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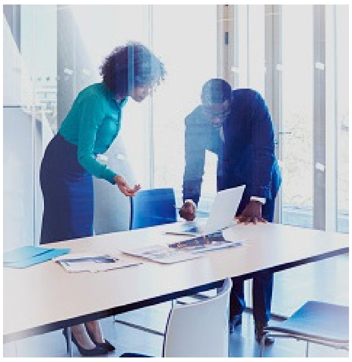

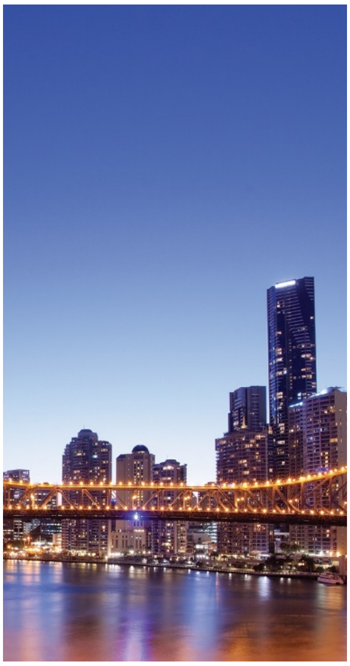

Technical Review of Western Power Proposed AA4 Access Arrangement for 2017/18-2021/22

Economic Regulation Authority

Final Report

26 April 2018

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Glossary

Acronym	Description
AA3	Third Access Arrangement
AA4	Fourth Access Arrangement
AA5	Fifth Access Arrangement
AAI	Access Arrangement Information
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIP	Asset Investment Planning
AMF	Asset Management Framework
AMI	Advanced Metering Infrastructure
AMS	Asset Management System
ARDS	Rules Engine
ARIMA	Autoregressive Integrated Moving Average
AWOTE	Average Weekly Ordinary Time Earnings
BAU	Business as Usual
BST	Base-Step-Trend top-down OPEX forecasting method
BTP	Business Transformation Program
BUCC	Backup Control Centre
CAGR	Compound Annual Growth Rate

Acronym	Description
CAPEX	Capital Expenditure
CB	Circuit Breaker
CBA	Cost Benefit Analysis
CPI	Consumer Price Index
CRAM	Cost and Revenue Allocation Method
CRM	Customer Relationship Management
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DQM	Distribution Quotation Management
DSLMP	Dedicated Streetlight Metal Poles
DTC	Distribution Transfer Capacity
EGWWS	Energy, Gas, Water and Waste Services
EMS	Energy Management System
EPCC	East Perth Control Centre
ERA	Economic Regulation Authority of Western Australia
ERP	Enterprise Resource Planning
FRZ	Fire Risk Zone
GBA	Geoff Brown & Associates
GEC	General Electric Company
GIS	Geographical Information System
GSL	Guaranteed Service Level
GSM	Gain Sharing Mechanism
GWh	Gigawatt hour
HRIS	Human Resource Information System

Acronym	Description
HV	High voltage
IAM	Investment Adjustment Mechanism
ICT	Information and Communication Technology
IEEE	Institute of Electrical and Electronics Engineers
IMO	Independent Market Operator
IRR	Internal Rate of Return
IVM	Integrated Vegetation Management
kV	kilo-volt
kW	Kilowatt
LOS	Loss of Supply
LOSEF	Loss of Supply Event Frequency
LSE	Least Squares Estimator
LV	Low voltage
MED	Major Event Day
MRL	Mean Replacement Life
MPFP	Multilateral Partial Factor Productivity
MTFP	Multilateral Total Factor Productivity
MVA	Megavolt amp
MW	Megawatt
NDP	Network Development Plan
NEM	National Electricity Market
NER	National Electricity Rules
NFIT	New Facilities Investment Test
NIEIR	National Institute of Economic and Industry Research

Acronym	Description
NMP	Network Management Plan
NMS	Network Management System for management of telecommunications network
NPV	Net Present Value
NRMT	Network Risk Management Tool
NSP	Network Service Provider
OEF	Operating Environment Factor
OH HV	Overhead High Voltage
OLS	Ordinary Least Squares
OPEX	Operating Expenditure
POE 10	10% Probability of Exceedance
POE 50	50% Probability of Exceedance
PoW	Program of Work
PPE	Property, Plant and Equipment
PUO	Public Utilities Office
PV	Present Value
RAB	Regulated Asset Base
RBA	Reserve Bank of Australia
REPEX	Replacement Expenditure
RIN	Regulatory Information Notice
SaaS	Software as a Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SFA	Stochastic Frontier Analysis

Acronym	Description
SMI	System Minutes Interrupted
SOO	Statement of Opportunities
Solar PV	Solar Photovoltaic
SSAM	Service Standard Adjustment Mechanism
SSB	Service Standard Benchmark
SST	Service Standard Target
STPIS	Service Target Performance Incentive Scheme
SUPP	State Underground Power Program
SVC	Static VAR Compensator
SWER	Single-wire earth return
SWIN	South West Interconnected Network
SWIS	South West Interconnected System
The Code	Electricity Networks Access Code 2004
TOU	Time-of-Use tariff
VCR	Value of Customer Reliability
WPI	Wage Price Index

Executive summary

i. Introduction

Western Power submitted to the Economic Regulation Authority (the ERA) revisions to its Access Arrangement on October 2, 2017. These revisions are to apply from July 2017 until June 2022. The Electricity Networks Access Code 2004 (the Code) sets out the requirements for Western Power's Access Arrangement including subsequent revisions.

The ERA has commissioned GHD (our/us/we) to undertake a review of the prudency and efficiency of Western Power's proposed capital and operating expenditure for the period July 2017 to June 2022 together with a review of Western Power's governance and expenditure management processes, GSM, service standards and benchmarks and adjustment mechanism.

This report details our review and conclusions from that review.

ii. Western Power proposal

The Western Power proposal for the fourth access arrangement (AA4) included the following provisions (in $ real direct costs at 30 June 2017 terms):

Distribution CAPEX	**$2,448.3 million**
Transmission CAPEX	**$784.2 million**
Corporate CAPEX	**$487.1 million**
Network OPEX	**$1,805.1 million** (including real escalation and indirect costs)

The AA4 proposal represents a $400 million reduction in total capital expenditure (CAPEX) and $584 million in operating expenditure (OPEX) from the actual expenditure incurred during the third access arrangement (AA3). In developing the AA4 proposal, Western Power has been cognisant of feedback received through its customer engagement program, using this to develop key drivers for targeted CAPEX and OPEX expenditure to optimise the risk return on expenditure whilst minimising the overall cost to the customers

The main CAPEX programs proposed for AA4 include:

- Wood pole management program
- Advanced Metering Infrastructure (AMI) project
- Modernisation of existing depots and development of new site
- Replacement of obsolete Supervisory Control and Data Acquisition (SCADA) & Communications assets

Other significant initiatives in the AA4 proposal are:

- Continuing to build on efficiency gains from the Business Transformation Program (BTP) through the optimisation of CAPEX and OPEX programs and projects, and corporate practices
- Upgrades to Information and Communication Technology (ICT) systems including an upgrade to Ellipse
- Installation of a microgrid at Kalbarri to address reliability issues, and establishing a microgrid construction model that may be deployed elsewhere in the Western Power network to address similar performance issues

- Transferring of fleet to the regulated asset base

iii. Capital governance

We have assessed Western Power's governance policies, processes and procedures, including:

- the Investment Governance Framework;
- the Portfolio Management Standard; and,
- the Investment Management Standard (as well as other supporting documents).

We find that these documents provide a good basis for governance of investment decisions and project delivery, and that they address the principles of good governance well. We also find that the application of the policies, processes and procedures is in accordance with the relevant standards and guidelines.

Western Power has invested in various parts of the business to improve issues raised during an AA3 governance review. Investment in the asset management framework (AMF) has led to strengthened asset condition data. Western Power has also developed the Network Risk Management Tool (NRMT), a quantitative risk assessment tool, the lack of which was previously identified as a weakness.

We recommend that Western Power simplifies its currently complex process used in evaluating smaller capital projects. This will provide an improved balance between the correct implementation of governance and the benefit derived from governance.

The top-down approach adopted by Western Power is inherently inflexible, and is open to the risk of sub-optimal investment decisions during funds allocation. While this inflexibility has not manifested itself thus far, this should be monitored closely by senior management and the Board.

While OPEX is closely monitored by Western Power at present, we recommend the preparation and utilisation of OPEX governance documents. These should be closely aligned with the Investment Governance Framework, and should outline the process from strategy to execution, including appropriate measurements of performance.

iv. Asset management

We have conducted a review of Western Power's asset management strategies, including assessment of:

- the level of maturity and effective integration of asset management practices within the business
- the effectiveness of how data, information and business processes lead to sound decision making to balance, risk, service levels and costs and how well these decisions align with the business objectives and customer needs
- the asset strategies for capital renewal and compliance projects and maintenance expenditure requirements which underpin the 10-year forecast capital and operating budgets and the revenue requirements for the AA4 period.

We concluded that the level of maturity and effective integration of asset management practices within the business has significantly strengthened over the AA3 period and that Western Power would now be considered as having an industry leading asset management system in place.

We concluded that Western Power should reconsider defining the percentage of assets above one standard deviation above the Mean Replacement Life (MRL) as the benchmark to indicate heightened risk associated with the population of each asset class. We also recommend that Western Power shows measures of asset utilisation. These measures for substation and feeder capacity can provide an indication of capital investment efficiency. Specifically, these could take the form of asset utilisation (principally zone substation transformer utilisation) or spare capacity invested to provide for growth, because in times of low growth it will become more important to be capital efficient with respect to sustaining capital expenditure.

The Australian Energy Regulator (AER) publishes an Annual Benchmarking Report which uses a multilateral total factor productivity (MTFP) approach to compare efficiency between electricity NSPs. The capital partial productivity factor measures the annual cost of capital invested in the network to supply the services. For distribution network service providers (DNSPs) the benchmarking uses five inputs; overhead sub-transmission lines, overhead distribution lines, underground sub-transmission cables, underground distribution cables and transformers.

We recommend measuring asset utilisation for these five categories. This would provide approximate indicators of capital productivity and by excluding the length of lines and cables from the indicators, it can serve Western Power to demonstrate efficient use of capital compared with other NSPs with different load density and geographic coverage.

We have determined that the information and business process tools and systems developed for asset management are effective in improving asset strategies and managing risks related to the network assets. Improvement requirements in the accuracy of the data is recognised by Western Power however there appears to be improvements that can be made in the application of the tools to the different classes of assets.

Western Power has developed IT solutions to assist with its asset management process, allowing it to more accurately and consistently quantify risk and maintain oversight of the condition of its assets and associated investment activities. We expect that as data accuracy improves along with the implementation of advanced ICT systems that further refinement of asset strategies and delivery processes will have the potential to improve efficiencies during AA4 and into the next fifth Access Arrangement (AA5) period.

A key attention area for Western Power over the course of the AA4 period will be in preparing for how new technology is likely to play a significant role in the future of Western Australia's electricity systems over the coming years, and how Western Power has to adapt to these changes for the benefit of its customers. We consider that Western Power is preparing for this change as evidenced by proposed investments in ICT, SCADA and Communication systems and which aligns with customer feedback.

