for distribution and transmission separately, and uses these outcomes to allocate the total reward to transmission and distribution.

Table 10.17: Calculation of inputs for GSM calculation, $ million real at 30 June 2017

	2012/13	2013/14	2014/15	2015/16	2016/17
Efficiency and innovation benchmark - EIBt	486.9	489.2	481.7	473.0	481.4
A_t (actual non-capital costs)	489.5	485.6	457.9	482.6	420.3
Above Benchmark Surplus (ABS_t) (EIB_t less A_t)	-2.6	6.2	20.2	-33.5	70.8
ABS_t adjusted for service standard performance	**-2.6**	**0.0**	**20.2**	**-33.5**	**70.8**

Table 10.18: Calculation of GSM outcomes, $ million real at 30 June 2017

	2012/13	2013/14	2014/15	2015/16	2016/17
Total - $GSMA_t$	54.9	57.5	57.5	37.3	70.8
Distribution allocation	36.4	37.5	34.8	13.3	46.9
Transmission allocation	18.5	20.0	22.7	24.0	23.9

10.12.3 SSAM

929. $255.1 million is included in AA4 target revenue as a result of performance under the SSAM. This amount has been calculated in accordance with section 7.5 of the access arrangement.

930. The SSAM provides an incentive to maintain and/or improve service above the service standard benchmarks for the AA3 period by providing financial rewards for performance improvements. 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. Service performance over the AA3 period is detailed in Chapter 5.

10.12.3.1 Adjustment against transmission service standard targets

931. Western Power has incurred an overall $13.4 million reward under the SSAM for performance against the transmission network service standard targets during the AA3 period. Table 10.19 shows performance compared with the service standard target and the associated financial penalty or reward for each measure.

Table 10.19: AA3 transmission SSAM adjustments, $ million real at 30 June 2017

	2012/13	2013/14	2014/15	2015/16	2016/17
Circuit availability (% of total time)					
Target	98.1	98.1	98.1	98.1	98.1
Performance	98.4	98.0	98.5	98.7	98.9

	2012/13	2013/14	2014/15	2015/16	2016/17
Penalty / reward	**2.7**	**-0.5**	**3.6**	**5.4**	**7.2**
System minute interrupted radial (minutes)					
Target	1.9	1.9	1.9	1.9	1.9
Performance	1.2	3.7	1.6	0.5	0.7
Penalty / reward	**0.1**	**-0.3**	**0.0**	**0.2**	**0.1**

10.12.3.2 Adjustment against distribution service standard targets

932. Western Power has incurred an overall $241.7 million reward under the SSAM for performance against the distribution network service standard targets during the AA3 period. Table 10.20 shows performance compared with the service standard target and the associated financial penalty or reward for each measure.

Table 10.20: AA3 distribution SSAM adjustments, $ million real at 30 June 2017

	2012/13	2013/14	2014/15	2015/16	2016/17
SAIDI - CBD (minutes)					
Target	20.3	20.3	20.3	20.3	20.3
Performance	7.6	18.3	26.2	22.6	13.8
Penalty / reward	**0.9**	**0.1**	**-0.4**	**-0.2**	**0.5**
SAIDI - Urban (minutes)					
Target	136.6	136.6	136.6	136.6	136.6
Performance	102.7	107.4	103.0	91.3	104.4
Penalty / reward	**19.8**	**17.1**	**19.6**	**26.5**	**18.8**
SAIDI – Rural short (minutes)					
Target	207.8	207.8	207.8	207.8	207.8
Performance	181.4	171.2	182.6	168.4	175.6
Penalty / reward	**6.5**	**9.0**	**6.2**	**9.7**	**7.9**
SAIDI - Rural long (minutes)					
Target	582.2	582.2	582.2	582.2	582.2
Performance	685.4	673.8	677.5	582.6	626.2
Penalty / reward	**-7.4**	**-6.6**	**-6.9**	**0.0**	**-3.2**

	2012/13	2013/14	2014/15	2015/16	2016/17
SAIFI – CBD (number of instances)					
Target	0.14	0.14	0.14	0.14	0.14
Performance	0.03	0.20	0.17	0.10	0.11
Penalty / reward	**1.1**	**-0.6**	**-0.3**	**0.4**	**0.3**
SAIFI – Urban (number of instances)					
Target	1.36	1.36	1.36	1.36	1.36
Performance	1.16	1.13	1.09	0.91	1.00
Penalty / reward	**12.1**	**13.9**	**16.3**	**27.2**	**20.6**
SAIFI – Rural short (number of instances)					
Target	2.27	2.27	2.27	2.27	2.27
Performance	2.17	1.83	1.98	1.75	1.76
Penalty / reward	**2.5**	**10.8**	**7.1**	**12.8**	**12.5**
SAIFI – Rural long (number of instances)					
Target	4.06	4.06	4.06	4.06	4.06
Performance	4.91	4.98	4.41	3.99	3.95
Penalty / reward	**-5.0**	**-5.0**	**-3.9**	**0.8**	**1.2**

10.12.3.3 Adjustment against call centre SSAM targets

933. Western Power has incurred an overall $9.2 million reward under the SSAM for performance against the call centre performance service standard targets during the AA3 period. Table 10.21 shows performance compared with the service standard target and the associated financial penalty or reward for the measure.

Table 10.21: AA3 call centre performance SSAM adjustments. $ million real at 30 June 2017

	2012/13	2013/14	2014/15	2015/16	2016/17
Call centre performance (% calls responded to within 30 seconds)					
Target	87.6	87.6	87.6	87.6	87.6
Performance	90.6	92.8	93.7	91.4	91.8
Penalty / reward	**1.4**	**2.4**	**2.8**	**1.7**	**1.9**

10.12.4 D-factor

934. Western Power seeks an adjustment to AA4 target revenue of $8.8 million. This is to recover the costs associated with the Ravensthorpe and Bremer Bay network control services (**NCS**). Section 7.6 of the current access arrangement permits Western Power, in certain circumstances, to recover non-capital costs through the D-factor scheme.

935. NCS enable Western Power to procure generation and demand management in localised areas of network constraint to defer the need for more costly network augmentation. The Ravensthorpe Power Station has been providing NCS since 2012/13, while Bremer Bay has been in operation since 2006. In both cases, localised generation can be dispatched in response to network contingencies at peak times and during lengthy outages to ensure covered services can be provided and reliability is not compromised.

936. In accordance with the requirements of the access arrangement, the opex associated with these network control services relates to demand management or a generation solution that would otherwise require network augmentation. We consider this opex is compliant with the requirements of Sections 6.40 and 6.41 of the Access Code. Further information on both of the network control services is provided within the compliance summaries in Confidential Attachments 10.5 and 10.6.

Table 10.22: AA4 D-factor revenue adjustment, $ million real at 30 June 2017

	2012/13	2013/14	2014/15	2015/16	2016/17
Ravensthorpe	1.2	0.8	0.6	0.6	0.6
Bremer Bay	0.9	1.0	1.1	0.9	0.1
Total	2.1	1.8	1.7	1.5	0.6

10.12.5 Unforeseen events

937. Section 6.6 of the Access Code, and section 7.1 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. Western Power seeks an adjustment to AA4 target revenue to recover the efficient and unrecovered costs associated with the State Government's Electricity Market Review.

938. Section 6.6 of the Access Code provides that target revenue may be adjusted for unforeseen events:

> *6.6 If:*
>
> *(a) during the previous access arrangement period, a service provider incurred capital-related costs or non-capital costs as a result of a force majeure event; and*
>
> *(b) the service provider was unable to, or is unlikely to be able to, recover some or all of the costs ("unrecovered costs") under its insurance policies; and*
>
> *(c) at the time of the force majeure event the service provider had insurance to the standard of a reasonable and prudent person (as to the insurers and the type and level of insurance),*
>
> *then subject to section 6.8 an amount may be added to the target revenue for the covered network for the next access arrangement period in respect of the unrecovered costs.*

6.7 Nothing in section 6.6 requires the amount added under section 6.6 in respect of unrecovered costs to be equal to the amount of unrecovered costs.

6.8 An amount must not be added under section 6.6 in respect of capital-related costs or non-capital costs, to the extent that they exceed the costs which would have been incurred by a service provider efficiently minimising costs.

939. A force majeure event is defined in the Access Code as follows:

"force majeure" in respect of a party means an event or circumstance beyond the party's control, and which the party acting as a reasonable and prudent person is not able to prevent or overcome, including (where the foregoing conditions are satisfied):

…

(d) any act or omission of government or any government or regulatory department, body, instrumentality, ministry, agency, fire brigade; or

…

940. We submit that the Electricity Market Review (**EMR**) is classified under the Access Code as a force majeure event. As discussed in Chapter 3, the EMR was a State Government-led initiative that proposed a series of reforms to the Western Australian energy sector. The EMR had two phases, the first of which was largely investigatory and resulted in Western Power incurring some discretionary costs. The second phase laid out specific market reform, which imposed significant mandatory costs on Western Power.

941. The need to incur EMR costs was outside Western Power's control. The EMR was not foreseen at the beginning of the AA3 period, therefore no forecast costs were included in the AA3 access arrangement decision. These costs are not recoverable under Western Power's insurance policies.

942. We have reviewed all costs incurred due to the EMR and have applied the following approach with regards to the force majeure cost classification:

- costs incurred in EMR Phase 1 are considered discretionary as there was no fixed reform agenda at that time – these costs ***have not been included*** in the force majeure event
- some of the costs incurred in EMR Phase 2 may have been incurred even without the introduction of the review – these costs ***have not been included*** in the force majeure event.
- the remainder of the costs incurred in Phase 2 are considered directly related to the introduction of the review – these costs ***have been included*** in the force majeure event.

943. The following accounting treatment has been applied to EMR costs that have been included in the force majeure event:

- costs that were incurred of a capital nature were capitalised (e.g. IT costs)
- costs that had potential to provide a benefit to Western Power should it transition to the National Electricity Rules in the future were capitalised
- all remaining costs were expensed (i.e. operating expenditure).

944. Table 10.23 and Table 10.24 summarise the EMR opex and capex that Western Power will include as a force majeure event in the AA4 proposal. The tables also show the opex and capex amounts associated with the force majeure event. The revenue adjustment due to the opex amounts is $19.7 million (in present value terms).

945. For the avoidance of doubt, Western Power is not proposing to recover any additional revenue associated with the capex amounts, the amounts will be added to the RAB like other capex in AA3. The amounts are shown here for completeness.

Table 10.23: Summary of EMR opex incurred, $ million real at 30 June 2017

	Total cost incurred	Less excluded costs	Total force majeure
Network regulation – regulatory submission program	8.8	-2.6	6.2
Market competition – contestability	1.4	-	1.4
Market competition – connections and access	2.0	-	2.0
Institutional arrangements – System Management /AEMO	4.6		4.6
Review program management – EMR transition	4.3		4.3
Total	**21.3**	**-2.6**	**18.7**

Table 10.24: Summary of EMR capex incurred, $ million real at 30 June 2017

	Total cost incurred	Excluded costs	Total force majeure
Network regulation – regulatory submission program	5.6	-0.06	5.6
Institutional arrangements – System Management /AEMO	0.5		0.5
Review program management – EMR transition	0.3		0.3
Total	**6.4**	**-0.06**	**6.4**

10.12.6 Technical Rules changes

946. Western Power has assessed the Technical Rules changes that occurred over AA3 and determined there is no need for an adjustment to target revenue for AA4. This assessment is provided in Attachment 10.7.

10.13 Tariff equalisation contribution

947. $822 million ($ nominal) is included in AA4 target revenue for the 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.

948. The purpose of the TEC is to enable the regulated retail tariffs for electricity that is not supplied from the 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 enables the TEC to be recovered from users of the distribution network.