We consider the asset management practices adopted by Western Power to be industry leading and that asset strategies are being improved to target the specific higher risk segments of each of classes of network assets. The challenge is to improve data accuracy and consistency, and tools and practices which enable Western Power to efficiently analyse and revise strategies to inform their asset management decisions.

v. Forecasting method

We have reviewed the basis of the 2017 demand forecast after reviewing written documentation of:

- forecast preparation methods, processes and quality reviews
- overall network energy, customer numbers and peak demand forecasts
- maximum demand forecast by zone substation

A third party review of the 2016 demand forecasts was undertaken by National Institute of Economic and Industry Research (NIEIR) (August 2016), which found that Western Power's method, processes and assumptions underlying the energy, customer number and peak demand forecasts were reasonable, robust and fit for purpose. The review made some suggestions for improvement, most of which were incorporated into the 2017 forecast preparation process.

Table 1 contains Western Power's forecasts of average customer numbers and energy consumption, conducted in 2017.

Table 1 Western Power forecast average customer numbers and forecast energy consumption

Western Power 2017 forecasts	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 average annual growth
Average customer numbers	1,115,509	1,134,897	1,154,255	1,173,585	1,191,890	1.6%
Grid supplied energy consumption (GWh)	17,698	17,663	17,628	17,502	17,309	-0.6%

Western Power's forecast maximum demand is displayed in Table 2.

Table 2 Forecast maximum demand (MW)

Western Power 2017 forecasts	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 average annual growth
Maximum Demand – Network POE 10 (MW)	3,991	3,939	3,951	3,926	3,896	-0.6%
Maximum Demand – Network POE 50 (MW)	3,859	3,811	3,792	3,786	3,746	-0.8%

Western Power has advised that it has implemented three of these five recommendations in preparation of the 2017 forecasts. We believe these include the use of a top-down model, segmentation into base and temperature sensitive demand components, and direct incorporation of weather correction. The two remaining refinements yet to be implemented may provide additional confidence in the forecasts but are unlikely to materially change the outcomes.

We accept the Western Power AA4 demand forecast as sound, and reasonable.

vi. Forecast CAPEX

We have adopted a sampling approach to forecast CAPEX analysis, aiming to review a representative cross-section of CAPEX projects. This includes:

- distribution and transmission projects from each of the CAPEX categories (asset replacement, compliance, growth and improvement in service)
- projects of various sizes
- projects that constitute 50% of the total CAPEX
- specific projects/programs of interest, such as Distribution wood pole replacement program

For distribution CAPEX, the following CAPEX projects were selected for analysis:

Asset Replacement	• Pole Management • Conductor Management • Metering • State Underground Power Program (SUPP)
Compliance	• Pole Management • Bushfire Management • Conductor Management
Growth	• Distribution Capacity Extension • Network Extension
Improvement in Service	• Kalbarri microgrid project

For transmission CAPEX, the following CAPEX projects were selected for analysis:

Asset Replacement	• Power Transformers • Primary Plant • Switchboards
Compliance	• Substation Security • Poles and Towers
Growth (addressing supply, thermal management and voltage)	• T0362344 CBD New Substation • T0362480 CBD Hay/Mulligan Supply Reinforcement • Kemerton 3rd Transformer • NBT – Install Line Reactors • T0357957 PIC-BSN: Const New 132 kV line
Improvement in Service	• SCADA & Communications

Distribution

In analysing Western Power's proposed distribution CAPEX, we have made the following recommendations:

- amended conductor management forecast based on alternate unit rates
- reduced meter volumes by 23% for AMI program
- disallowance of proposed incremental SCADA & Communications as part of AMI project

Table 3 contains our recommended distribution CAPEX for AA4.

Table 3 Recommended AA4 Distribution CAPEX forecast ($M direct costs at 30 June 2017)

Distribution CAPEX	Proposed AA4 CAPEX	Alternate AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Asset replacement	1,139.4	245.1	232.1	219.4	197.1	205.4	1,099.1
Regulatory compliance	150.3	22.9	36.1	35.3	28.0	28.1	150.3
Growth	1,064.6	216.0	223.8	208.1	206.4	210.5	1,064.6
Improvement in Service	94.0	12.6	18.5	14.4	12.1	11.2	68.9
Total	**2,448.3**	**496.5**	**510.4**	**477.2**	**443.6**	**455.2**	**2,382.9**

Transmission

In analysing Western Power's proposed transmission CAPEX, we have made the following recommendations:

- reduced asset replacement allowance through changes in allocations for power transformers, switchboard replacement, primary plant and protection ($99.3 million reduction in asset replacement)
- non-acceptance of proposed substation security program as do not consider Western Power has appropriately considered what is critical infrastructure and broad interpretation of National Guidelines relating to terrorism ($59.7 million in regulatory compliance)
- disallowance of two proposed growth projects relating to a new CBD substation at Bennet Street and a second 132 kV Picton-Busselton overhead line ($81.4 million reduction in growth)

Table 4 contains our recommended transmission CAPEX for AA4.

Table 4 Recommended AA4 Transmission CAPEX forecast ($M direct costs at 30 June 2017)

Transmission CAPEX	Proposed AA4 CAPEX	Alternate AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Asset replacement	245.2	20.7	32.8	32.8	27.9	31.7	145.9
Regulatory compliance	155.0	16.9	23.0	19.7	17.3	18.4	95.3
Growth	294.1	43.5	44.0	35.6	48.3	41.5	212.7
Improvement in Service	89.9	11.6	19.7	22.8	20.2	15.6	89.9
Total	**784.2**	**92.6**	**119.6**	**110.7**	**113.7**	**107.2**	**543.9**

Corporate

Table 5 contains our recommended corporate CAPEX for AA4.

Table 5 Recommended corporate CAPEX ($M real direct costs at 30 June 2017)

Corporate	Proposed AA4 CAPEX	Alternate AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Business Support							
Corporate real estate	201.1	23.3	43.2	116.6	9.9	8.1	201.1
Fleet CAPEX	46.7	-	-	-	-	-	-
Fleet lease	30.4	-	-	-	-	-	-
Property, plant & equipment	4.2	0.8	0.8	0.8	0.8	0.8	4.2
Subtotal	*282.4*	*24.2*	*44.1*	*117.4*	*10.7*	*8.9*	*205.3*
IT							
Business driven	149.3	29.9	37.3	28.6	21.5	16.9	134.3
Business infrastructure	55.3	8.5	12.1	17.0	10.8	7.0	55.3
Subtotal	*204.6*	*38.4*	*49.4*	*45.7*	*32.3*	*23.9*	*189.6*
Total	**487.1**	**62.6**	**93.4**	**163.1**	**43.1**	**32.8**	**394.9**

Our key recommendations are:

- The investments in depot redesign refurbishment and consolidation should provide benefits in safety, operational efficiency and security of tenure
- The proposed inclusion of Fleet assets into the regulated asset base (RAB) should be rejected by the ERA as the disadvantages of including them in the RAB appears to outweigh any perceived benefits. We have proposed the disallowance of the proposed CAPEX associated with Fleet.
- We consider the level of investment in customer relationship management (CRM) systems is excessive and the proposal included in the application does not take into account less capital intensive options. We recommend the ERA accepts the proposed CAPEX allowance for CRM upgrade, but also requests Western Power to review its proposed solution and explore low capital solutions to the CRM needs.
- The investment in IT Business Infrastructure is reasonable and we recommend it be accepted.

Our recommended changes to the proposed Corporate CAPEX for AA4 are:

- disallowance of the proposed allowances for Fleet (Fleet CAPEX and Fleet lease) totalling $77 million, due to our rejection of the proposal to move Fleet into the RAB
- removal of a total of $15 million allowance for ICT associated with AMI project from IT Business Driven

vii. Forecast OPEX

We have analysed forecast OPEX using the base-step-trend method, as utilised by Western Power. In doing so, we have:

- reviewed the nominated base year (2016/17) to determine suitability
- identified and assessed proposed step changes and escalation
- adjusted for any proposed changes in individual OPEX programs or projects

We have recommended an alternate OPEX forecast of **$1,734.9 million** for AA4, which is $70 million less than the Western Power proposed total of $1,805 million (or a reduction of 3.9%).

These changes are a result of:

- changes in scale escalation factors due to recent updates in weightings applied to AER benchmarking models for total and partial factor productivity indices (MTFP and MPFP) for distribution and transmission outputs (refer section 7.1.3.1)
- removal of scaled escalation from business support activities
- transmission and distribution SCADA OPEX reduction due to SCADA & Communications CAPEX replacement programs
- distribution metering OPEX reduction as a result of adjusted meter volumes due to recommended changes to AMI

The benchmarking review (refer section 7) concluded that for Western Power:

- in comparison with utilities in the National Electricity Market (NEM), Western Power ranked 9th for distribution utilities and 6th for transmission NSPs
- as a combined electricity network, Western Power ranked 6th (refer section 7.3.3)
- the comparable networks were SA Power Networks (distribution) and ElectraNet (transmission)
- the regulated financial statement for 2016/17 showed a transmission OPEX spend of $105.6 million and distribution of $351.1 million, totalling $456.7 million
- based on the benchmarking rankings for Western Power, the efficient range for total annual OPEX compared to a hypothetical combined SA Power Networks/ElectraNet electricity entity is between $368 million and $379 million (refer section 7.3.3)

With relatively minor scale and labour escalation during AA4, we are of the opinion that the efficient OPEX range nominated in the benchmarking review for 2016/17 can be equally applied to each of the AA4 years for comparison purposes.

From Table 6, the first year of AA4 is forecast to be $375 million, which is at the top end of the efficient range and includes allowances for the final year of the current BTP. For subsequent years in AA4, our alternate annual forecast expenditure is approximately $340 million which is below the lower end of the benchmarked efficient OPEX range.

We consider this supports the Western Power submission (AAI)[1] that they are looking to be more efficient during AA4, recognising that the first impact of many of the BTP initiatives on the total OPEX were realised in

[1] In this report we use 'submission' and Access Arrangement Information (AAI) interchangeably

2016/17. We consider that it is for Western Power to demonstrate that it can operate at the OPEX levels recommended for AA4 to demonstrate efficiency gains it believes the BTP and other initiatives have achieved.

Table 6 Recommended AA4 OPEX forecast ($'000 real at 30 June 2017)

Item	Base Year	AA4 period					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
AA4 base year	317,609	317,609	317,609	317,609	317,609	317,609	1,588,045
Annual reduction		-5,000	-5,000	-5,000	-5,000	-5,000	-25,000
AA4 recurrent OPEX sub-total		*312,609*	*312,609*	*312,609*	*312,609*	*312,609*	*1,563,045*
Escalation - network growth		1,793	3,581	5,746	7,799	9,641	28,560
Efficiency dividend		-3,144	-6,292	-9,455	-12,625	-15,793	-47,310
Non-recurrent OPEX		32,533	1,183	198	-	500	34,414
Expensed indirect costs		39,993	36,676	33,183	39,175	39,256	188,283
Escalation - labour		970	1,810	2,840	4,092	5,387	15,098
Adjustment for maintenance for communication infrastructure from proposed AMI project [2]		-2,207	-2,214	-2,222	-2,231	-2,241	-11,117
Adjustment for SCADA & Communications as trade-off for CAPEX replacement program [3]		-7,265	-7,182	-7,116	-7,232	-7,227	-36,023
Total		**375,282**	**340,170**	**335,782**	**341,586**	**342,132**	**1,734,949**

viii. Service standards

We have assessed Western Power's data in terms of reliability and accuracy, and are satisfied it adheres to the appropriate requirements. Primarily, this refers to the correct classification of excluded events, such as non-reference service customer outages, major event days and the exclusion of the feeder at Kalbarri.

In reviewing Western Power's service standard benchmarks (SSBs) and service standard targets (SSTs), we have taken account of their stated aim to maintain the level of performance achieved in AA3. We commend Western Power on the analytical approach adopted to propose service standard targets and benchmarks; however, our analysis has illustrated that the targets proposed by Western Power have an inherent skew towards a reward payment in the distribution measures, mostly due to the 12-month rolling average dataset used.

We have accepted the benchmarks proposed by Western Power in all cases, except for Rural Long System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) measures.

Table 7 shows our proposed alternate service standard benchmarks and targets.

[2] Refer section 10.2.3.5, includes real escalation and indirect costs

[3] Refer sections 13.5.6.3 and 13.6.6.2, including real escalation and indirect costs

Table 7 Recommended service standard benchmarks and targets

Segment	Measure	Unit	Bonus	Penalty	Western Power SSB	Alternate SSB	Western Power SST	Alternate SST
Distribution	SAIDI – CBD	SAIDI mins	$26,734	$26,734	37.2	37.2	17.8	17.7
	SAIDI – Urban	SAIDI mins	$366,800	$366,800	134.7	134.7	108.7	101.7
	SAIDI – Rural Short	SAIDI mins	$114,374	$114,374	226.3	226.3	190.4	175.8
	SAIDI – Rural Long	SAIDI mins	$41,958	$41,958	902.9	850.9	675.6	643.3
	SAIFI – CBD	SAIFI events	$30,114	$30,114	0.23	0.23	0.14	0.12
	SAIFI – Urban	SAIFI events	$366,867	$366,867	1.33	1.33	1.12	1.06
	SAIFI – Rural Short	SAIFI events	$117,788	$117,788	2.38	2.38	2.01	1.90
	SAIFI – Rural Long	SAIFI events	$65,982	$65,982	5.90	5.30	4.67	4.39
	Call Centre Performance	%	-$43,061	-$9,981	85.3%	85.3%	92.2%	92.1%
Transmission	Circuit Availability	%	-$421,856	-$187,492	97.6%	97.6%	98.5%	98.5%
	Loss of Supply Event Frequency (>0.1 to ≤1 SMI)	Number of events	$42,186	$52,732	27.0	27.0	17.0	17.0
	Loss of Supply Event Frequency (>1 SMI)	Number of events	$140,619	$421,856	4.0	4.0	1.0	1.0
	Average Outage Duration	Minutes	$1,826	$2,909	1,333.0	1,333.0	871.0	871.0

ix. Gain sharing mechanism

We have analysed the GSM as outlined in for AA4. We have concluded that Western Power has complied with the provisions of its access arrangement in the calculation of the GSM amounts for AA4. As determined in AA3, GSM amounts for AA4 must be approved.

Western Power has not demonstrated ongoing continuous improvement in its management of its operating expenditure. Instead there has been a step reduction in expenditure in the final year of the access arrangement that coincides with a significant reduction in staff numbers.

The bias of the achieved savings to the end of AA3 has resulted in a generous benefit to Western Power that is contrary to the objectives of the GSM as set out in the Electricity Networks Access Code 2004 (the Code). The particular matter is the clear benefit related to the timing of the savings rather than them being neutral to the timing. Specifically, the current GSM mechanism did not provide sufficient incentive for Western Power management to capture these efficiencies earlier in AA3. It is noted that the GSM benefit for AA4 is $278 million which largely offsets the reduction in OPEX from AA3 levels of around $60 million per annum or $300 million across AA4.

In our opinion, the ERA should not approve the GSM as set out in Western Power's AA4 submission. As previously indicated, the proposed approach does not meet the objectives of the GSM as set out in the Code. The structure of the mechanism is much less generous to a service provider undertaking a continuous improvement program than one that applies a step improvement late in an access arrangement period. This feature of the mechanism is contrary to the Code provisions which encourage an efficient and sustainable level of expenditure.

It may be appropriate for the ERA, in not approving the proposed GSM provisions, to request Western Power to provide a revised approach and demonstrate how that revised approach meets the objectives set out in the GSM Code provisions.

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1. Introduction

Western Power submitted to the Economic Regulation Authority (the ERA) revisions to its Access Arrangement on October 2, 2017. These revisions are to apply from July 2017 until June 2022. The Electricity Networks Access Code 2004 (the Code) sets out the requirements for Western Power's Access Arrangement including subsequent revisions.

The ERA has commissioned GHD (our/us/we) to undertake a review of the prudency and efficiency of Western Power's proposed capital and operating expenditure for the period July 2017 to June 2022 together with a review of Western Power's governance and expenditure management processes, GSM, service standards and benchmarks and adjustment mechanism.

This report contains GHD's (our) review of Western Power's Access Arrangement Proposal for the fourth Access Arrangement (AA4) period, encompassing financial year 2017/18 to financial year 2022/23. Our report comprises the following sections:

Executive Summary

1. Introduction
2. Method
3. Regulatory framework
4. Governance
5. Asset management
6. Demand forecast
7. Benchmarking
8. NFIT compliance
9. Assessing proposed CAPEX allowances
10. Forecast CAPEX - distribution
11. Forecast CAPEX - transmission
12. Forecast CAPEX - corporate
13. Forecast OPEX
14. Service standards
15. Gain sharing mechanism
16. Summary and conclusions

Values found within this report are rounded, including totals in tables, as such some totals may not match due to rounding.

2. Method

2.1 Quality of data

We have relied upon information provided by Western Power for their AA4 submission, including the main Access Arrangement Information document, related appendices and models. Discussions were held in Perth with Western Power staff between 23 and 26 October 2017, during which there were presentations on particular aspects of the AA4 submission.

Subsequent to these meetings, we requested additional information from Western Power to support our analysis. The response to these Requests for Information (RFIs) was mixed, with some information received being of a high quality in terms of detail, whilst there was some poor timeliness in responding to other RFIs.

In general, the information provided by Western Power to response to our RFIs was reasonable and timely, although there were instances where we received information that had less detail than we could have reasonably expected, particularly with regards to CAPEX projects.

Where data provided was either incomplete or insufficient detail, we have applied conservative assumptions in our analysis.

2.2 Approach

This section outlines the method we have used to undertake our review of the Western Power AA4 regulatory proposal.

2.2.1 Governance

We reviewed the Western Power systems and processes by checking:

- the governance process was applied consistently across Western Power's operations. We used a sampling approach by reviewing the evidence of application of the governance process on certain capital and operating expenditure categories. We assessed whether the project and program governance regime employed by Western Power to manage the works programs was robust and designed to achieve prudent and efficient delivery of work
- the audit system for the governance process is designed to reveal defects and inconsistencies
- Western Power has regard to sound, effective and cost-efficient long-term network development strategies.
- the process by which asset maintenance and renewals (as presented in Western Power's Asset Management Plan) were prioritised is sound and likely to lead to the most cost-effective whole-of-life solution
- the delegations for signing off on CAPEX and renewals decisions reflected good practice, in accordance with the risk levels associated with each investment

2.2.2 Asset management

We conducted a review of Western Power's asset management strategies, including assessment of:

- level of maturity and effective integration of asset management practices within the business

- effectiveness of how data, information and business processes lead to sound decision making to balance, risk, service levels and costs and how well these decisions align with the business objectives and customer needs
- asset strategies for capital renewal and compliance projects and maintenance expenditure requirements which underpin the 10 Year forecast capital and operating budgets and the revenue requirements for the AA4 period.

2.2.3 Demand forecasting

We reviewed the basis of the 2017 demand forecast after reviewing written documentation of:

- forecast preparation methods, processes and quality reviews
- overall network energy, customer numbers and peak demand forecasts
- maximum demand forecast by zone substation
- National Institute of Economic and Industry Research (NIEIR) review of demand forecasts completed in August 2016

From these reviews, we assessed the reasonableness of the demand forecasting approach used by Western Power and the robustness of the forecasts for the AA4 period.

2.2.4 Benchmarking

We have applied similar operating expenditure (OPEX) benchmarking techniques as adopted AER in reviewing the relative efficiencies of electricity utilities in the NEM.

Total and partial factor productivity indexes have been used by the AER to benchmark both distribution and transmission networks. A characteristic of MTFP and PFP indexes is that benchmarks can obtained with a small number of observations in contrast to the large datasets required for the estimation of econometric models. This has made index-based benchmarks more appealing because Australian datasets do not require augmentation with Ontario and New Zealand businesses as has been the case for the econometric based benchmarks. The index approach uses estimated weights to combine multiple outputs (or inputs) into a single output (input) index. The ratio of these indexes (output / input) is then used to compare networks against their peers and themselves over time.

2.2.5 Review of AA4 capital and operating expenditure forecasts

We have investigated the Western Power forecast of CAPEX and OPEX for AA4 and assessed whether the proposed expenditure reflects that a service provider efficiently minimising costs would incur, as required by section 6.4 and section 6.52 of the Access Code.

2.2.5.1 CAPEX

We have adopted a sampling approach to forecast CAPEX analysis, aiming to review a representative cross-section of CAPEX projects. This includes:

- Distribution and transmission projects from each of the CAPEX categories (asset replacement, compliance, growth and improvement in service)
- Projects of various sizes
- Projects that make up 50% of the total CAPEX
- Specific projects/programs of interest, such as Distribution wood pole replacement program

For distribution CAPEX, the following CAPEX projects were selected for analysis:

Asset Replacement	• Pole Management • Conductor Management • Advanced Metering • State Underground Power Program (SUPP)
Compliance	• Pole Management • Bushfire Management • Conductor Management
Growth	• Distribution Capacity Extension • Network Extension
Improvement in Service	• Kalbarri microgrid project

For transmission CAPEX, the following CAPEX projects were selected for analysis:

Asset Replacement	• Power Transformers • Primary Plant • Switchboards
Compliance	• Substation Security • Poles and Towers
Growth (addressing supply, thermal management and voltage)	• T0362344 CBD New Substation • T0362480 CBD Hay/Mulligan Supply Reinforcement • Kemerton 3rd Transformer • NBT – Install Line Reactors • T0357957 PIC-BSN: Const New 132 kV line
Improvement in Service	• SCADA & Communications

For each program/project, we have reviewed the justification for the program/project based on any business case, planning report or any other supporting documentation that may be available and assessed the efficiency or otherwise of the proposed scope of works, and the associated costs. Where possible, we have generated a comparative class 4 estimate to assess the reasonableness of the proposed CAPEX forecast. Based on this review of purpose, volume and estimated costs, we have provided a recommendation for the program/project to be accepted in full/in part or not accepted.

2.2.5.2 OPEX

Western Power has not sought to justify the efficiency its operating expenditure (OPEX) at a cost category level that is using a bottom-up approach to setting expenditure. Instead it has claimed an efficient level of forecast OPEX through application of the base-step-trend (BST) method.

The base-step-trend method is similar to the approach approved by the AER for electricity utilities within the NEM and comprises the following steps:

- select a base year that is considered to be most representative of efficient and recurrent OPEX (direct costs only)
- review of any proposed step changes to ensure these are reasonable and appropriate
- review the application of scale escalation for forecast network growth in assets and/or customers, based on weightings for distribution and transmission outputs from the benchmarking analysis
- check the appropriateness of any proposed efficiency or productivity improvements that are proposed during the access arrangement period.
- examine any proposed non-recurring OPEX allowances for AA4, assessing whether the need has been sufficiently justified and the provision amount reasonable
- assess the amount of expensed indirect costs to be included in the OPEX forecast, using the Western Power Cost Driver Simple method and its consistency with the cost allocation method
- review the proposed labour escalation factor, including the basis such as industry indices and the appropriateness of the material/labour cost split applied
- any adjustments resulting from the assessments of separate distribution and transmission OPEX programs or projects, with consideration of the justified need for the program/project, consideration of any CAPEX/OPEX trade-off that may apply, proposed volume and costs

We will also assess the OPEX forecast we have generated against any nominated efficient ranges from the benchmarking analysis.