949. As per the AA3 period we propose to recover the TEC from distribution customers with demand less than 7,000 kVA. Customers with demand greater than 7,000 kVA do not pay the TEC as these customers can

usually choose between being connected to the transmission or the distribution network. Charging the 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.

950. The State Government periodically gazettes the TEC amounts. Given the potential changes that may occur to the TEC over the AA4 period, the price control formula for the distribution system includes an explicit pass-through element for the TEC.

951. The forecast TEC over the AA4 period aligns with the TEC forecast in the State Budget, and is shown in Table 10.25. At the time of this submission the TEC requirement for the entire AA4 period has not been gazetted by the Government.

Table 10.25: Forecast TEC for the AA4 period, $ nominal

	2017/18	2018/19	2019/20	2020/21	2021/22
Tariff equalisation contribution	167.0	175.0	162.0	157.0	161.0

10.14 Deferred revenue

952. As part of the ERA's access arrangement decision for the AA2 period, revenue amounts were deferred to future access arrangement periods for both distribution and transmission.[190] These deferred revenue amounts are to be recovered over the average life of assets on each system – that is, 42 years for distribution and 50 years for transmission – as a real annuity.

953. The roll forward of these amounts from the opening of the AA3 period to the closing of the AA4 period is shown in the tables below, along with the revenue being recovered in the AA4 period.

Table 10.26: Transmission deferred revenue roll forward over the AA3 period, $ real at 30 June 2017

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening deferred revenue value	96.7	95.9	95.2	94.4	93.6
less principal recovered	0.7	0.7	0.8	0.8	0.8
Closing deferred revenue value	**95.9**	**95.2**	**94.4**	**93.6**	**92.8**

190 In the AA2 period, transmission prices increased by 13 per cent per annum, and distribution prices increased by 18 per cent per annum. It was primarily driven by a change in capital contributions, which if allowed in full would have resulted in price increases of over 30 per cent per annum. To minimise this price shock, $823 million of revenue was deferred from AA2 to future periods.

Table 10.27: Transmission deferred revenue roll forward over the AA4 period, $ real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening deferred revenue value	92.8	92.1	91.4	90.6	89.9
less principal recovered	0.7	0.7	0.8	0.8	0.8
Closing deferred revenue value	**92.1**	**91.4**	**90.6**	**89.9**	**89.0**
Revenue recovered through tariffs	4.8	4.8	4.8	4.8	4.8

Table 10.28: Distribution deferred revenue roll forward over the AA3 period, $ real at 30 June 2017

	2012/13	2013/14	2014/15	2015/16	2016/17
Opening deferred revenue value	726.1	718.5	710.6	702.3	693.9
less principal recovered	7.6	7.9	8.2	8.5	8.8
Closing deferred revenue value	**718.5**	**710.6**	**702.3**	**693.9**	**685.0**

Table 10.29: Distribution deferred revenue roll forward over the AA4 period, $ real at 30 June 2017

	2017/18	2018/19	2019/20	2020/21	2021/22
Opening deferred revenue value	685.0	677.3	669.3	660.8	652.0
less principal recovered	7.7	8.1	8.4	8.8	9.2
Closing deferred revenue value	677.3	669.3	660.8	652.0	642.9
Revenue recovered through tariffs	**37.7**	**37.7**	**37.7**	**37.7**	**37.7**

10.14.1 Deferred revenue due to transmission revenue recovery issues

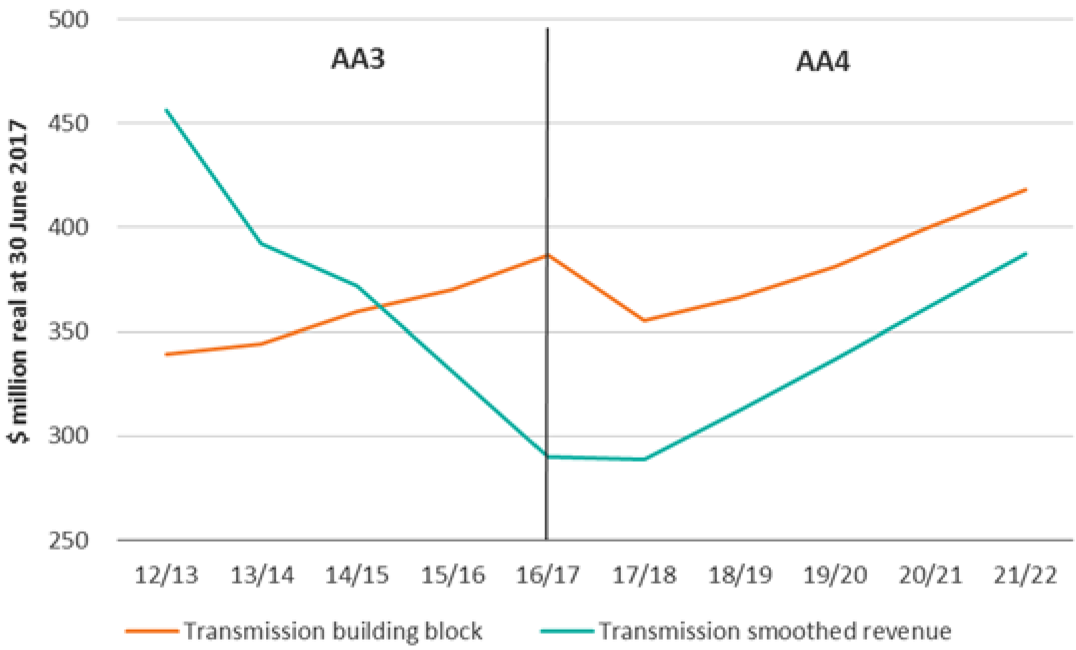
954. Transmission revenue over the AA3 period was materially lower (on a per annum basis) than during the AA2 period. This was largely the result of a significant reduction in the WACC between periods. The WACC in the AA2 period was 7.98 per cent real pre-tax, falling to 4.33 per cent real pre-tax for the AA3 period.

955. Prices are set to recover the target revenue as calculated by the revenue building blocks. However, because the timing of expenditure typically varies during the course of an access arrangement period, the amount of building block revenue required each year can vary.

956. To minimise price volatility between years, it is normal practice to smooth the recovery of revenue over an access arrangement period to minimise variances in revenue to be collected each year. The ERA applied a smooth price path to Western Power's revenue during the AA3 period.

957. Because AA3 transmission revenue was so much lower than AA2 transmission revenue, the smoothed transmission price path has declined over the AA3 period. The smoothed path started with prices higher than building block revenue at the beginning of the AA3 period, and falling below building block revenue by the end of the AA3 period (see Figure 10.4).

Figure 10.4: Transmission revenue path over the AA2, AA3 and AA4 periods



958. The result of this smoothing effect is that the transmission revenue path (the orange line in Figure 10.4) is substantially lower than the building block revenue (the blue line) at the end of the AA3 period. This also means transmission prices are significantly lower at the end of the AA3 period. This causes the potential for price shock in the AA4 period.

959. Even though the transmission target revenue for the AA4 period is a similar level to that of the AA3 period, the prices at the end of AA3 are so far below the revenue building blocks that there must be a sharp price increase (even with a smooth price path) over the AA4 period in order to recover the transmission target revenue. The increase is exacerbated by the fact that the AA4 network tariffs are unlikely to come into effect until 1 July 2018, one year after the initial revisions commencement date for the AA4 period[191], which means the AA4 transmission target revenue will be recovered over four years rather than five.

960. If Western Power collects all forecast transmission target revenue over the AA4 period, transmission network prices would have to increase by 18 per cent per annum. We recognise that price increases of this magnitude would result in price shock for transmission customers, and have looked at a range of solutions

191 The AA4 period was due to commence on 1 July 2017, however, a series of Government-led energy market reforms (and their subsequent suspension) meant the lodgement date for Western Power's AA4 proposal was moved to 2 October 2017. The revised access arrangement will not be in place until the ERA makes its AA4 Further Final Decision, expected June 2018.

to reduce the size of the transmission tariff increases. The options considered are discussed in Attachment 10.8.

961. Our solution to mitigate the price increase on transmission customers is to defer the recovery of $234.1 million of AA4 transmission target revenue to future access arrangement periods, and bring forward the recovery of the same amount of previously deferred distribution revenue to the AA4 period. Put simply, we are substituting the collection of $234.1 million transmission revenue during AA4 for $234.1 million of distribution revenue instead.

962. The deferral amount is such that it caps the transmission price increase for the AA4 period to 10 per cent per annum. This is significantly less than the 18 per cent that would apply otherwise.

963. The increase in distribution revenue does not materially impact network tariffs for distribution customers. This is because the distribution customer base (more than one million customers) is significantly larger than the transmission customer base, therefore the costs are spread over a much larger number of connection points.

964. Western Power remains revenue neutral as a result of this switch between distribution and transmission revenue. It is also worth noting that distribution customers are not paying any more or transmission customers paying any less over the longer terms as a result of this treatment of deferred revenue. In effect, all that is changing is the timing of when customers will be required to pay for transmission and distribution covered services.

965. During our customer engagement program, customers made it clear that they were sensitive to price increases.[192] We submit this transmission/distribution deferred revenue switch is a reasonable solution to help manage price shock for transmission customers while not materially impacting distribution customers.

966. Table 10.30 and Table 10.31 shows the transmission and distribution deferred revenue roll forward amounts for the AA4 period, including the effect of this additional deferred revenue switch.

Table 10.30: Transmission deferred revenue roll forward, $ real at 30 June 2017

Transmission revenue	2017/18	2018/19	2019/20	2020/21	2021/22
Opening deferred revenue value	92.8	158.5	212.2	255.9	293.5
less principal recovered	0.7	0.7	0.8	0.8	0.8
plus additional deferral	66.4	54.4	44.5	38.4	30.4
Closing deferred revenue value	**158.5**	**212.2**	**255.9**	**293.5**	**323.1**

192 Customer insight #1, *Western Power customer insights feedback report*, Deloitte, August 2016.

Table 10.31: Distribution deferred revenue roll forward, $ real at 30 June 2017

Distribution revenue	2017/18	2018/19	2019/20	2020/21	2021/22
Opening deferred revenue value	685.0	610.9	548.5	495.6	448.4
less principal recovered	7.7	8.1	8.4	8.8	9.2
less brought forward recovery	66.4	54.4	44.5	38.4	30.4
Closing deferred revenue value	**610.9**	**548.5**	**495.6**	**448.4**	**408.8**

10.15 Tax

967. Western Power's revenue requirement for the AA4 period includes an allowance for expected corporate income tax. A notional whole of business AA4 tax expense is calculated taking into consideration forecast revenue, operating expenditure, interest on debt, tax depreciation and TEC allowances.

968. In order to allocate the expected corporate income tax between the transmission and distribution portions of the business, notional calculations are carried out separately for distribution and transmission. The whole of business tax expense is allocated on the basis of the proportion of the notional profit and loss for each business segment.

969. To estimate the cost of corporate income tax, we have used the current corporate tax rate of 30 per cent, and a value for imputation credits (gamma) of 0.40. Table 10.32, Table 10.33 and Table 10.34 show the whole of business income tax expense and the allocation between transmission and distribution respectively.

Table 10.32: Estimated cost of corporate income tax for the AA4 period, $ nominal

	2017/18	2018/19	2019/20	2020/21	2021/22
Western Power - Taxable income	271.9	323.3	354.9	344.1	387.5
Estimated cost of corporate income tax	81.6	97.0	106.5	103.2	116.2
Less value of imputation credits	-32.6	-38.8	-42.6	-41.3	-46.5

Table 10.33: Corporate income tax allocation to transmission cost of services for the AA4 period, $ nominal

	2017/18	2018/19	2019/20	2020/21	2021/22
Tax payable	0.0	0.0	0.0	0.0	15.0
Less value of imputation credits	0.0	0.0	0.0	0.0	-6.0

Table 10.34: Corporate income tax allocation to distribution cost of services for the AA4 period, $ nominal

$M	2017/18	2018/19	2019/20	2020/21	2021/22
Tax payable	81.6	97.0	106.5	103.2	101.3
Less value of imputation credits	-32.6	-38.8	-42.6	-41.3	-40.5

10.16 K-factor adjustment for 2017/18

970. Due to the one year delay in commencement of the AA4 revenue recovery, the revenue caps for 2017/18 are treated slightly differently. In the normal course of events, there would be a revised Price List and Price List Information produced for 2017/18, and these documents would outline the calculation of the revenue target for the year (using the formulae in the next section), including a calculation of the revenue adjustment factor (known as the k-factor). The versions of these documents (Appendix F.1 and F.2 to the proposed access arrangement) are the 2016/17 Price List reproduced, without any adjustments made for the k-factor. The 2016/17 Price List is adopted as the 2017/18 Price List absent a different Price List produced in April 2017 and approved by the ERA in May 2017 due to the delay to the AA4 process.

971. The k-factor adjustment takes into account the actual and forecast revenues recovered in previous financial years and adjusts the revenue target to ensure Western Power is recovering the required revenue amounts exactly. That is, if previous year's prices had over-recovered revenue then that over-recovery would be given back to customers through a lower revenue requirement in the next year, vice versa for under-recoveries.

972. To ensure the addition of this revenue adjustment doesn't result in lumpy price outcomes, the revenue model has been run with the k-factor for 2017/18 included as a building block. The revenue model also specifies revenue amounts for 2017/18 that reflect the most recently available revenue forecasts for the year, given that the 2016/17 will likely apply for the whole year. As the AA4 decision process continues, these numbers will be updated with more up-to-date forecasts.

10.17 Target revenue and revenue caps

973. Western Power's target revenue for the AA4 period, split by transmission and distribution, is set out in Table 10.35 and Table 10.36.

Table 10.35: AA4 transmission target revenue, $ million nominal

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Operating expenditure	95.4	87.0	87.3	90.2	91.7	451.6
Depreciation	64.2	68.0	77.7	89.1	95.7	394.6
Redundant assets/Accelerated depreciation	-	-	-	-	-	-
Deferred revenue recovery	4.8	4.9	5.0	5.1	5.2	25.0
Tax payable	-	-	-	-	15.0	15.0
Less value of imputation credits	-	-	-	-	-6.0	-6.0

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Return on assets	190.7	197.1	206.2	217.1	225.7	1,036.8
Return on working capital	1.1	1.5	1.7	1.9	2.2	8.4
IAM revenue adjustment	-34.1	-	-	-	-	-34.1
SSAM revenue adjustment	13.6	-	-	-	-	13.6
Unforeseen events revenue adjustment	5.6	-	-	-	-	5.6
Technical rule change revenue adjustment	-	-	-	-	-	-
D-factor revenue adjustment	-	-	-	-	-	-
GSM revenue adjustment	18.5	20.0	22.7	24.0	23.9	109.1
K-factor adjustment	1.3	-	-	-	-	1.3
Transmission target revenue for revenue cap services (unsmoothed)	**361.1**	**378.5**	**400.5**	**427.4**	**453.4**	**2,020.9**

Table 10.36: AA4 distribution target revenue, $ million nominal

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Operating expenditure	297.3	277.2	279.9	291.0	298.1	1,443.4
Depreciation	172.3	188.8	202.9	205.0	196.1	964.9
Redundant assets/accelerated Depreciation	-	-	-	-	-	-
Deferred revenue recovery	105.8	95.1	86.3	81.2	73.9	442.4
Tax payable	81.6	97.0	106.5	103.2	101.3	489.5
Less value of imputation credits	-32.6	-38.8	-42.6	-41.3	-40.5	-195.8
Tariff equalisation	167.0	175.0	162.0	157.0	161.0	822.0
Return on assets	355.3	376.3	397.6	420.8	436.4	1,986.5
Return on working capital	7.2	7.1	7.5	7.7	8.1	37.8
IAM revenue adjustment	-6.0	-	-	-	-	-6.0
SSAM revenue adjustment	245.7	-	-	-	-	245.7
Unforeseen events revenue adjustment	14.4	-	-	-	-	14.4

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Technical rule change revenue adjustment	-	-	-	-	-	-
D-factor revenue adjustment	8.9	-	-	-	-	8.9
GSM revenue adjustment	37.0	38.7	36.6	14.2	50.9	177.4
K-factor adjustment	37.2	-	-	-	-	37.2
Distribution target revenue for revenue cap services (unsmoothed)	**1,491.2**	**1,216.5**	**1,236.6**	**1,238.9**	**1,285.2**	**6,468.3**

10.17.1 Annual revenue cap

974. The revenue to be recovered under the revenue cap for each year of the AA4 period reflects the target revenue and the price control formula. The proposed access arrangement specifies formulae that outline how the actual revenue allowances in each year of the AA4 period are built up based on the revenue caps initially determined in the revenue model.

975. These formulae take the base revenue cap number and add on various adjustments required for each year. The first addition is known as the k-factor and this ensures that the revenue allowances each year fully recover the revenue caps in place for the period. This is effectively a true up mechanism.

976. The second addition is for the TEC, which is added on to the base distribution revenue cap amount.

977. The third (the $AA3_t$ term) is there to ensure that if an error is made in the calculations of revenue adjustments from the AA3 adjustment mechanism, that this error can be corrected in AA4. It is expected that this term will be zero throughout AA4.

978. The price control formula for the **transmission** system is:

$$MTR_t = TR_t + AA3_t + TK_t$$

where:

- MTR_t is the maximum transmission revenue cap services revenue for each year, t, of AA4
- TR_t is the annual transmission revenue cap services revenue in year t
- $AA3_t$ is a positive or negative amount for the financial year t calculated to correct for any errors in the amounts included in the calculation of TRt to give effect to revenue adjustments (if applicable) arising from the operation of the previous access arrangement
- TK_t is the transmssion revenue correction factor for differences in revenue collected by us and the revenue cap.

979. Table 10.37 shows the TR_t annual parameters for the AA4 period.

Table 10.37: Transmission smoothed annual revenue, $ million real at 30 June 2017

Transmission revenue	2017/18	2018/19	2019/20	2020/21	2021/22
Annual revenue cap services revenue	288.8	312.0	337.0	362.1	387.5
Less TK_t	1.2				
Annual revenue cap services revenue – TR_t	287.6	312.0	337.0	362.1	387.5
% change in TR_t		-8.5%	-8.0%	-7.5%	-7.0%

980. The price control formula for the **distribution** system is:

$$MDR_t = DR_t + AA3_t + TEC_t + DK_t$$

where:

- MDR_t is the maximum distribution revenue cap services revenue for each year, t, of AA4
- DR_t is the annual distribution revenue cap services revenue in year t
- $AA3_t$ is a positive or negative amount for the financial year t calculated to correct for any errors in the amounts included in the calculation of DRt to give effect to revenue adjustments (if applicable) arising from the operation of the previous access arrangement
- TEC_t 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
- DK_t the distribution revenue correction factor for differences in revenue collected by us and the revenue cap.

981. We have calculated the DR_t parameter by using the forecasts for TEC_t shown in section 10.13.

982. Table 10.38 shows the DRt annual parameters for the AA4 period.

Table 10.38: Distribution smoothed annual revenue, $ million nominal

Distribution revenue	2017/18	2018/19	2019/20	2020/21	2021/22
Annual revenue cap services revenue	1,221.2	1,228.9	1,246.1	1,256.1	1,269.3
Less DK_t	37.2	-	-	-	-
Less TEC_t	167.0	175.0	162.0	157.0	161.0
Distribution revenue cap formula component – DR_t	1,017.1	1,094.4	1,146.1	1,183.0	1,215.1
Distribution revenue cap formula component – DR_t ($M real as at 30 June 2017)	1,000.7	1,059.3	1,091.5	1,108.5	1,120.2

Distribution revenue	2017/18	2018/19	2019/20	2020/21	2021/22
% change in DR_t		-5.86%	-3.04%	-1.55%	-1.05%

10.17.2 Annual update of WACC

983. The introduction of an annually updating WACC[193] means the revenue caps outlined above are subject to change each year. It is expected that when Western Power is preparing a Price List for the coming financial year that a new DRP and hence WACC is calculated. The revenue model will then re-determine the revenue caps for the remaining years of the AA4 period.

984. Part of this re-determination will include updated values for TR_t, DR_t, TX_t, and DX_t terms needed to determine pricing.[194] The first year that this process is likely to occur is 2019/20[195]. The updated values for each of the terms will be specified in the relevant Price List Information.

985. It is not expected that the annual updating process will materially change the values for TR_t, DR_t, TX_t, and DX_t. The DRP is a 10 year average so each year only value is being updated. An example of the scale of impact is shown below with a hypothetical value for DRP for 2018/19 that is well above historical rates.

Table 10.39: Example impact of DRP update

Attribute	2017/18	2018/19
10 year trailing average input	1.95%	4.00%
Debt risk premium (**DRP**)	2.79%	2.82%
WACC – Nominal post-tax	6.09%	6.10%
WACC – Real pre-tax	4.38%	4.39%
Total AA4 TR_t	1,686	1,686
Total AA4 DR_t	5,380	5,386

986. As the impact is not material, it is not proposed to update the revenue at risk amounts for the determination of the SSAM rewards and penalties. The values approved in the access arrangement will remain in place for the AA4 period, despite the revenue caps changing.

193 As discussed in Chapter 9 of this AAI.

194 Note that the TX_t and DX_t terms are discussed in Chapter 11 of this AAI.

195 The 2018/19 Price List is included with this submission and is subject to approval by the ERA as part of the AA4 process.

11. Price path and network tariffs

987. This chapter outlines Western Power's network tariffs and average price path for the AA4 period. It also includes discussion of reference services and the corresponding reference tariff changes as well as the introduction of a number of new tariffs.

988. Further detail on reference services and tariffs are set out in the Price List and Price List Information provided at Appendices F.3 and F.4 of the proposed access arrangement. Further information on the tariff reform we have undertaken can be found in Attachment 11.1.

11.1 Average price path

989. Target revenue for the AA4 period is $7,888 million (real at 30 June 2017).

990. We have translated the target revenue for revenue cap services into an average price path over the five years of the AA4 period[196]. The price path is determined by smoothing the revenue over the AA4 period while retaining the net present value of the total target revenue.

991. 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 the AA4 period in present value terms. This smoothed revenue profile may be affected by the following:

- forecast energy consumption over the AA4 period
- the average price path over the AA3 period
- predictable changes in average price during the AA4 period.

992. 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.

993. 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.

994. For the AA3 period, we smoothed the revenue cap based on a price path with constant increases in average tariffs[197] across all pricing years of the period, including the first. On a weighted average basis the real increase in average tariffs over the AA3 period was 5.9 per cent each year.

995. This AA4 proposal results in an average real price increase of 2.5 per cent per year.[198] Transmission and distribution price paths are discussed separately in the sections that follow. Note that most customers are connected to the distribution network and the tariff they pay is a combination of both transmission and distribution components (often referred to as bundled tariffs).

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196 Noting that prices in 2017/18 are unchanged from 2016/17.