2.2.6 Service Standard Benchmarks and Adjustment Mechanism

Western Power measures performance against target in the following areas

- distribution – System Average Interruption Duration Index (SAIDI)/System Average Interruption Frequency Index (SAIFI) for urban and rural feeders
- call centre performance
- transmission - circuit availability, average outage duration, loss of supply events, system minute interruption

For each measure, there are minimum service levels (Service Standard Benchmarks (SSBs)) and Service Standard Targets (SSTs) based on the AA3 SSTs based on the 50th percentile of the historical data for the prior 5 years using 60-point 12-month rolling average datasets, against which the actual annual network and service performance is assessed. Our method for assessing SSBs, SSTs and the adjustment mechanism involved:

- a desk-top review of the ERA Service Standards Access Mechanism and revenue cap determinations for Western Power during the third Access Arrangement (AA3), with a concentration on the performance measures, targets and parameters that were set for it, together with any performance reporting requirements that were set by the ERA

- assessing the adequacy of the systems and procedures used by Western Power in recording faults and outages
- identifying any systemic weakness in these processes or systems
- reviewing the appropriateness of the measures, and SSBs and SSTs proposed by Western Power for the AA4 period, and recommending any changes.

2.2.7 Gain sharing mechanism

We have reviewed whether Western Power's GSM meets the requirements in section 6.21 to 6.28 of the Access Code. We note that the objectives of the GSM are as follows:

- achieving an equitable allocation over time between users and the service provider of innovation and efficiency gains in excess of efficiency and innovation benchmarks
- being objective, transparent, easy to administer and replicable from one access arrangement to the next
- giving the service provider an incentive to reduce costs or otherwise improve productivity in a way this is neutral in its effect on the timing of such initiatives.

3. Regulatory framework

Western Power submitted revisions to its Access Arrangement to the ERA on October 2, 2017. These revisions are to apply from July 2017 until June 2022. The Electricity Networks Access Code 2004 (the Code) sets out the requirements for Western Power's Access Arrangement including subsequent revisions.

This section of the report provides an overall, and generally high level view of the regulatory framework for assessing the efficiency of forecast expenditure, both capital and operating, for Western Power's AA4 proposal.

3.1 Regulatory requirements

The ERA reviews Western Power's submission (Access Arrangement Information (AAI)) in accordance with chapter 4 of the Code. In particular, clause 4.3(c) of the Code sets out the information that must be included in the Access Arrangement information with respect to network costs as follows.

> "*Access Arrangement information must include …*
>
> *(c) if applicable, information detailing and supporting the measurement of the components of approved total costs in the access arrangement*"

Approved total costs in relation to covered services provided by a service provider by means of a covered network for a period of time, are defined as:

> *"(a) the capital related costs determined in accordance with section 6.43 (of the Code); and*
>
> *(b) those non-capital costs which satisfy the test in (as applicable) section 6.40 or 6.41*"

Section 6.43 of the Code requires the capital-related costs to be determined in accordance with sections 6.44 to 6.63 of the Code. Essentially sections 6.44 to 6.50 describe the approach to determining the initial capital base at the start of an access arrangement period. This report does not consider that process.

Section 6.51 allows for inclusion of forecast new facilities investment (capital costs) in the access arrangement for the purposes of determining the target revenue. To include forecast new facilities investment for the purpose of determining the target revenue, the efficiency of those investments must be established.

Equally, the efficiency of forecast non-capital costs must also be established in accordance with sections 6.40 or 6.41 of the Code.

3.2 Regulatory framework for assessing capital expenditure

3.2.1 New Facilities Investment Test

New facilities investment (capital costs) must satisfy the new facilities investment test (NFIT).

Clause 6.52 of the Code states that new facilities investment satisfies the NFIT 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 or providing the covered services forecast to be sold over a reasonable period may require the installation of the new facility with capacity sufficient to meet the forecast sales;

and

(b) one or more of the following conditions is satisfied:

(i) either … the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or …

(ii) the new facility provides a net benefit in the covered network over a reasonable period of time that justifies 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.

3.2.2 Alternative non-network solutions

Non-network costs must meet the requirements of section 6.40 or 6.41 of the Code.

We note that Western Power has included one non-network solution option in its AAI which is the proposal to incorporate a battery and generation at Kalbarri in order to improve reliability of the supply to that town. The cost to augment the network to improve reliability is significantly more than the cost of the proposed alternative option. In reviewing this project, it is considered that Western Power has met the requirements of sections 6.41(a) and 6.41(b)(iii) of the Code. Further information on this project is included in section 10.5.1 of this report.

3.3 Regulatory framework for assessing OPEX

Clause 6.40 of the Code requires that, subject to section 6.41, the non-capital costs component of the approved total costs for a covered network must include only those non-capital costs which would be incurred by a service provider efficiently minimising costs.

Section 6.41 deals with the requirements for non-capital solutions (called *alternative option non-capital costs*):

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 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.

Western Power has not sought to justify the efficiency of its OPEX at a cost category level through a bottom-up approach to setting expenditure. Instead it has claimed an efficient level of forecast OPEX through application of the base-step-trend method.

The base-step-trend method is similar to the approach approved by the AER for electricity utilities within the NEM and comprises the following three steps:

- select a base year that is most representative of efficient, recurrent OPEX
- assess whether additional OPEX is required in order to achieve the OPEX criteria over the forecast period
- apply an annual escalator to take account of the ongoing changes to efficient OPEX over the forecast period. This is estimated by adding expected changes in prices and outputs, and then incorporating a reasonable estimate of changes in productivity

3.4 Service Standards Access Mechanism

In accordance with the provisions of sections 13 and 14 of its electricity distribution and transmission licences, Western Power is required to maintain and report on performance standards as requested by the ERA, and as required by the Access Code.

Chapter 11.1 of the Access Code requires Western Power to "*… 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.*"

The Access Code defines the Western Power network as that part of the South West Interconnected Network (SWIN) that is owned by the Electricity Network Corporation (trading as Western Power).

The measures against which Western Power has previously reported performance are comparable to the parameters and sub-parameters under the AER Service Target Performance Incentive Schemes (STPISs) for electricity distribution and transmission. As the Access Code states that the existing service standard benchmarks (that is, the minimum service levels that are to be achieved) apply only to reference services, connections that are currently classified as non-reference service customers were excluded from the performance reporting to the ERA.

The Service Standard Adjustment Mechanism (SSAM) is the scheme by which the ERA assesses an annual financial reward or penalty for each of the measures. For each of these service standard benchmarks, a Service Standard Target (SST) was generated based on historic performance from the previous 5-year period. The annual result for each measure is calculated based on the difference between the actual performance result and the SST, with the penalty capped at the SSB.

4. Governance

4.1 Introduction

Strong governance is a key to success for all organisations. In a regulated environment, where decisions and performance is reviewed by government agencies, governance is vital to ensure that valid decisions are made and operations are run efficiently and in accordance with the code and regulation.

In this section we:

- assess Western Power's governance policies, processes and procedures
- review how governance is applied to both CAPEX and OPEX expenditure
- discuss whether governance has been applied effectively during the AA3 period and the AA4 period
- assess whether governance issues raised during the AA3 review have been adequately addressed
- provide an overall assessment of Western Power's governance processes

4.2 Governance principles

Governance is a term that is used broadly; in the context of this review and Western Power's AA4 submission we have relied upon the definition of governance used by the Australian Institute of Directors. The institute uses the following description of Governance:

"Governance is a broad-ranging term which, amongst other things, encompasses the rules, relationships, policies, systems and processes whereby authority within organisations is exercised and maintained"

For Western Power this will refer to the policies, processes and procedures that are used to plan, prioritise, manage and measure their capital programs, allocation of capital, on-going operations, operating expenditure and the budgets for both CAPEX and OPEX.

Key principles of effective governance include:

- Goals - clearly enunciated goals for the organisation and or the specific section of the organisation to which the governance policies, procedures and procedures are being applied
- Accountability - clarity on individuals' and groups' roles in the governance process, this is especially important for the person who is accountable for the execution and performance of a specific task
- Processes - well defined and efficient processes that are known to people who need to apply them. Key processes should have a single accountable person allocated to ensure the process is delivering the desired outcomes
- Measurement - consistent measurement of governance performance with clear consequences for non-compliance or non-performance

Governance in the context of Western Power's AA4 submission is very important as it provides confidence that the organisation has the right policies, processes and procedures in place to:

- CAPEX
    - o identify the areas that require investment to maintain and augment the network to meet the demands of their customers

- prioritise capital investments – focusing their limited capital on the highest return projects
  - determine the most cost effective solution for priority capital investments, including the creation and examination of viable alternatives
  - ensure that all projects are approved by executives with the right level of authority
  - manage project execution against agreed outcomes
  - measure benefits against original business case and identified need
- OPEX
  - determine what operational expenditure is required to meet required service levels as efficiently as possible
  - allocate budgets to managers accurately and in a timely manner
  - measure operational execution performance and corresponding spend against budgets
  - identify quickly areas of underperformance and provide process for resolution
  - determine areas where opportunities are available to enhance performance and or reduce costs.

In our review of Western Power's governance policies, processes and procedures and their application in current and future projects and operations we have sought to identify whether the ERA can rely on the application of governance to drive effective and efficient decision making and operational performance.

Our assessment has also set-out to determine whether the governance issues raised in the review of the previous Western Power AAI (submission) have been addressed over the AA3 period or planned to be addressed during the AA4 period as set out in the AA4 AAI. The governance framework has been updated substantially since the last submission, however it is important to document whether previous concerns have been addressed.

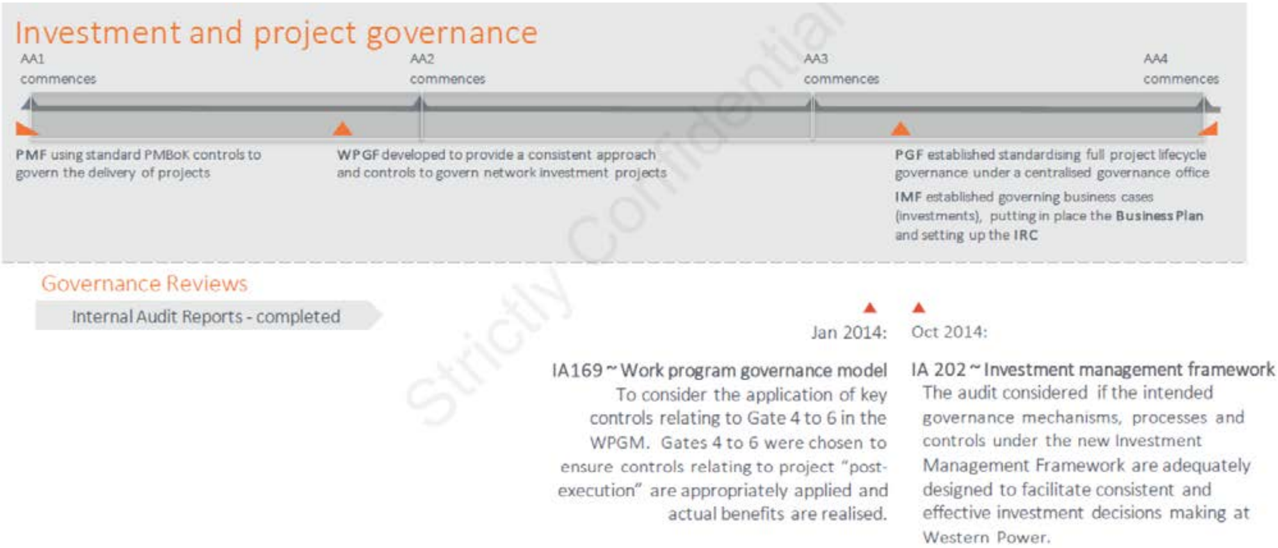
The key concerns raised in the previous technical review were:

1. Little evidence that defined governance processes were actually embedded in the governance of individual projects
2. In the design phase there was limited creation of alternative options to identified issues
3. Western Power lacked an effective quantitative risk assessment tool
4. Management of asset condition data was not strong

4.3 Investment Governance Framework

In October 2014, Western Power introduced a new governance framework that is documented in an attachment entitled *Attachment 7.2 – Investment Governance Framework* to the AA4 AAI.