197 Combined average of transmission and distribution tariffs.

198 Combined average of transmission and distribution tariffs.

11.1.1 Transmission network price path

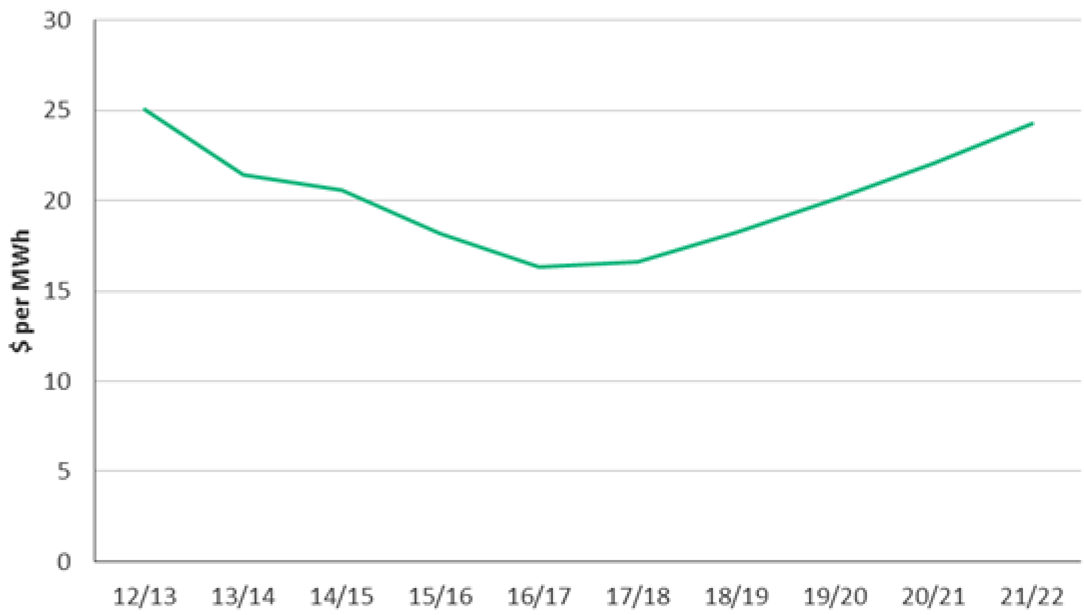
996. During the AA3 period, transmission network tariffs decreased on average by 7 per cent (nominal) per annum. This series of annual reductions resulted in the revenue to be recovered through tariffs in the final year of AA3 being much lower than the building block revenue requirement in the final year of AA3. The one year delay to the commencement of AA4 means that this situation continues for one more year.

997. The building block revenue requirement remains higher in AA4 than the revenue recovered through tariffs in the latter years of AA3. Therefore, considerable price increases are required to restore revenue recovery to be consistent with the building clock revenue requirement. Modelling suggested that transmission prices would need to increase by around 18 per cent per annum. We recognise this would have a significant impact on transmission connected customers and so we have investigated several options to minimise the problem. Ultimately we resolved to cap transmission price increases to 10 per cent (nominal) per annum.[199]

998. This issue is discussed in more detail in Attachment 10.8.

999. Figure 11.1 shows the average transmission network price path for the AA4 period.

Figure 11.1: Average transmission network price path over the AA3 and AA4 period



11.1.2 Distribution network price path

1000. During the AA3 period, distribution network prices increased on average by 7.3 per cent (real) per annum. For the AA4 period, our distribution network prices will increase on average by 1.7 per cent (real) per annum.

1001. Figure 11.2 shows the average distribution network price path for the AA4 period.

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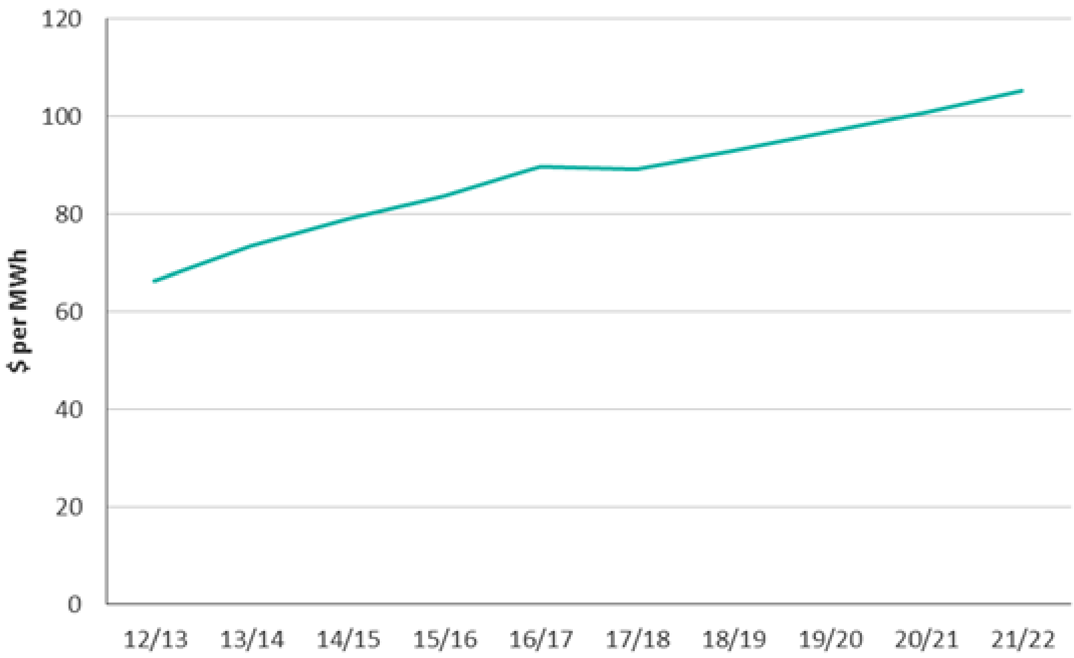
199 From AA4 commencement.

Figure 11.2: Average distribution network price path over the AA3 and AA4 period



11.1.3 Price impact on customers

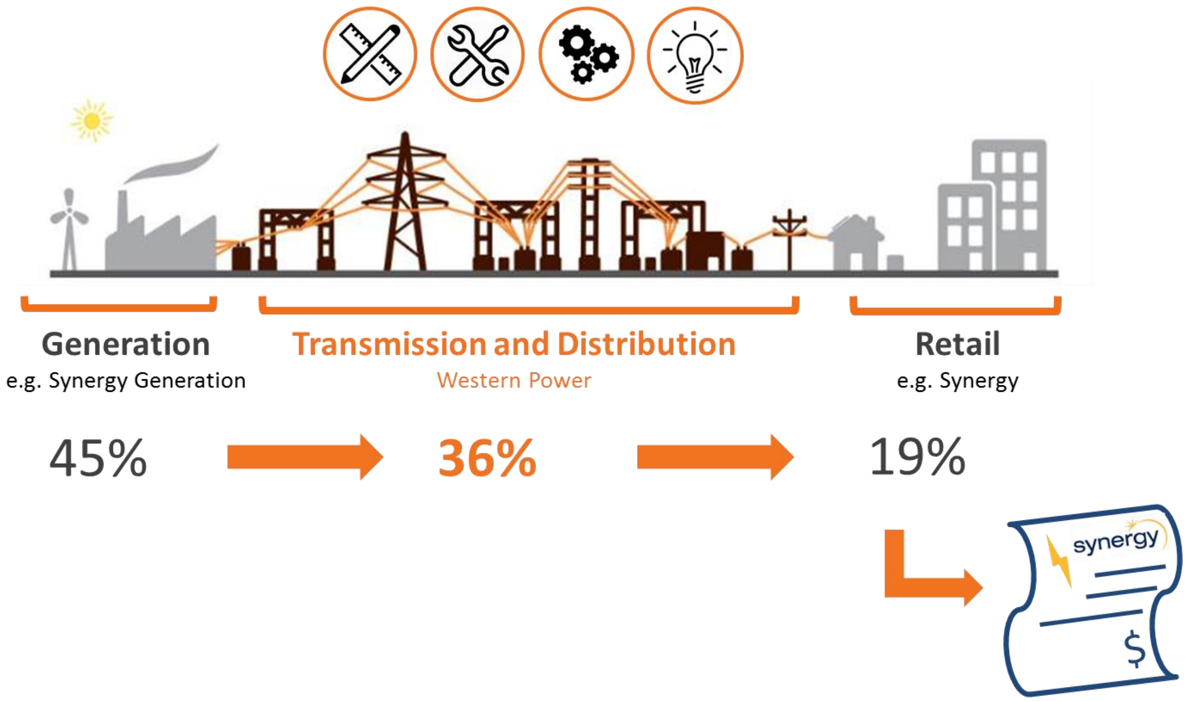
1002. Table 11.1 summarises the expected average proportional changes in reference tariffs for the users of the Western Power network from one pricing year to the next during the AA4 period.

Table 11.1: AA4 average reference tariffs, nominal per cent per annum

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 average
Distribution tariffs	0.00%	4.22%	4.22%	4.22%	4.22%	3.38%
Transmission tariffs	0.00%	10.00%	10.00%	10.00%	10.00%	8.00%
All reference tariffs	**0.00%**	**5.13%**	**5.17%**	**5.21%**	**5.26%**	**4.15%**

1003. The network tariffs are only one component of the electricity bill customers pay. Excluding TEC, the Western Power network tariff accounts for around one-third of the total costs associated with the electricity supply chain.

Figure 11.3: Western Power's role in the electricity supply chain[200]



1004. The actual impact on customers' retail tariffs resulting from changes in Western Power's network tariffs will depend on how much of any price changes retailers choose to pass through to customers. The majority of customers (including all non-contestable residential and small business customers) purchase their electricity supply from Synergy. Synergy's retail tariffs are also subject to State Government policy, and may not reflect increases in the network tariffs.

1005. Though retail tariffs are largely outside of Western Power's control, we have assessed the impact of our network tariff increases on the average customer's annual electricity bill (see Table 11.2). Note this is a high level assessment only and individual customers' bills will vary depending on usage and individual circumstances.

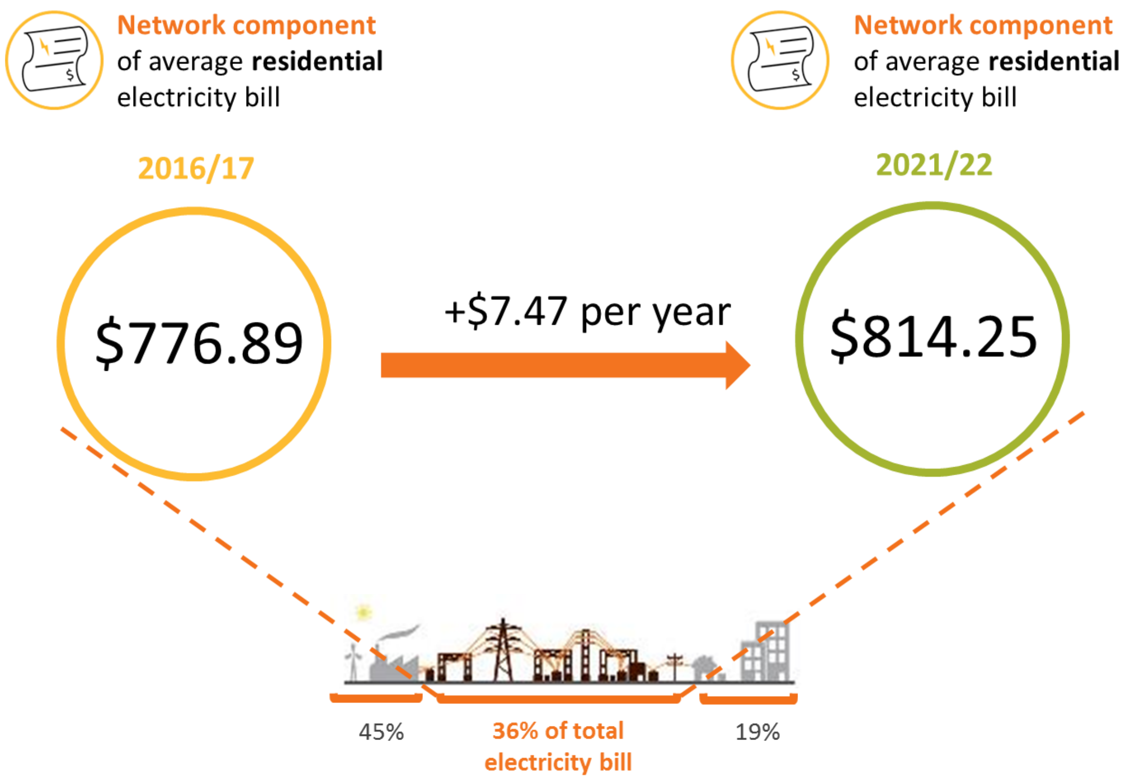
Table 11.2: Estimated annual percentage change in average electricity bills, by customer type, nominal per cent per annum

	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Residential	0.0%	2.5%	2.0%	1.4%	1.6%	0.9%
Small business	0.0%	4.0%	3. 3%	2.7%	2.9%	2.3%
All distribution customers	0.0%	19%	1.0%	0.5%	0.8%	0.3%
All transmission customers	0.0%	9.8%	9.8%	9.2%	8.8%	7.4%
All customers	0.0%	3.0%	2.4%	1.9%	2.1%	1.3%

200 36 per cent excludes the TEC, which is a cost collected by Western Power and then passed through to Horizon Power. The TEC is designed to help keep prices for regional electricity customers in line with customers served by the Western Power Network, and is mandated by State Government.