Figure 1 Governance framework timeline[4]



The framework aims to set-out how Western Power will manage its capital investment program. Starting with the identification of investment requirements or opportunities through to the actual implementation of the project and the realisation of benefits.

The objective in creating the framework is to *"… ensure that Western Power's investments create value for the organisation"*[5].

It is important to note the scope of the framework. It covers all capital investments with the exception of inventory purchases not directly linked to an investment, one-off non-recurring operational expenses and investments in the creation of a "step-change" in performance. It does not cover recurring operating expenditure and financial investments. We have not sighted an equivalent governance document for recurrent operational expenditure.

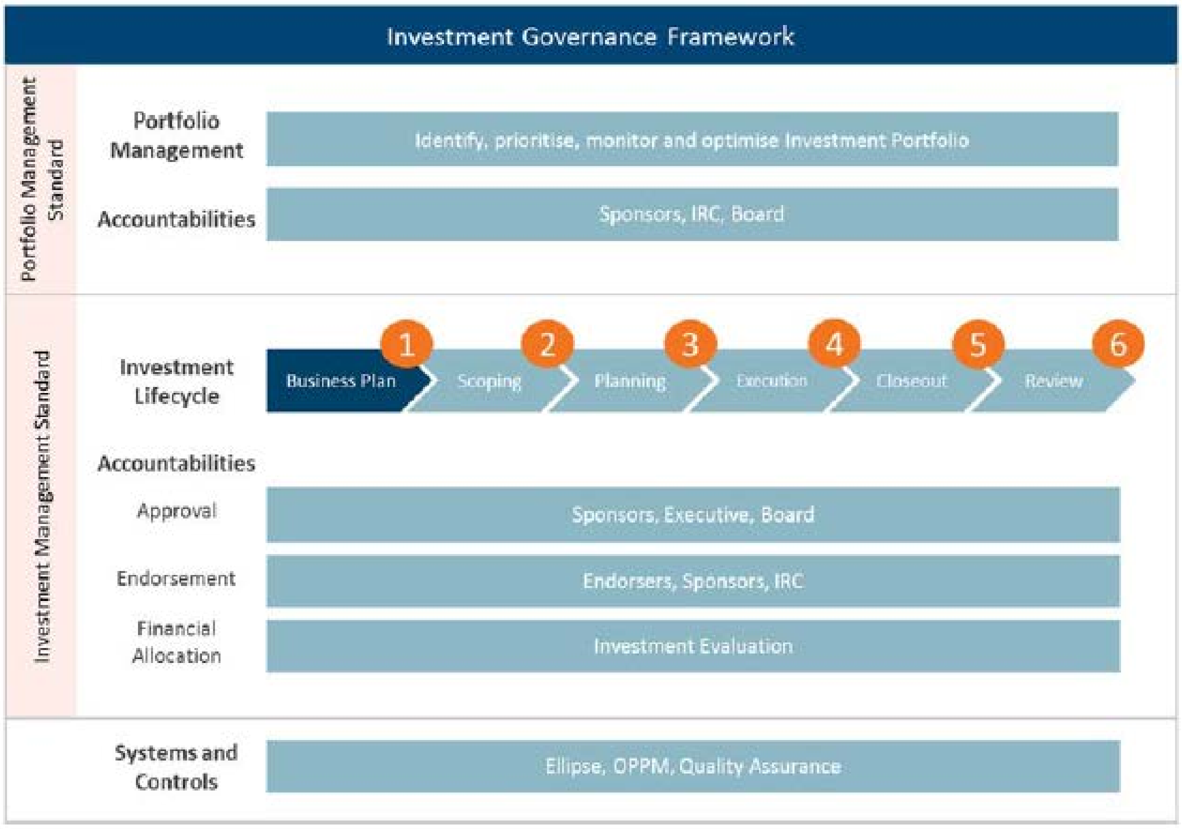
The Investment Governance Framework must be followed for any investment related decisions, although the framework's mandatory requirements are scalable across the various investment profiles.

Figure 2 shows the overall governance framework.

[4] Western Power, *Timeline of Governance Frameworks*, 23 October 2017, p. 2

[5] Western Power, *Investment Governance Framework*, 10 August 2017, p. 2

Figure 2 Overall Governance Framework[6]



This diagram illustrates how investments being undertaking or proposed are aligned with the overall strategy of the organisation. The two key working areas within the framework are the investment portfolio which is managed through the Portfolio Management Standard and the individual investments which are covered by the Investment Management Standard.

4.3.1 Portfolio Management Standard

This document is designed to *"… translate the Board approved Investment Management Policy and Investment Governance Framework into practical requirements and accountabilities relevant to managing Investment Portfolios.*"

Western Power has created a Corporate Portfolio of projects that represents the organisation's entire investment opportunity set. It is the manifestation of the corporate planning process and reflects the core investment the organisation will be making over the AA4 period. It is a dynamic portfolio of projects that is continually updated through the corporate planning process and the actual execution of investment projects (refer Figure 4 for the Corporate Planning process).

The overall portfolio is then broken down into 24 discrete asset type portfolios (detailed below) which are assigned specific objectives and target metrics. These portfolios are managed by accountable functions who create strategy documents that guide the individual Investment Portfolios future investment plans. The functional strategies are informed in a top down direction from corporate strategy and functional strategies and by information derived from asset performance management and applying Western Power's Network Risk Management Tool (NRMT); the supporting asset and risk management framework and the tools

[6] Western Power, *Attachment 7.2 Investment Governance Framework*, p. 10

Western Power applies are assessed in Section 4.4). The corporate planning process is detailed below in Figure 4.

Figure 3 Corporate Portfolio and Functional Responsibility[7]

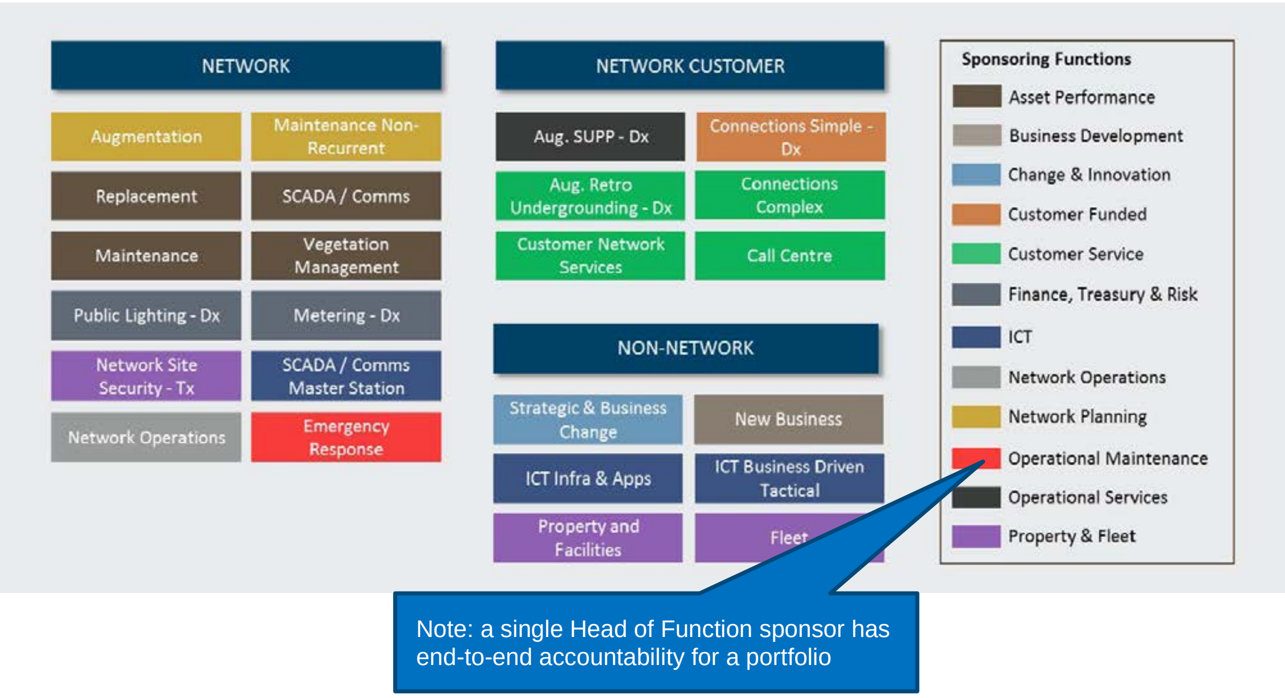
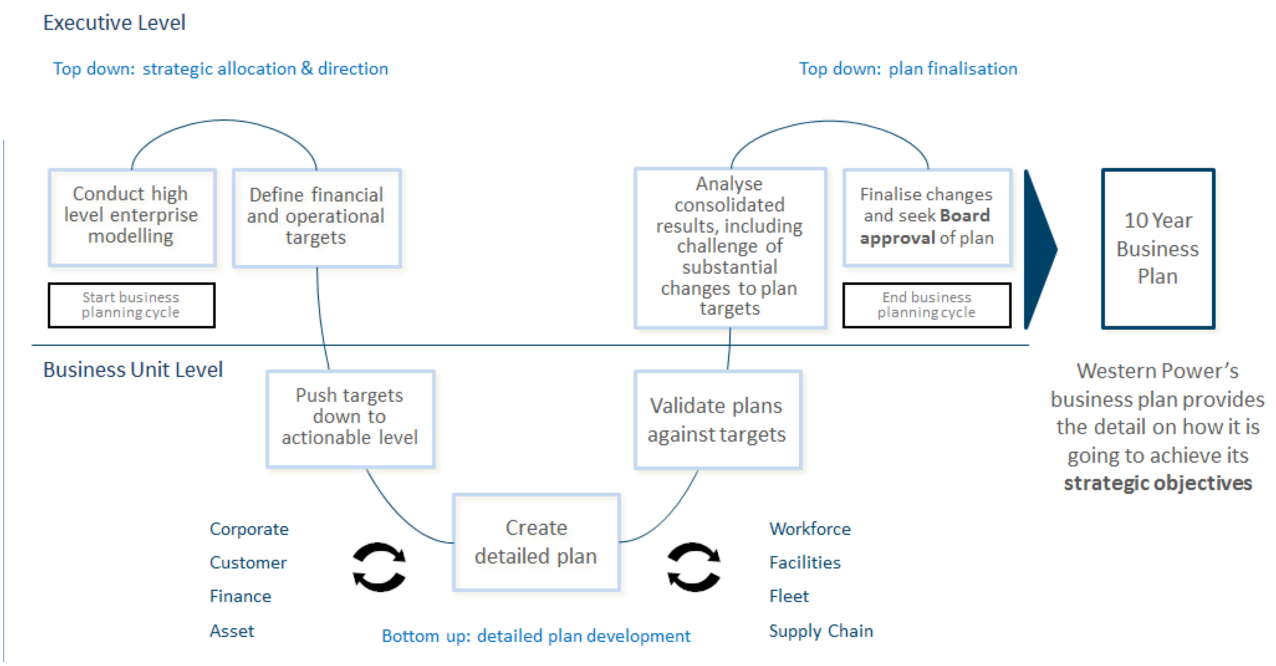


Figure 4 Corporate planning process[8]



[7] Western Power, AA4 Presentations: Investment Governance Framework, 23 October 2017, p. 6

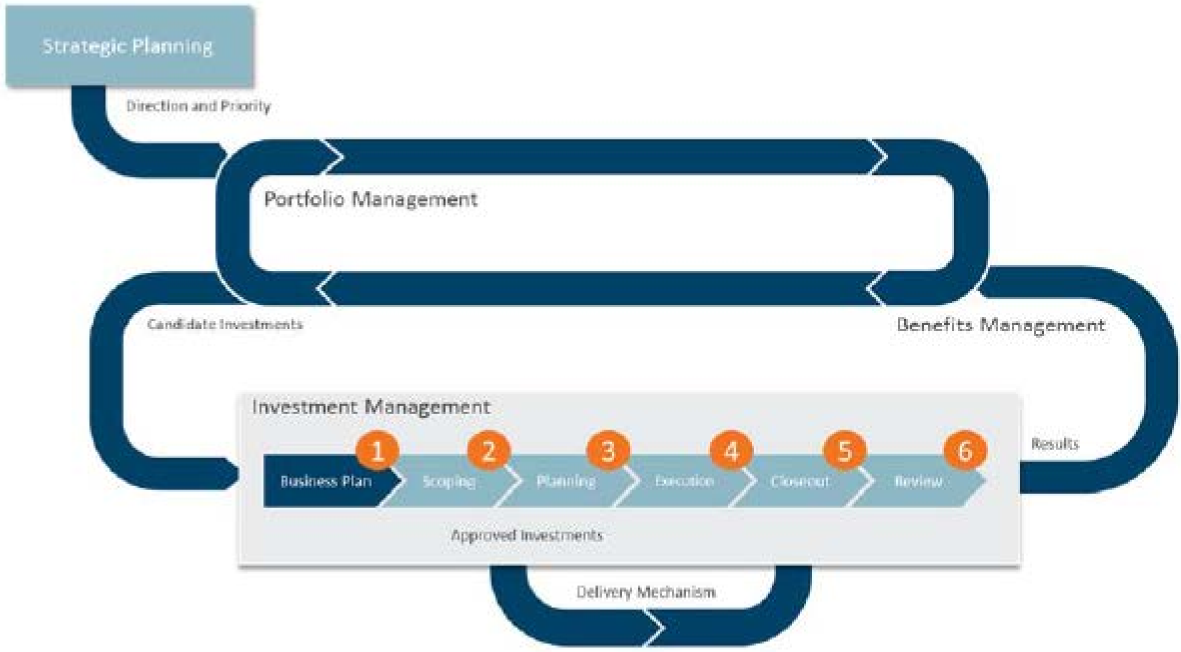
[8] Ibid., p. 7

The portfolios are constantly updated and are not static databases. Through-out the year sponsors manage their portfolios through a lifecycle of:

1. Identifying objectives
2. Constructing the portfolio
3. On-going assessment
4. Rebalancing

From a governance and investment efficiency standpoint this is a vital process to ensure that each portfolio has identified and prioritised the right projects and is maintaining and improving Western Power's asset base in an efficient and effective manner. Successful management of the portfolios requires clear input from the corporate strategy and up to date and accurate information on the performance of the assets within the portfolio. The individual projects within the portfolio are the interface with the investment management process. Feedback from this process will directly inform whether progress is being made on projects in the portfolio, what projects should be in the portfolio and their relative prioritisation.

Figure 5 Interface between portfolio management process and investment management[9]



Applying the core principals of governance discussed above it is our assessment that the portfolio management standard provides a good basis for the consistent selection of value adding projects for Western Power to execute. There is a strong linkage between the corporate strategy, the development of investment portfolios and ultimately the selection of investments to be implemented. However, there are some key areas that require close management for the governance process to be effective over the AA4 period:

[9] Western Power, *Portfolio Management Standard*, p. 16

- The effective matching of top down strategy and bottom up driven investment requirements. There needs to be a genuine two way conversation between those that allocate capital and the sponsors of individual asset classes in the creation of investment plans. If top down capital allocation becomes overly dominant in the creation of investment plans the capital required to maintain asset reliability and operational performance may not be made available. This could lead to higher operational risks and poorer service outcomes. We do not have evidence that this imbalance has occurred, however it is an inherent risk with top-down driven capital allocation approaches.
- The overall process is complex and potentially unwieldy, particularly with respect to lower value investments. This places a burden on the organisation and has a tendency to restrict the ability of the organisation to act quickly. A balance needs to be found that provides the right level of robustness to investment opportunity identification and scrutiny on investment decisions, with the amount of effort and expense that goes into implementing the require process. During presentation of its AAI, Western Power did state that they were developing a "light" version for smaller projects. This should reduce the potential administrative burden on this type of project.
- Asset condition and performance data – without accurate and timely asset condition performance data the identification of issues and or opportunities and their prioritisation against other investment opportunities would be impacted.
- NRMT – The outputs from this tools are very influential in determining how projects are prioritised. Close monitoring on the accuracy of this tool and how it is being applied is very important to ensure the right risk weightings are being applied to assets and projects. The tool is relatively new its accuracy of forecasting risk outcomes should be continued to be evaluated throughout the next regulatory period.
- Regular and consistent review of the portfolios and the interdependencies across the portfolios. If the portfolios are not actively managed by sponsors the investment pipeline will become stale and out of date relatively rapidly and impact overall investment efficiency and effectiveness. A substantial proportion of the work for effectively managing these portfolios rests with functional sponsors, on top of their other duties. Sufficient resources need to be allocated to ensure sponsors can manage their portfolios appropriately.

Given the need for capital efficiency in meeting customer needs, ensuring that only the highest value projects (from a financial, risk and safety perspective) are being presented and executed is very important for Western Power to achieve its goals.

In order to test whether the portfolio management standard is operating effectively from a governance perspective we have reviewed three asset management strategies:

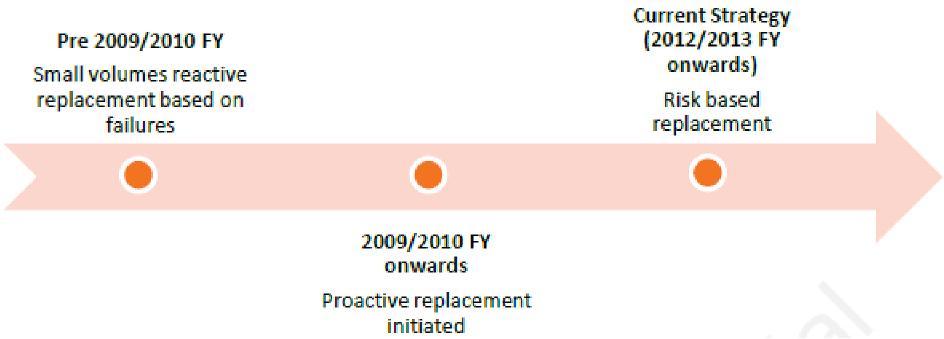
1. Transmission Lines Asset Management Strategy (41008510)
2. Power Transformer Asset Management Strategy (33141537)
3. Asset Management Strategy - Distribution Conductors (41011130)

All three documents comprehensively set out the strategy for each asset type and highlight a risk based approach to capital investments and operations. The documents also demonstrate the journey that Western Power has been on to transform from a reactive organisation to a more proactive and risk based organisation. Western Power advised during presentations to us that it ranks investment projects on a basis of risk reduction per dollar spent. We consider the use of risk reduction per dollar spent as an appropriate criteria, along with other criteria, in ranking capital projects in that it will support the drive to cost effective improvements in overall network performance and reliability.

In all documents the use of risk to determine which assets to replace and how to treat assets was clearly demonstrated. The use of a risk based approach has enabled the asset managers to identify different methods of cost effectively managing the asset base while not raising the overall risk profile.

While we consider the risk reduction to dollar spent ratio represents a good approach to rank network asset investments, it is recommended that Western Power considers adopting a multi criteria approach to capital prioritisation, with risk reduction per dollar spent being one of the weighted criteria in the multi-criteria analysis, to rank expenditure over the entire capital investment portfolio. These methodologies are being adopted by other transmission and distribution utilities. The multi-criteria analysis method provides a more rigorous capital prioritisation of expenditure over the entire capital investment portfolio, than a method relying on a single criterion, enabling meaningful and consistent comparison of investment requests within segments and between segments. The optimisation processes can also assist in deferring capital expenditure while maintaining service standard targets (SSTs) and other business performance objectives.

Figure 6 Example of changes in Western Power's asset management strategy[10]



The asset strategy for distribution conductors, for example, has changed from prior to 2010 where a reactive based approach to conductor failures was adopted, to a proactive replacement strategy from 2010 to 2015, to a current strategy of risk based replacement. A risk based replacement strategy can be adopted given the greater knowledge and data that Western Power has about the failure mechanisms within different types of conductors and environment condition risks than it previously had. Figure 6 demonstrates the transition to the current risk based replacement approach which we consider will achieve significant reduction in capital replacement expenditure in the AA4 period compared to the AA3 period.

However, our review of the Power Transformer Asset Management Strategy has highlighted a key risk with applying this approach to identifying and prioritising capital investment. This asset class has a substantial number of assets which are rated as poor or bad which triggers an asset replacement process. It is not clear from our review that the corporate strategy has the flexibility to react to the reality of the asset base. For example, this asset class could, given its risk profile, require more investment than originally envisaged. This situation is manageable; however, it does require that the Investment Evaluation Team and the Asset Class Sponsor working closely together so that corporate strategies and objectives don't override the requirements of the asset base. It is also important that Western Power's asset condition data is robust. From our analysis of failure rate risk, we note that the calculated failure rate risk is 0.52% whereas the actual failure rate is 0.29%. This suggests that, on average, the network asset condition is superior to what Western Power assess it to be. Our assessment in this case is focused on whether the governance process has been