1006. Assuming the network tariff component of the average residential customer is $777, we estimate the average network component will increase by around $37 over the five years to the end of the AA4 period, or just over $7 per annum.

Figure 11.4: Estimated impact of revised network charges on the average residential electricity bill



11.2 Reference services to be provided in the AA4 period

1007. References services are the services an electricity network business offers to customers who wish to connect to the electricity network. Reference services are distinguishable from non-reference services in that reference services are covered by an access arrangement.

1008. For Western Power, reference services are those services associated with transmitting or distributing electricity. The prices, standards, and terms and conditions for these services are covered by Western Power's access arrangement.

1009. Reference services covered by an access arrangement must have an associated reference tariff, service standard benchmarks and a standard access contract. Therefore reference services are only offered to customers who hold a standard access contract. At Western Power the standard access contract is the Electricity Transfer Access Contract (**ETAC**).

1010. ETAC holders are typically generators, retailers and large loads. Though residential and small business customers are users of the network, these customers do not have an ETAC. Instead, the electricity retailer holds the ETAC on behalf of customers. Where a customer wishes to access the network, the retailer nominates the reference service Western Power is to provide. The retailer then pays the associated network reference tariff and passes those costs on to the end customer via the retail tariff.

1011. Reference services provided to residential and small use customers are administered in this way because it enables Western Power to provide reference services to a large number of customers via a single ETAC. The alternative would be to have one ETAC per residential customer and small use, which would require more than one million contracts that would largely be the same. This would not be an efficient approach.

1012. Although the retailer is the ETAC holder (and pays the reference tariff), Western Power is still providing transmission and distribution services to all customers. Therefore it is important that when developing new or revising existing reference services, Western Power engages with customers to ensure it is offering a suite of reference services that meet their requirements, as well as seeking retailers' input.

1013. Western Power has presented its views on the range of reference services and tariffs that will be offered in AA4 through the customer engagement program detailed in Chapter 4. The access arrangement review facilitates further customer engagement, as Western Power can present its proposed suite of reference services to customers via the ERA public access arrangement review process.

1014. Western Power will provide 21 reference services in the AA4 period. Each reference service has a corresponding reference tariff in the proposed access arrangement. Of the 21 reference tariffs, the structure of 15 remain unchanged from the AA4 period.

1015. We are proposing the following changes to reference services and reference tariffs for the AA4 period:

- introducing two new time of use tariffs
- introducing two new demand-based tariffs
- modifying the peak/off peak time periods in the existing RT5 and RT6 demand tariffs to reflect the time periods in the new time of use tariffs
- modifying the existing demand-based services for medium to large businesses (A5 – A8) to allow for bi-directional flows, facilitating a move to solar
- recovering the TEC from the fixed component of tariffs rather than the variable component.

1016. There are also several changes to the reference services document itself, provided at Appendix E of the access arrangement. These changes are summarised in the following sections, and also in the Price List Information provided at Appendix F.4 of the proposed access arrangement and Attachment 11.1, which summarises the approach to tariff reform and our engagement with customers and retailers.

Table 11.3 shows the reference tariffs for the AA4 period.

Table 11.3: Summary of reference tariffs for the AA4 period

Reference service	Reference tariff	Reference tariff description	Type of reference tariff	Revenue cap recovery	Retained from AA3 or new/modified changed for AA4
A1	RT1	Anytime energy (residential) tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA3
A2	RT2	Anytime energy (business) tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA3

Reference service	Reference tariff	Reference tariff description	Type of reference tariff	Revenue cap recovery	Retained from AA3 or new/modified changed for AA4
A3	RT3	Time of use energy (residential) tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA3
A4	RT4	Time of use energy (business) tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA3
A5	RT5	High voltage metered demand tariff	Reference tariff for Dx users	Tx and Dx	Modified for AA4
A6	RT6	Low voltage metered demand tariff	Reference tariff for Dx users	Tx and Dx	Modified for AA4[201]
A7	RT7	High voltage contract maximum demand tariff	Reference tariff for Dx users	Tx and Dx	Modified for AA4[202]
A8	RT8	Low voltage contract maximum demand tariff	Reference tariff for Dx users	Tx and Dx	Modified for AA4
A9	RT9	Streetlight tariff	Reference tariff for streetlights	Tx and Dx (includes streetlight operating & maintenance costs)	Retained from AA3
A10	RT10	Unmetered supplies tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA3
B1	RT11	Distribution connected generation tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA3
C1	RT13	Anytime energy (residential) bi-directional tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA3
C2	RT14	Anytime energy (business) bi-directional tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA3
C3	RT15	Time of use (residential) bi-directional tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA3
C4	RT16	Time of use (business) bi-directional tariff	Reference tariff for Dx users	Tx and Dx	Retained from AA3

201 Modifications to the reference service, not the tariff.

202 Modifications to the reference service, not the tariff.

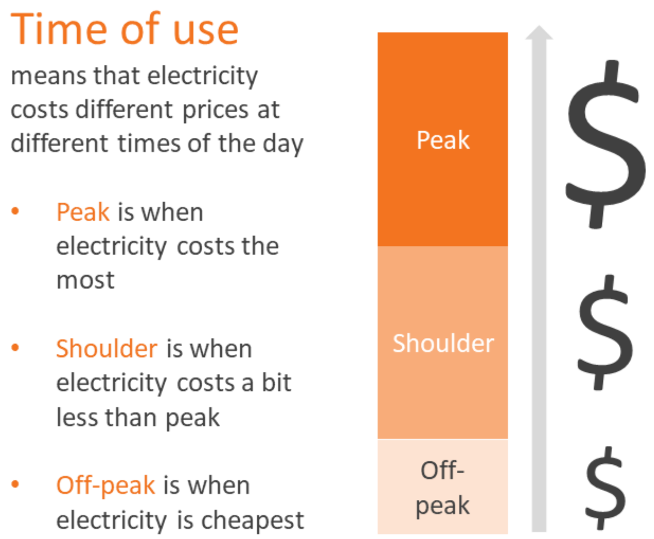
Reference service	Reference tariff	Reference tariff description	Type of reference tariff	Revenue cap recovery	Retained from AA3 or new/modified changed for AA4
D1	RT17	Time of use energy (residential) tariff	Reference tariff for Dx users	Tx and Dx	New for AA4
D2	RT18	Time of use energy (business) tariff	Reference tariff for Dx users	Tx and Dx	New for AA4
D3	RT19	Time of use demand (residential) tariff	Reference tariff for Dx users	Tx and Dx	New for AA4
D4	RT20	Time of use demand (business) tariff	Reference tariff for Dx users	Tx and Dx	New for AA4
A11	TRT1	Transmission load tariff	Reference tariff for Tx users	Tx	Retained from AA3
B2	TRT2	Transmission generation tariff	Reference tariff for Tx users	Tx	Retained from AA3

11.2.1 New time of use energy tariffs

1017. Western Power proposes to introduce time of use energy tariffs for all **new** residential and small use customers who connect to the network from the AA4 period onwards.

1018. A time of use network tariff is where customers pay a different price for using electricity at different times of the day. Currently, all residential customers pay a flat rate no matter what time of day or night they use electricity. A time of use tariff would charge a higher rate at peak times (typically late afternoon and early evening on weekdays) and a lower rate at all other times.

Figure 11.5: Time of use tariffs



1019. The purpose of a time of use tariff is to encourage customers to spread their electricity use over the course of the day. At the moment, residential customers tend to use the most amount of electricity between 3:00 PM and 9:00 PM on a weekday.

1020. Typically, people arrive home from school and work, switch on the oven, turn on the TV, do the laundry, and often use several electrical appliances. This means a lot of electricity is being distributed throughout the network at the same time, particularly on the hottest summer days when many people return home to a hot house and begin using their air conditioning. We call this time the network peak.

1021. Generally, as the population grows the network peak gets higher, which means the network must be able to cope with more and more electricity running through it. To make sure the network can cope with the peak (and so customers don't lose power), Western Power needs to reinforce and increase the capacity of the network.

1022. With a new substation costing around $45 million, investment in increasing network capacity is very expensive. It is also worth noting that the highest peaks of network demand only occur a few times per year, so the cost of increasing peak network capacity is disproportionate to the amount of time the additional capacity is required.

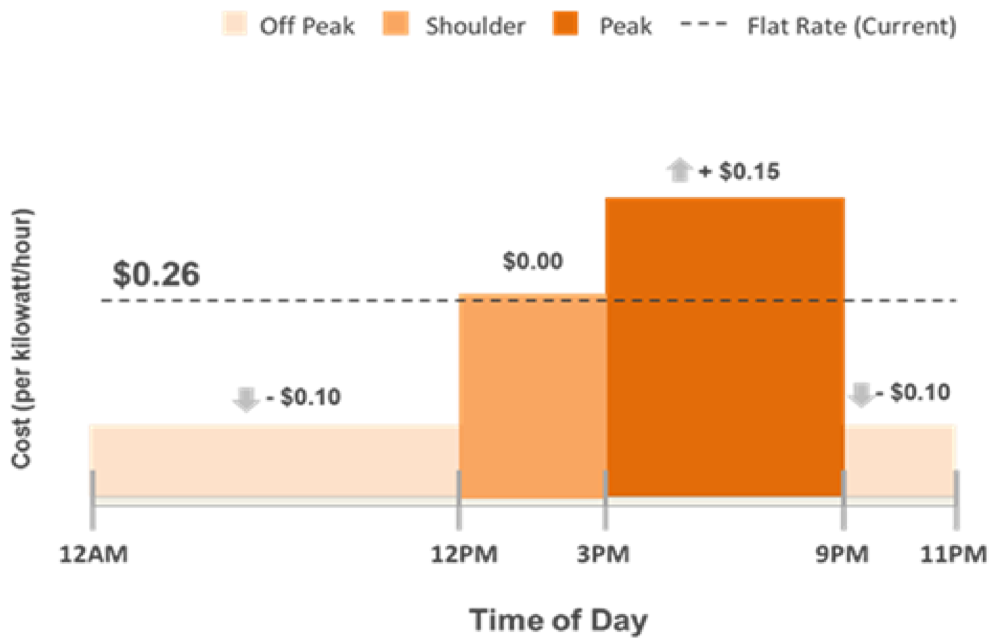
1023. Time of use network tariffs are a potential alternative to the costly option of increasing network capacity. By encouraging customers to use electricity outside of peak times, the tariffs can help reduce the need for network capacity expansion, which saves customers money over the long term.