[10] Western Power, *Asset Management Strategy - Distribution Conductors*, p. 23

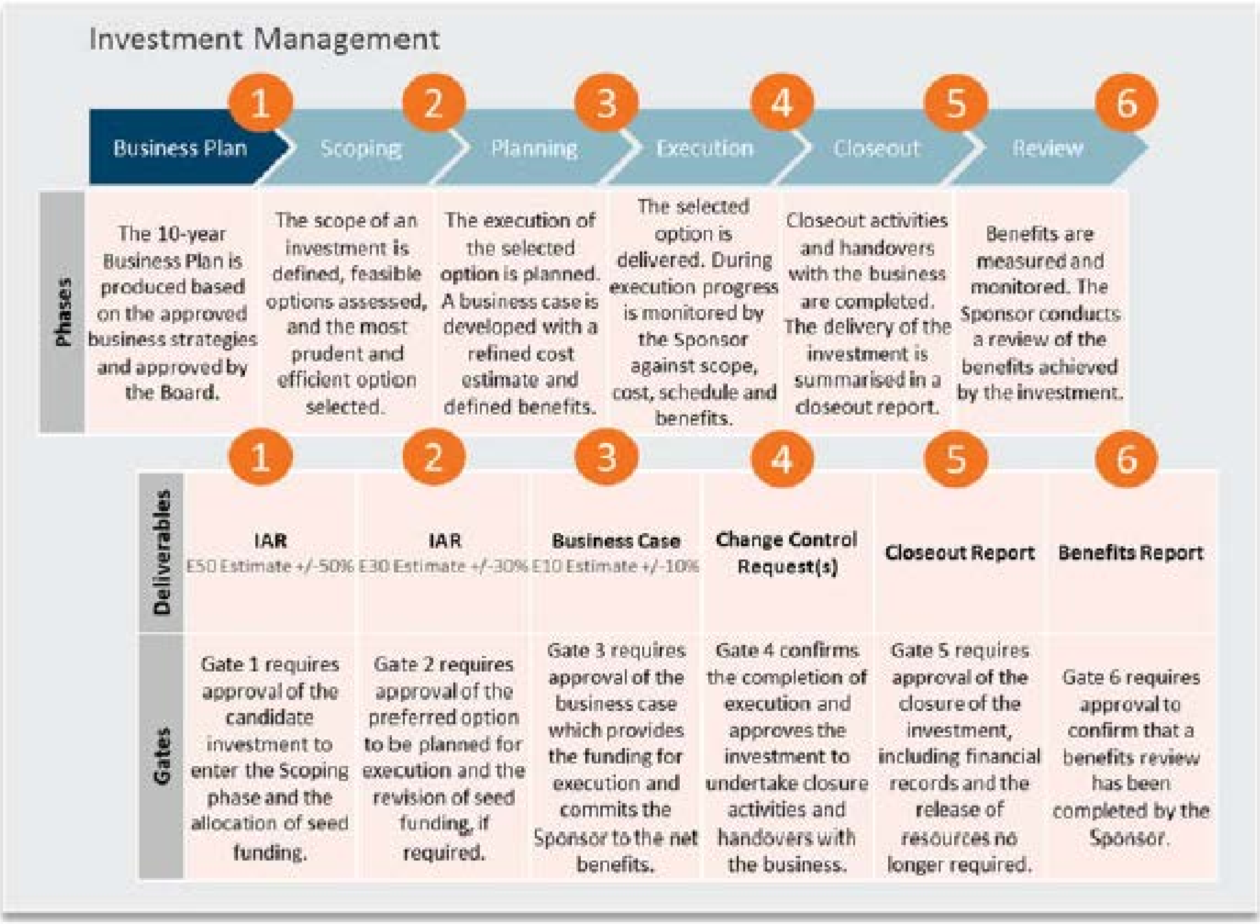
applied as described. We have separately reviewed asset management strategies in other areas and this is detailed in Section 5.

4.3.2 Investment Management Standard

This document sets out to the governance process for managing a single investment project from start to finish. This process works in tandem with the Portfolio Management Standard described above.

The investment lifecycle, detailed below, is a six phase process with six control gates throughout the process. The process is designed to monitor the progress of an individual project through the life-cycle to ensure that it meets its objectives. Each gate is mandatory and approvals must be in place before the investment can progress to the next phase.

Figure 7 Investment management lifecycle[11]



The standard sets out clearly the purpose of each gate, the requirements for approval and the role for each participant in the stage, including the Regulation and Investment Management function which administers the overall function.

The governance being applied in each process is clear and follows good standard practice for the management of projects throughout the project life-cycle. If the process is applied appropriately to investment projects then these processes should deliver expected project outcomes on a regular basis and

[11] Western Power, Investment Management Standard, p. 4

identify issues arising during the execution of a project and thereby allow appropriate mitigation steps to be taken.

4.3.2.1 Business Case Guideline

To support the investment management standard, Western Power has produced a business case guideline that is compulsory for project sponsors to prepare to pass Gate 3. The document and supporting business case template clearly outline what is required to be included in the document. This includes important investment governance aspects, such as:

- Options analysis
- Risk analysis
- Value analysis

Adherence to the business case guideline should enhance the confidence the ERA has in Western Power's investment decisions.

In our review of the guideline we did not identify advice on community engagement. Given the outcomes of the "Special Inquiry into Government Projects and Programs" we suggest that Western Power also incorporate specific guidance on the importance of and how to conduct community engagement.

To test whether Western Power has been applying the processes and policies incorporated into these documents we reviewed six business cases:

1. T0410271 West Kalgoorlie SVC Replacement
2. T0425186 PTA FAL Traction Supply - 2019
3. 40428298 CPO - Distribution Overhead Corridor FY1718
4. T0411100, N0411166 - OP Replace Indoor SWBD
5. N0401433 EPCC refresh DMS Hardware Stage 2
6. N0408486 Dedicated Metal Streetlight Poles

The business cases varied in age and size; however, they all followed the same format. In all cases it was clear that all important approval governance measures were followed, with the relevant levels of authority providing sign-off, including at board level where required. In three of the four cases the option analysis was comprehensive with viable options considered in depth. Examination of alternatives is a vital part of business case preparation as looking in depth at options provides a measure of contestability to expected solutions. Although we are relying on the business case documentation it would appear that innovative ideas where considered and in a couple of cases selected that enabled far lower cost solutions to be identified and recommended than originally envisaged.

Risk was examined in detail in all business cases. However only in *CPO – Distribution Overhead Corridor FY17/18* was the NRMT clearly used to influence the decision making process. In this case, Western Power was able to clearly articulate the risk impact on the network of the alternative options.

While business cases are the most important document in the investment management lifecycle, for the governance process to work as described it is important that the other gates are applied as described and, documents prepared and approved as necessary. To test whether the other gates and documents were applied, we looked at the following documents across the lifecycle. Given that the framework has not been in place for an extended period of time we were not able to test each stage to the same extent. Table 8 shows the documents tested.

Table 8 Investment lifecycle documentation reviewed

ERA Asset Segment	Project Number	Project	IGF Progress						IGF DMs					
			Gate 1 Business Plan	Gate 2 Scoping	Gate 3 Planning	Gate 4 Execution	Gate 5 Closeout	Gate 6 Review	Gate 1 IAR	Gate 2 IAR	Gate 3 Business Case	Gate 4 CCR	Gate 5 Closeout Report	Gate 6 Benefits Report
Transmission	T0425186	PTA FAL: Tx Traction Supply			x				43726957 (SIF) 34222110 (WPR)	43726957 (SIF) 34222110 (WPR) 43678823 (IEM) 34233922 (Scoping Estimate) 42909492 (Planning Estimate)	NA			
Transmission	T041110	OP: Replace Indoor SWBD: AA3				x			34393016 (SIF) 34332393 (WPR) 34247586 (IBP) 34358848 / 34391358 (IEM Parts 1 & 2)	34393016 (SIF) 34332393 (WPR) 43098901 (Planning IEM) 34372175 / 34391355 (Scoping Estimate Parts 1 & 2)	41306714 (BC) 41393523 (PMP) 41540410 (Planning Estimate)	NA		

ERA Asset Segment	Project Number	Project	IGF Progress						IGF DMs					
			Gate 1 Business Plan	Gate 2 Scoping	Gate 3 Planning	Gate 4 Execution	Gate 5 Closeout	Gate 6 Review	Gate 1 IAR	Gate 2 IAR	Gate 3 Business Case	Gate 4 CCR	Gate 5 Closeout Report	Gate 6 Benefits Report
Transmission	T0362480	CBD: Hay/Milligan Supply Reinforcement			x				31645957 (SIF) 10389672 (WPR)	31645957 (SIF) 10389672 (WPR) 12745875 (Scoping IEM) 41744174 (Planning IEM) 12745859 (Scoping Estimate) 40497823 (Planning Estimate)	NA			
Transmission	T0375137	MU: Replace Failed Tx T1				x				10172464 (Change Control 1) 10825384 (Change Control 2) 12105168 (Change Control 3) 12786955 (Change Control 4)	10195588 (BC) 10848064 (PMP)	40923487 (Closeout report)		

ERA Asset Segment	Project Number	Project	IGF Progress						IGF DMs					
			Gate 1 Business Plan	Gate 2 Scoping	Gate 3 Planning	Gate 4 Execution	Gate 5 Closeout	Gate 6 Review	Gate 1 IAR	Gate 2 IAR	Gate 3 Business Case	Gate 4 CCR	Gate 5 Closeout Report	Gate 6 Benefits Report
Distribution	N0411166	OP: Replace Feeder Exit Cable: AA3			x	x			34393016 (SIF) 34247586 (IBP)	34332393 (WPR) 34358848, 34391358 (Scoping IEM) 3432175 (Scoping Phase Estimate Part 1)	41306714 (BC) 41830091 (Planning Estimate) 41403863 (PMP) 43098901 (Planning IEM)	NA		
Distribution	N0408486	Replace Dedicated Metal Streetlight Poles 15/16					x		11878376 (DSMP Management Strategy) 12831473 (Unit Rate for Estimate)	12906941 (WPR) 12783646 (IEM)	12755489 (BC) 13153050 (PMP)			
Distribution	N0401433	EPCC: Refresh DMS Hardware: STG2				x				12196483 (WPR) 12196489 (IEM) 13320896 (Planning Phase Estimate)	12198079 (BC) 12996781 (PMP)	42883712 (CCR)		

Legend SIF	Strategic Investment Framework	WPR	Works Planning Report	BC	Business Case
IBP	Issues Briefing Paper	IEM	Investment Evaluation Model	PMP	Project Management Plan

From our examination of the documentation provided we conclude that Western Power has been following the process described in the investment management standard. However, based on what we observed, we note the following:

- On two out of four occasions the Investment Evaluation Models (IEMs) were run with only one option when the business case describes more than one option in detail. One of the purposes of the model is to compare options and test their sensitivity. IEMs should be run with all options to allow for an effective and consistent comparison of the financial impact of each option. If information is not available, it would preferred to wait until information is available than run the analysis for only one option.
- We reviewed four monthly project progress reports for the following projects:
  - N0401433 East Perth control centre
  - N0411166OP Replace feeder exit cable
  - T0354029MSS Install 3rd Tx
  - T0411100 OP replace indoor switch board
- While the reports used a standard format, commentary on the progress of the project was generally scant. Issues impacting progress were raised; however, plans or activities to mitigate the impact of the issues were not described. If these reports are representative of typical reports presented each month to management there is a likelihood that issues that could impact the successful execution of the project could be missed or inadequately addressed.
- The quality of reporting is also essential to enabling effective contract management. It is therefore important that Western Power focus on effective project reporting as a precursor to managing vendor delivery of goods and services.
- Only one project from the group we had selected had been finished - T0375137 Muja Replace Failed Tx T1. At the time of our review, this project had not been finalised within the governance process and the close-out report had not been completed, and was therefore not available.

4.3.3 Roles and responsibilities across Governance framework

A core aspect of good governance is clear accountability for specific activities. Clear accountability combined with detailed explanations of responsibilities and key outputs enhances the likelihood that the required actions will be completed to the desired standard. The other side of the accountability coin is that the accountable person has to be held to account for actually delivering what is requested of them. In the context of the Investment Governance Framework it is imperative that the person or group reviewing the output of the accountable party actually ensures that all outputs meet the documented standards or guidelines.

In the Investment Governance Standard roles and responsibilities have been clearly outlined as part of the documents. Roles and responsibilities have been subsequently outlined in the supporting Portfolio Management Standard and Investment Management Standard.

In our review of actual documentation such as business cases and asset strategies based on the approvals made to the respective documents we consider that the roles and responsibilities as outlined have been adhered to.