1024. Time of use tariffs can assist customers to reduce their bills. A trial of time of use tariffs for 750 Perth households in 2011 and 2012 found that by just making a few moderate changes – washing at a different time, running the pool pump overnight, using the air-conditioning on a timer – customers saved up to $50 per annum.

1025. Time of use network tariffs can also benefit small business customers, particularly where the business is able to adjust its electricity consumption patterns. Western Power already offers a time of use tariff (RT4-Time of Use Energy) to businesses, with about 14 per cent of small businesses currently connected to the network already on the RT4 tariff.[203] The current RT4 tariff has a peak/off peak charging window of 8:00 AM to 10:00 PM on weekdays. While the RT4 tariff is beneficial to customers who can shift their electricity usage to outside these times, the peak charging window is too large to accurately reflect network peak times and encourage electricity usage outside of the typical late afternoon/early evening peak demand period.

1026. Therefore Western Power proposes new time of use network tariffs for small businesses and residential customers that better reflects peak demand times. The new tariff charges a higher rate on weekdays between 3:00 PM and 9:00 PM, and a lower rate between 9:00 PM and 12:00 AM. Customers on existing time of use network tariffs will have the option of moving to these new tariffs.

Figure 11.6: Example time of use structure



1027. As more customers take up time of use tariffs, system peaks should not grow at the same rate, reducing the need for costly peak capacity investment over the long-term.

1028. A time of use network tariff requires customers to have advanced meters (or at least electronic or interval meters[204]). From AA4 onwards, Western Power proposes all new customers will have advanced meters installed and will be put on to the time of use tariff. For existing customers, advanced meters will be installed as existing meters reach end-of-life, enabling customers to choose to move to time of use tariffs.[205]

1029. Feedback from customers on time of use tariffs has been positive. Customer forums and surveys conducted during 2016 indicates customers are generally willing to change their electricity usage behaviours once they

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203 Western Power also provides the RT3 Time of Use Energy tariff to around 12,000 residential customers, which has the same 7:00 AM to 9:00 PM peak/off peak charging window as the RT4 tariff.

204 Electronic or interval meters have the capability to record time of use, but do not have the communications links of an advanced meter, and therefore has to be read manually.

205 Note Western Power is responsible for the network tariff only, which is then passed on by the retailer. The retail tariff the customer pays is ultimately determined by retailers, therefore customers would need to approach their retailer in order to make the switch to time of use.

understand the impact of peak demand. As a result, there is appetite for time of use tariffs, particularly among younger customers.

1030. Retailers will play a major role in the effectiveness of time of use tariffs. The retail tariff structure must reflect the network tariff structure in order for time of use tariffs to give customers the appropriate price signals to shift their electricity consumption patterns. Retailers are also key to the successful roll-out of information to customers about the new tariffs. Western Power will continue to engage with retailers to ensure network and retail tariffs are aligned, and customers are fully informed of the benefits of moving to time of use tariffs.

1031. The new time of use tariffs are:

- RT17 Time of use energy (residential) tariff
- RT18 Time of use energy (business) tariff.

11.2.2 New demand-based tariffs

1032. Residential and small business customers will also be offered a demand-based tariff for the first time. Demand tariffs are similar to time of use tariffs, however a demand tariff considers a customer's maximum usage in any one 30 minute period rather than total consumption over a time period. This sends a much stronger signal about the impact customer behaviour can have on the overall system peak.

1033. As this is the first time residential customers will be offered this type of tariff, it is being offered on an opt-in basis only and will have a very small demand component to begin with to allow time for customers to understand the impact of this type of charge. This type of tariff is only possible due to the introduction of advanced meters, which allow for much more data to be captured than via a traditional meter.

1034. The initial tariff offering will charge the same tariff components of the time of use tariffs described above, albeit at a slightly reduced rate, with an additional component for the maximum demand in the peak window of 3:00 PM to 9:00 PM.

1035. The rates for the energy and demand components will be set with the intention that the average customer would pay the same under a flat rate, time of use or demand based tariff.

1036. The new demand tariffs are:

- RT19 Time of use demand (residential) tariff
- RT20 Time of use demand (business) tariff.

11.2.3 Changes to RT5 and RT6

1037. Around 4,000 medium-sized business customers operate on the existing demand network tariffs (RT5 and RT6). Western Power proposes to amend the time periods for peak and off-peak usage in the discount factor for RT5 an RT6 tariff, bringing them in line with the new residential time of use tariff discussed above.

1038. Currently, the RT5 and RT6 peak and off-peak time periods are weekdays 8:00 AM to 10:00 PM, and 10:00 PM to 8:00 AM respectively. A 14-hour peak period does not accurately reflect the actual network peak, which typically occurs between 4:00 PM and 7:00 PM on weekdays. Concentrating the peak charging time period around the time the network peak actually occurs, increases the likelihood customers would shift electricity consumption away from the network peak times. Therefore the RT5 peak and off-peak usage periods for use within the discount factor will be the same as the new residential time of use tariff. We will also adjust the operation of the discount factor to ensure these changes are revenue neutral.

11.2.4 Changes to reference services A5 to A8 to allow for bi-directional flows

1039. Currently the reference services A5 to A8 only allow for a one-way flow of electricity. They are known as exit services, and are for businesses that operate as a load at all times. Over the AA3 period Western Power received numerous requests from retailers to create a variation of these reference services that allow for bi-directional flows. This is largely driven by the increase in installations of solar photovoltaic systems by commercial customers.

1040. The reference tariffs for these services are already demand based, therefore no changes to tariff structures are required to accommodate this amendment. Changes to the reference services are detailed in Appendix E of the proposed access arrangement.

11.2.5 Changing how the Tariff Equalisation Contribution is recovered

1041. Each tariff consists of a fixed and variable component. The fixed tariff component is essentially a standing charge, payable by all customers regardless of how much electricity they consume.

1042. In recent regulatory reviews, Western Power and other network operators have increased the fixed tariff component at a higher rate than the variable component. This is because most of a network business' costs are fixed.

1043. In line with the premise of cost reflectivity, it is reasonable that the fixed component of a network tariff reflects the fixed costs of running the network. Historically, the fixed charges increased from 27 per cent for an average bill to 40 per cent over AA3. It should be noted that these fixed charge increases were offset by variable charge decreases, meaning that the change is revenue neutral.

1044. For the AA4 period, Western Power proposes to increase the fixed component of all network tariffs, offset by decreases in variable components. The main driver for the increase is to recover the TEC from the fixed component of the network tariff rather than the variable component.

1045. The TEC is a payment, gazetted by State Government, which Western Power collects via its network tariffs, and is directed to Horizon Power. The TEC is essentially a subsidy designed to ensure customers located in regional Western Australia (supplied by Horizon Power) pay the same price for electricity as customers connected to the South West Interconnected System.

1046. For most tariffs, the TEC is currently fully recovered from the variable network tariff components. This is despite the TEC being to all intents and purposes a fixed and unavoidable cost, determined by State Government. Therefore Western Power considers it reasonable that the TEC should be wholly collected via the fixed tariff component. Recovering the TEC from fixed tariff components would also mean the regional subsidy is shared equally by all Western Power customers.

1047. In most cases, customers will be no worse off as a result of the increased fixed charges. This is because there would be an offsetting decrease in variable charges.

1048. The forecast changes in the fixed and variable components of each tariffs are detailed in the Price List Information provided in Appendix F.4 to the proposed access arrangement.

11.2.6 Changes to the reference services document

1049. The reference services are documented in Appendix E of the proposed access arrangement. This document sets out all of the services we offer, including the eligibility criteria, reference tariff, service level and applicable contract for each service.

1050. Unlike the rest of the policies and contracts attached to the proposed access arrangement, the AA3 reference services document had very little additional information such as definitions and how to interpret the document. This has led to implementation issues over the course of the AA3 period.

1051. The revised reference services document now has definitions for all terms used in the document. This should provide clarity around which customers are classified as residential, voluntary/charity or business. In addition, all of the new services and modifications to services discussed above have been incorporated into the document.

11.3 Prudent discounts

1052. Western Power proposes no changes to the prudent discounting policy. The current policy will apply for the AA4 period. The prudent discounting policy is provided at section 6.6 of the proposed access arrangement.

1053. 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.

1054. Where a user can demonstrate with sufficient detail[206] 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.

1055. 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.

11.4 Discounts for distributed generation

1056. Western Power proposes no changes to the policy on discounts for distributed generation. The current policy will apply for the AA4 period. The policy on discounts for distributed generation is contained in section 6.7 of the proposed access arrangement.

1057. 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.

1058. The discount given to distributed generation is based on our avoided costs from a net present value (**NPV**) calculation 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

206 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.

and capital expenditure requirements under the *'with'* and *'without'* generator connection scenarios over a period of at least 10 years.[207]

1059. 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 available 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 per cent of the user's tariff.

11.5 Side-constraint to limit annual tariff changes

1060. Western Power has included a side-constraint to limit annual changes to individual reference tariffs during the AA4 period. The purpose of the side-constraint is to mitigate the effects of price shock on individual customers during the AA4 period.

1061. 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.

1062. Our use of side-constraints includes an adjustment to explicitly account for the recovery of the TEC payable to the State Government. A separation of the TEC adjustment is required because the amount Western Power is obligated to recover through TEC is gazetted by State Government from time to time. It is appropriate that Western Power's ability to match the revenue amount recovered from reference tariffs with the amount payable through TEC is not limited by the side-constraint.

1063. As noted in Chapter 10, the revenue caps and prices, will vary annually in line with the annual update to the WACC. Under the proposed access arrangement, Western Power has the ability to recover less than the revenue cap amounts determined under the formulae described in Chapter 10. Western Power will be mindful of any material increases in revenue that may occur due to the operation of the formulae and may intentionally under-recover the revenue cap to reduce price shocks that may occur. The revenue correction mechanism can be used to ensure all revenue is recovered.

11.6 How the prices meet the pricing objectives in the Access Code

1064. Chapter 7 of the Access Code defines the pricing methods and objectives for the access arrangement. This section demonstrates that the pricing methods we have used for the AA4 period comply with each relevant section of the Access Code.

11.6.1 Recovery of forward-looking efficient costs

1065. Section 7.3 of the Access Code states:

> *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*

[207] 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.

1066. In accordance with section 7.3(a) of the Access Code, our target revenue recovers the forward-looking efficient costs of providing revenue cap services.

1067. Reference tariffs for the AA4 period recover the forward-looking costs associated with reference services, while non-reference tariffs recover the efficient costs of non-reference services. The efficient costs we incur during the provision of non-revenue cap services are recovered on a fee-for-service basis.

1068. 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.

1069. Western Power also charges customers directly to recover any portion of the costs associated with connecting that customer to the Western Power Network that do not meet the NFIT. The Contributions Policy explains how we charge these capital contributions.

11.6.2 Reference tariffs are priced between incremental and stand-alone costs.

1070. Section 7.3 of the Access Code states:

> *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.*

1071. The Price List Information provided in Appendix F.4 of the proposed access arrangement explains how our reference tariffs are calculated and how each tariff complies with section 7.3(b) of the Access Code.

11.6.3 Charges reflect the average cost of service provision

1072. Section 7.4 of the Access Code states:

> *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;*

1073. 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.

1074. We set locational prices for customers with an annual maximum demand of greater than 1 MVA. We have established zones that group areas of similar supply cost (CBD, urban, rural, mixed and mining). The tariffs we charge reflect the average cost to supply these areas and the customers' network use.

1075. 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.

11.6.4 Tariffs accommodate reasonable requirements of users collectively

1076. Section 7.4 of the Access Code states:

> *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;*

1077. 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 AA3 period) were developed through a consultative process prior to the commencement of the access arrangement. The structure of all but two of the reference tariffs from the AA3 period (RT5 and RT6) is being retained for the AA4 period.

1078. The changes for the AA4 period are:

- introducing two new time of use tariffs
- introducing two new demand-based tariffs
- modifying the peak/off peak time periods in the existing RT5 and RT6 demand tariffs to reflect the time periods in the new time of use tariffs
- recovering the TEC from the fixed component of tariffs rather than the variable component.

1079. These reference tariff changes have been shared with customers and retailers during the customer engagement process that informed this AA4 proposal. Consultation on the new tariff changes, particularly the design of any new time of use tariffs, will continue ahead of their implementation.

11.6.5 Tariff structures enable users to predict likely changes

1080. Section 7.4 of the Access Code states:

> *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).*

1081. In accordance with section 7.4(d) of the Access Code, price shocks during the AA4 period are managed by:

- 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.

11.6.6 Tariff components reflect the underlying cost structure

1082. Section 7.6 of the Access Code states:

> *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.*

1083. 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. Costs in excess of the incremental costs are recovered through tariff components that do not vary with usage.

1084. 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.

1085. The Price List Information at Appendix F.4 of the proposed access arrangement explains in detail the process that we use to set transmission and distribution reference tariffs.

11.6.7 Postage stamp pricing in certain cases

1086. Section 7.7 of the Access Code states:

> *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.*

1087. 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.

1088. 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, RT13 to RT16 and RT17 to RT20.

12. Policies and contracts

1089. This chapter summarises proposed changes to the standard access contract and three policies that form part of Western Power's proposed access arrangement. Section 5.1 of the Access Code sets out the policies and contracts that must be included in an access arrangement. They include a:

- standard access contract – section 5.1(b)
- Applications and Queueing Policy – section 5.1(g)
- Contributions Policy – section 5.1(h)
- Transfer and Relocation Policy – section 5.1(i).

1090. Western Power has proposed amendments to the standard contract and each of the policies. In most instances, the proposed changes are minor and are designed to improve clarity and applicability.

1091. The key changes proposed are to the Contributions Policy, which includes the introduction of a 15-year revenue offset for residential customers wishing to connect to the network, allowing improved accessibility for our customers. The application of headworks schemes under the Contributions Policy is also proposed to be amended to improve the consistency and transparency of Western Power's charging arrangements.

1092. Revisions to the policies and contract are discussed in the following sections. Changes to policies and the contract have been identified both internally during AA3 and via feedback from external stakeholders.

1093. Change summary reports for each document are provided in Attachments 12.1 to 12.5.

1094. Marked-up versions of the policies and the contract detailing all amendments are provided with the proposed access arrangement.

12.1 Standard access contract

1095. The standard access contract used by Western Power for the provision of reference services to customers is the Electricity Transfer Access Contract. The ETAC outlines the terms and conditions in relation to services, tariffs, invoicing and payment, a customer's provision of financial security, technical compliance, and liability.

1096. The Access Code defines that 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.

12.1.1 Summary of proposed amendments to the ETAC

1097. In preparation for AA4, Western Power has undertaken a comprehensive review of the ETAC and identified a number of changes to enhance the integrity and development of the network, and to better achieve the intent of existing provisions. All changes and the rationale for the changes are outlined in the change summary report provided in Attachment 12.1.

1098. A marked-up version of the ETAC is also provided as an attachment to the proposed access arrangement.

1099. The principal changes address the following matters:

- preserving network integrity by strengthening the provisions requiring users to keep within their contracted capacity and requiring generators (other than small customers operating small scale generators) to give advance notice to Western Power of material changes to their plant
- assisting implementation of new government policies and/or major network changes, allowing Western Power to nominate new services which will be applicable to small customers (for example to reflect a meter upgrade program)
- ensuring the liability provisions operate as intended and are not circumvented by large commercial users utilising the services but electing not to be party to contractual arrangements with Western Power
- making it clear that, where a user provides Western Power with a cash deposit, any excess cash which accrues to Western Power (for example due to interest earned) will be refunded to the user on a monthly basis and within a reasonable time
- insert a clearer mechanism (CPI escalation) for resetting of liability caps.

1100. Western Power sought feedback from stakeholders on the proposed changes to the Model ETAC in July 2017. A summary of this engagement, including stakeholder feedback and the way in which it was incorporated into the proposed policy, where appropriate, is included in the change summary report. Feedback was received from Community Energy and Synergy.

12.2 Applications and queueing policy

1101. The applications and queueing policy (**AQP**) details the processes, procedures and requirements for customers seeking and obtaining access to the Western Power Network. The AQP helps Western Power manage customer access applications in an orderly, transparent and fair manner, especially where network capacity is scarce.

1102. Substantial changes were made to improve the AQP for the AA3 period. The changes resulted in a significant improvement to how our customers connect to the network, and we plan to build on this through the proposed changes outlined below.

1103. The objectives of the AQP are as follows:

(a) *To provide an equitable, transparent and efficient process for assessing the suitability of plant and equipment to connect to Western Power's network and to make access offers based on that assessment; and*

(b) *To undertake assessments and to provide shared network access offers that facilitate access by generators and loads to the WA Electricity Market (WEM) on an economically efficient and non-discriminatory basis that is consistent with WEM requirements, and uses a process that is equitable, transparent and efficient; and*

(c) *Where feasible and cost-effective, to facilitate joint solutions for connection applications.*

1104. We have proposed 26 amendments to the AQP as well as some administrative changes to improve its application. These amendments have been developed in consultation with our stakeholders and through our experience implementing the AQP during AA3.

1105. Western Power sought feedback from stakeholders on the proposed changes to the AQP as part of the generator forum in May 2017, and again in August 2017. A summary of this engagement, including stakeholder feedback and the way in which it was incorporated into the proposed policy where appropriate, is included in the AQP Stakeholder Engagement Report provided as Attachment 12.2 (for the first round of engagement) and in the change summary report provided as Attachment 12.3 (for the second round of engagement).

1106. Feedback was received from Perth Energy, Lacour Energy and Synergy.

1107. There are four categories of key changes:

1. connection applications
2. transfer applications
3. common provisions
4. minor amendments.

12.2.1 Connection applications

1108. The proposed amendments relating to connection applications are designed to further improve the efficiency of the AQP process. Some of these include:

- making spare capacity more readily available to non-competing applications group (**CAG**) members
- withdrawing dormant applications from access queues
- providing customers with more options for their connection application when their circumstances change
- providing more clarity around the preliminary access offer (**PAO**) process
- providing Western Power with the ability to terminate CAGs when a network access solution is not viable – rather than the CAG existing in perpetuity
- wording changes to make the policy clearer.

1109. A summary of the key changes is provided in Table 12.1 and further detail (including in respect of other connection application related changes) is provided in the change summary report provided in Attachment 12.3.

1110. A marked-up version of the policy detailing all amendments is also provided with the proposed access arrangement.

Table 12.1: Summary of proposed changes to AQP connection applications

Policy clause / section	Description	Summary of proposed change and benefit
24.8	Occasionally, spare capacity becomes available without any applicant funded shared works e.g. through growth driven network augmentation or through a reduction in existing contracted load or generation capacity. As the formation of a CAG relies on the identification of shared works, the CAG mechanism cannot currently be used to release this capacity to competing applicants.	Introduce a new clause enabling spare network capacity to be offered to applicants (both those who are members of a CAG and those who are not) on a first come first served basis until no spare capacity remains. This amendment allows spare capacity to be allocated to customers in a timely and cost efficient way.
3.14	The AQP does not contain provisions regarding termination of dormant applications. The AQP provides that applications do not expire due to the passage of time. Applicants can remain in the process indefinitely although no action is being taken to progress their connection applications.	Insert a provision to enable dormant applications to be withdrawn. This enables better network planning and helps to ensure Western Power resources are not being unnecessarily allocated to applications that are not progressing.
24.3 and 24.5(a)	In responding to a notice of intention (**NOI**) to prepare a preliminary PAO or to a PAO, there is no option for a CAG member to elect to opt out of that CAG but still maintain the application priority date so as to participate in another CAG that is already in existence or to be formed in the future. This may force applicants to accept an unwanted NOI or PAO to avoid paying for an applicant-specific solution or have their connection application withdrawn.	Include a new clause to provide another option for responding to a NOI. This involves the applicant advising Western Power that it does not want its application to be considered as part of the CAG to which the NOI relates, but that it wants the application to maintain its priority date and be considered for inclusion in other CAG.

Policy clause / section	Description	Summary of proposed change and benefit
24A.2	The AQP allows a successful project tenderer to be given the same priority date as an unsuccessful tenderer with the earliest priority date. This can be particularly problematic where a CAG is oversubscribed at the access offer stage as the successful tenderer may receive access ahead of an applicant with an earlier priority date but not involved in the tender process. The processing of applications should not be influenced by whether or not they relate to a tender process.	Delete clause 24A.2. Further amendments will be made to delete the definition of 'project' and to delete clause 3.7(a), as these provisions will no longer be necessary.
24.5	The AQP details how a CAG applicant may reject or accept a PAO, but not the consequences if an applicant chooses to not respond to the PAO at all. This creates uncertainty as to how the CAG applicants who have responded to the PAO are to be progressed.	Insert a clause to confirm that an application will be taken to have been withdrawn if the applicant does not, within 30 business days of receipt of the PAO, respond to Western Power by one of the prescribed methods. This will allow Western Power to more efficiently progress the applications of CAG members who have responded and accepted a PAO.
New	There is no clear mechanism in the AQP to terminate or disband a CAG even in situations where Western Power finds that it cannot reasonably progress the CAG solution works. In these circumstances, the CAG will remain in progress indefinitely. This creates potential issues and uncertainties for Western Power and its customers.	Include a new clause to allow Western Power to terminate a CAG by notice in writing when: • it is unlikely PAOs or access offers will be made to CAG applicants • the shared works comprising the CAG solution are no longer viable.

12.2.2 Transfer applications

1111. Western Power proposes amendments and additions to sections of the AQP relating to transfer applications. The most significant amendment relates to removing inconsistency between the treatment of contestable and prescribed customers.

1112. Currently, the AQP considers contestability on an exit point by exit point basis. Where the customer consumes (or is reasonably expected to consume) 50 MWh or more at an exit point, the customer is considered contestable. Where consumption is below 50 MWh, the customer is not contestable.

1113. This is inconsistent with the *Electricity Corporations (Prescribed Customers) Order 2007* (Prescribed Customers Order), which considers the customers portfolio of exit points. The Order provides that a customer is contestable where it has a portfolio of exit points (a hospital or university for example), and one or more of the exit points exceeds the 50 MWh threshold. Under the current AQP, the customer would only be considered contestable (and, therefore, able to purchase electricity from retailers other than Synergy) at the exit point that exceeds 50 MWh, but not at the other sub-50 MWh exit points.

1114. We propose to amend the AQP to align it with the Prescribed Customers Order**.**

1115. Other amendments to transfer applications include:

- clarifying some aspects of the AQP that have in the past caused confusion, such as the process for transfers and relocations
- wording changes to make the policy clearer.

1116. A summary of the key changes is provided in Table 12.2 and further detail is provided in the change summary report provided in Attachment 12.3.

1117. A marked-up version of the policy detailing all amendments is also provided with the proposed access arrangement.

Table 12.2: Summary of proposed changes to AQP transfer applications

Policy clause / section	Description	Summary of proposed change and benefit
13, 9.1, 14.4(c)	The AQP considers contestability on an exit point by exit point bases. Whether a customer is contestable is determined by the estimated amount of electricity to be consumed at that exit point. This approach is inconsistent with the Prescribed Customers Order which defines a 'prescribed customer' based on the customer's portfolio of exit points. This inconsistency creates issues and ambiguities for Western Power and applicants in interpreting and implementing the AQP, as the definition of whether a customer is contestable or not varies depending on whether the AQP or the Prescribed Customers Order is being applied.	Insert a new definition of 'contestable customer', which aligns with the definition of 'contestable' in the *Electricity Industry Customer Transfer Code 2016* and excludes customers who are 'prescribed customers' under the Prescribed Customers Order. Amend clause 13.1 so that when Western Power receives a transfer application, connection application or transfer request, it must determine if that application or request is being made for the purpose of supplying electricity to a contestable customer at that exit point. Similarly, amend clause 13.3 so that Western Power must reject an application if it is not authorised to make an access offer in relation to that application because the customer is not a contestable customer. Delete clause 13.2. Amend clause 9.1 regarding customer transfer requests to provide that such requests may be made in relation to exit points at which electricity will be supplied to contestable customers, not 'contestable exit points'. Delete clause 14.4(c).

Policy clause / section	Description	Summary of proposed change and benefit
New	There is some confusion in relation to how the mechanisms of the Transfer and Relocation Policy interact with the AQP. Particularly, in situations where a relocation requires network works or impacts an existing network user or applicant	Add three new clauses to confirm the following: • The Transfer and Relocation Policy (and not the AQP) applies to bare transfers and assignments of rights under an access contract. • If a user wishes to seek a relocation under the Transfer and Relocation Policy, it must lodge an electricity transfer application. • A connection application must also be lodged if the relocation requires network augmentation or other works, or would impede Western Power's ability to provide covered services to another user or applicant.

12.2.3 Common provisions

1118. Western Power has compiled a number of amendments to some of the common provisions. These amendments include:

- providing clarity around the type of applications the AQP covers (covered services only)
- improving the transparency of what information provided by customers is confidential and what can be shared with third parties
- allowing provisions for both electricity transfer applicants and connection applicants to depart from the AQP in progressing an application
- wording changes to make the policy clearer.

1119. A summary of the key changes is provided in Table 12.3 and further detail is provided in the change summary report provided in Attachment 12.3.

1120. A marked-up version of the policy detailing all amendments is also provided with the proposed access arrangement.

Table 12.3: Summary of proposed changes to AQP common provisions

Policy clause / section	Description	Summary of proposed change and benefit
New	The AQP does not expressly state that it applies only to applications in relation to covered services.	Amend wording throughout the AQP to make it explicit that the policy applies only to applications for services covered by the AQP.
New	Occasionally, Western Power must disclose information to third parties to inform them about competing applications and network constraints that may affect their connection application. There is some uncertainty in the AQP about whether some of this information is classified as confidential.	Remove the uncertainty around what customer information is confidential and what may be shared with third parties.
2.2, 7.4,	Electricity transfer applicants can depart from the AQP in progressing their applications, provided that doing so causes no impediment to other applicants. However, there is no equivalent provision in relation to connection applications.	Amendments to provide consistency and the same flexibility for both the electricity transfer applications and connection applications.
4.8(a)	The AQP provides that Western Power and an applicant 'may not' (which in this context has the effect of 'must not') enter into an access contract containing a condition precedent with a period for satisfaction longer than eight months. Additional flexibility is required to enable Western Power to agree to a conditions precedent with a period for satisfaction longer than eight months, where reasonably necessary.	Amend the wording of this clause to more accurately reflect the purpose and to include an exception to allow a longer period for satisfaction, where reasonably necessary.

12.2.4 Minor amendments

1121. Several other minor amendments are proposed to the AQP. These amendments relate to such things as updating or deleting references, diagrams, punctuation and definitions.

1122. All minor amendments can be seen in the marked-up copy of the AQP provided with the proposed access arrangement.

12.3 Contributions policy

1123. The Contributions Policy details how Western Power charges customers seeking to establish a new or upgrade an existing connection to the network.

1124. Western Power proposes to make a number of changes to this policy to enhance its clarity and make connecting to our network more accessible. We have also removed parts of the policy that are out of date and redundant.

1125. It is important that the Contributions Policy meets the needs and interests of Western Power as well as our customers and stakeholders. The objectives of the contribution policy as defined in the Access Code are that:

(a) in respect of a required augmentation, it strikes a balance between the interests of:

(i) the contributing user; and

(ii) other users; and

(iii) consumers;

and

(b) it does not constitute an inappropriate barrier to entry.

1126. All changes and the rationale for the changes are outlined in the change summary report provided in Attachment 12.4.

1127. The key changes to the Contributions Policy are described in the following sections.

12.3.1 Making revenue offset available to our residential customers

1128. The most significant change proposed to the Contributions Policy involves Western Power expanding the provision of the revenue offset to also include residential customers. This means we will estimate the amount of incremental revenue resulting from the new residential connection over a 15-year period, and deduct this from the upfront capital contribution payable by the customers. This brings residential customers into line with commercial customers who are already eligible for an offset of up to 15 years, depending on the nature of the commercial project.

1129. The proposed change recognises that over time, like commercial customers, residential customers making a new connection to the distribution network contribute to Western Power's network tariff revenues. Extending the revenue offset to our residential customers means the initial cost of connection could be more affordable for more people, as they will have to pay less upfront.

12.3.2 Removing the distribution headworks scheme

1130. We propose to remove the distribution headworks scheme from the policy. A headworks scheme is not a mandatory requirement of the Access Code.

1131. The distribution headworks scheme was introduced for the AA3 period, with the purpose of providing a levelised $/kVa charge for upgrades to power supply in rural and regional areas situated 25 kilometres or more from the nearest Western Power substation. Under the scheme, Western Power recovers only a portion of the cost for supply upgrades upfront, with future connections forecast to contribute the balance.

1132. The outstanding costs rarely meet the NFIT (due to being outside natural load growth scenarios) and, given the lack of growth in regional areas, the upgrade costs are rarely recovered from the actual customer or customers served. Instead, these costs are being recovered from all customers (where the costs meet NFIT) or borne by Western Power directly (where the costs do not meet NFIT). For this reason we propose to remove the scheme.

1133. Charges for customers who may have previously been subject to the distribution headworks scheme charges will be determined consistent with the methodology applied to supply upgrades in regional areas. That is, we will determine the additional costs associated with connecting the customer and calculate a charge designed to recover those costs less an amount representing the portion of the costs that are assessed as meeting NFIT.

12.3.3 Expanding the distribution low voltage connection headworks scheme

1134. The distribution low voltage connection headworks scheme (**DLVCHS**) was developed to allow the cost of infrastructure required for connection upgrades to be shared more evenly by all customers using the installed network.[208]

1135. The DLVCHS imposes charges on customers based on requested capacity rather than on whether the current network will have to be expanded because of the submitted application. This means the first customer to request an increase in capacity is not required to fund infrastructure upgrades in their entirety.

1136. Currently, the DLVCHS applies only to connection upgrades and not to new connections. Western Power proposes to broaden the application of the DLVCHS to all new capacity connections (excluding the connection of gifted assets). Expanding the scheme will:

- enable the development industry to more accurately forecast charges
- implement consistent charging across customers
- provide customers with more predictable and transparent prices
- streamline the processes for determining charges by providing a simpler approach to charging customers.

1137. A summary of the key changes is provided in Table 12.4 and further detail is provided in the change summary report provided in Attachment 12.6.

1138. A marked-up version of the policy detailing all amendments is also provided with the proposed access arrangement.

[208] The DLVCHS covers connections within 25km of the nearest zone substation.

Table 12.4: Summary of changes to the Contributions Policy

Policy clause / section	Description	Summary of proposed changes and benefit
4.3	Security clauses	Amend the existing security clauses to clarify when and for how long security may be held by Western Power. This will make it easier for customers to understand the terms of the policy. Western Power is proposing to review the security provided by a customer 24 months following service commencement.
6	The distribution headworks scheme applies for supply upgrades to customers in regional areas (25km or more from nearest substation). The scheme provides a levelised charge for such supply upgrades.	Remove the distribution headworks scheme as it leaves Western Power liable for the remainder of the costs to upgrade the network – where these costs do not meet NFIT. Western Power will determine the additional costs associated with connecting the customer and calculate a charge designed to recover those costs less an amount representing the portion of the costs that meet NFIT
7 (now section 6)	Application of the DLVCHS allows for the cost of infrastructure required for new customer connections to be shared by all customers using the installed network. The DLVCHS provides a charge based on requested capacity (kVA) rather than on whether the current network will have to be expanded because of the submitted application (i.e. does not require the first customer to fully fund the network expansion).	Broaden the application of the DLVCHS to all new capacity connections (excluding the connections of gifted assets), not just connection upgrades as per the current policy. This will improve cost forecasting for connecting customers, consistency in charging. Customers will also benefit from greater pricing certainty.
5.2	The new connections revenue offset is currently provided only to commercial customers, with revenue generally calculated over a 15-year period and deducted from the capital contribution.	Expand the provision of the revenue offset to include residential customers. The change will reduce the cost to residential customers connecting to the network.

12.4 Transfer and relocation policy

1139. The Transfer and Relocation Policy defines the terms and conditions for capacity transfers and relocations between customer connection points. The policy is applicable to customers already connected to the network, looking to relocate where they access services or to transfer their services to another party.

1140. Western Power proposes some minor changes to the Transfer and Relocation Policy. The changes will act to:

- ensure closer alignment with the provision of the Access Code
- ensure defined terms are consistent with other regulatory policies and documents (such as the AQP)
- boundaries with other regulatory policies and contracts are distinct
- make the relationship between the AQP and relocations under the Transfer and Relocation Policy clearer, particularly the fact that relocations of services require an application under both instruments
- better define the criteria relevant to whether Western Power gives consent to a requested transfer or relocation under the Transfer and Relocation Policy
- enhance the transparency of the obligations and rights of involved parties.

1141. Several minor amendments are also proposed to the Transfer and Relocation Policy. All amendments are detailed in the change summary report provided in Attachment 12.6, and in the marked-up copy of the Transfer and Relocation Policy provided with the proposed access arrangement.

1142. Western Power sought feedback from stakeholders on the proposed changes to the Transfer and Relocation Policy following the generator forum in May 2017, and again in July 2017. A summary of this engagement, including stakeholder feedback, and the way in which it was incorporated into the proposed policy where appropriate, is included in the change summary report.

13. Supplementary matters

1143. Except for some minor amendments, Western Power proposes to retain the supplementary matters in section 9 of the current access arrangement.

13.1 Regulatory framework

1144. Supplementary matters listed in section 5.27 of the Access Code are:

> *(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.*

1145. Section 5.28 of the Access Code requires an access arrangement to deal with a supplementary matter in a manner which is consistent with, and to facilitate the treatment of the matter in *written law*.[209]

13.2 Proposed amendments

1146. There have been significant changes to electricity industry governance and market structures since the Access Code was developed. For example, the WEM was established in 2006 and has evolved significantly over the past decade.

1147. As such, many of the supplementary matters defined in the Access Code now relate to WEM functions rather than Western Power's activities. Several of Western Power's functions such as balancing and trading have transferred to the AEMO. Western Power's role is now more that of a traditional network operator and meter data agent under the WEM Rules.

1148. Western Power therefore proposes revisions to the access arrangement to clarify that it:

- does not have any direct requirements to perform balancing, ancillary services, stand-by, trading or settlement functions, but
- will continue to fulfil its obligations as a network operator and meter data agent under the WEM Rules and Technical Rules to support the AEMO in performing its functions, including by providing network and metering information.

1149. Western Power also proposes to update the version of *Electricity Industry (Metering) Code* referenced in the access arrangement to reflect the current 2012 version.

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209 Written law is a defined term in the Access Code.