Figure 8 Roles and responsibilities for investment governance[12]

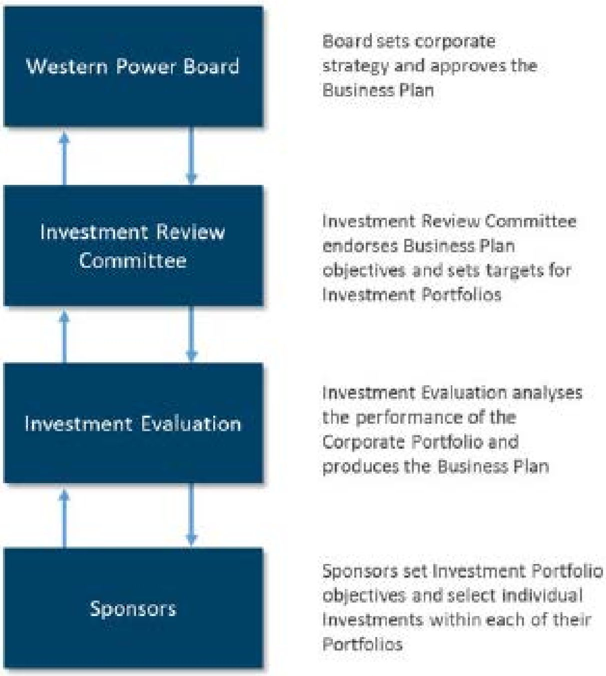


Figure 2.1: Roles and responsibilities for Investment governance

4.4 Asset Management

The AMF and associated processes are an integral part of the effective governance of capital investment and operating costs. Identification of network integrity risks start with understanding the condition of the asset base. It is therefore vital for the efficient management of capital investment and operating costs, for Western Power to accurately maintain and leverage a strong asset management system.

The key governance aspects of the AMF are:

- whether the framework is robust and likely to provide Western Power management with the asset information they need to effectively manage their network.
- whether the framework is being applied effectively so that the benefits of the framework are being derived by the organisation

The framework defines the relationship between overall asset management strategy and objectives and network planning, performance and risk.

The two key inputs into the framework are Performance Management and Risk Management. The major outputs are the individual asset class strategies, the individual projects that preserve and improve the asset base and the operational strategy that maintains and monitors the existing asset base.

The strategy process is informed by the Renewal and Maintenance Requirements Analysis Standard which details five key steps.

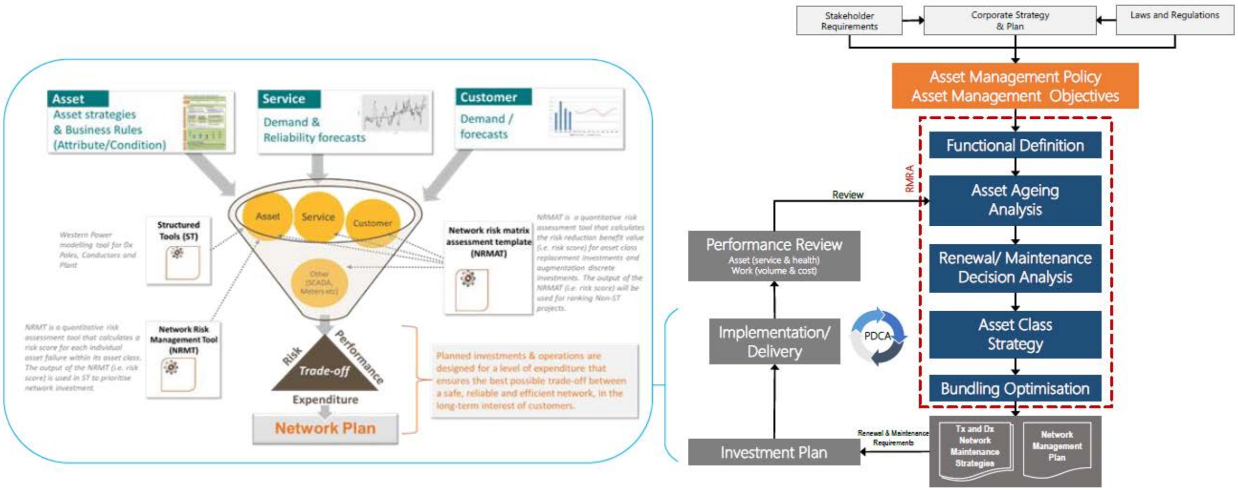
[12] *Investment Governance Framework*, p. 4

1. Functional definition
2. Asset ageing analysis
3. Renewal/ maintenance decision analysis
4. Asset class strategy
5. Bundling optimisation

In the review of the asset strategies supplied by Western Power these steps were clearly documented.

The planning process is outlined below and explains how the 10 year reference case is transformed into the implementation plan for renewal and maintenance of existing assets via the Network Management Plan (NMP) and corresponding plan for capacity expansion the Network Development Plan (NDP).

Figure 9 Western Power planning process



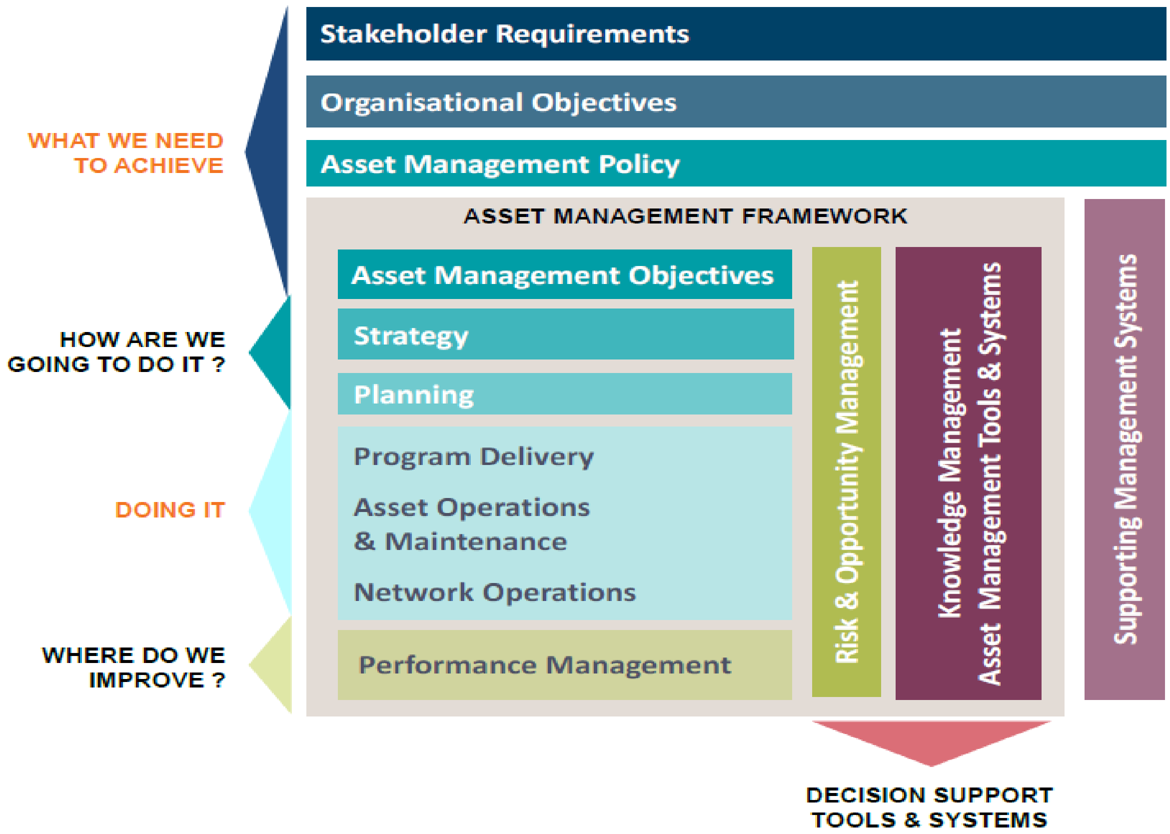
Two key inputs that help drive the identification of the highest value solutions to maintaining and improving the network are:

1. Performance management
2. Risk management.

Performance management is guided by the Asset Performance Management Standard which establishes the link between the performance of an asset, or group of assets and the defined asset objective. The key performance reports, such as Asset Information Packs and Quarterly Performance Reports are produced in accordance with the standard. In addition, the survival analysis is used to calculate MRLs for the various asset classes.

Without good performance information it is difficult to make informed investment decisions about the different asset classes. From our analysis of the asset strategies we mentioned above, we consider that Western Power has been able to create suitable asset performance data to enable them to identify asset integrity issues with the network. The approach used to collate data varies by asset class. It should be noted that investments in field based data collection devices has enabled faster updating of records and better documentation of asset conditions than was the case at the time of the AA3 AAI.

Figure 10 Western Power Asset Management Framework[13]



Risk management plays a vital and growing role in the identification and prioritisation of investment projects. During the AA3 period Western Power has made a significant investment in the development of its risk management capabilities and now uses risk management techniques extensively in its investment decision making process. Decisions that are guided by risk include; strategy development, planning and delivery.

Western Power has written a Network Risk Management Standard that sets-out how the organisation approaches risk management. The principals used in Western Power's risk management processes are typical for infrastructure companies and do not require specific comment. The asset management strategy documents reviewed highlighted how risk assessments were used to inform asset strategy and decision making.

The element of Western Power's risk management process that is of most interest from this submission's perspective is the creation of its NRMT. This quantitative risk tool has been used to model the risk of asset failure to customers, workforce and the community. Western Power has created models for the following asset classes:

[13] Western Power, *Network Management Plan*, p. 7

Plant	Conductors	Poles and Towers
	Dx	
Dx DOFs	Dx Conductor - Horizontal Clashing	Dx Streetlight Metal Poles
Dx Ground Mounted Transformers	Dx Conductor - Failure	Dx Wood Poles
Dx Pole Mounted Transformers	Dx Conductor - Ground Clearance	Dx Stay Systems
Dx Pillars	Dx Conductor - Vertical Clashing	Dx HV Cross Arms
Dx Pole Top Switches	Dx Customer Service OH Attachments	Dx LV Cross Arms
Dx Reclosers and Load Break Switches	Dx Insulators	
Dx RMUs		
Dx SAs		
Dx Sectionalisers		
Dx Voltage Regulators		
	Tx	
Tx Circuit Breakers	Tx Conductor Failure	
Tx Disconnectors and Earth Switches		
Tx Substation Earthing		
Tx Instrument Transformers		
Tx Power Transformers		
Tx Protection Relays		
Tx Reactive Plant		
Tx Boundary Substation Security		

The NRMT creates a risk score in dollars at an individual asset level, using the formula shown below.

The assessment of the likelihood of failure is a mixture of engineering judgement and regression models, based on asset type and available data. Consequence is modelled from asset performance analysis. Finally the cost of consequence puts a dollar value on the different types and severity levels of incidents occurring.

This tool is important as it enables a network view of risk and can therefore be used to prioritise and plan capital investments. It has been used to assist in the investment planning Western Power has used to develop its submission for the AA4 period, particularly for its larger volumetric programs. An example of its application can be seen in NFIT Business Case *CPO - Distribution Overhead Corridor FY1718 40428298*. In this business case, the options were assessed using this model and the option chosen had the lowest NRMT score. It has also been used to back the deferral of replacement of assets and could be used to assist with the selection of different maintenance approaches.

If the NRMT model works as designed then it could be a very important tool to enable Western Power to manage their network in a safe, reliable and cost effective manner. At this stage it is too early to assess the validity of the tool, however as Western Power's reliance on the tool increases over the AA4 period it will be important to assess its accuracy in forecasting risk appropriately.

4.5 OPEX governance

Governance of expenditure on operations, particularly for areas with material spend, is as important as ensuring that capital investments are well controlled and focused on providing value for money. In most large companies with substantial operations, governance of operational spend is managed through the budgeting and reporting process. Western Power clearly document its processes and applies them with rigor.

Western Power, as is typical of network companies, is focused on identifying and managing high value capital investments to ensure the safe and reliable operation of its network. Many of these capital programs are quite operational in nature and encompass a substantial amount of the activity performed by the organisation.

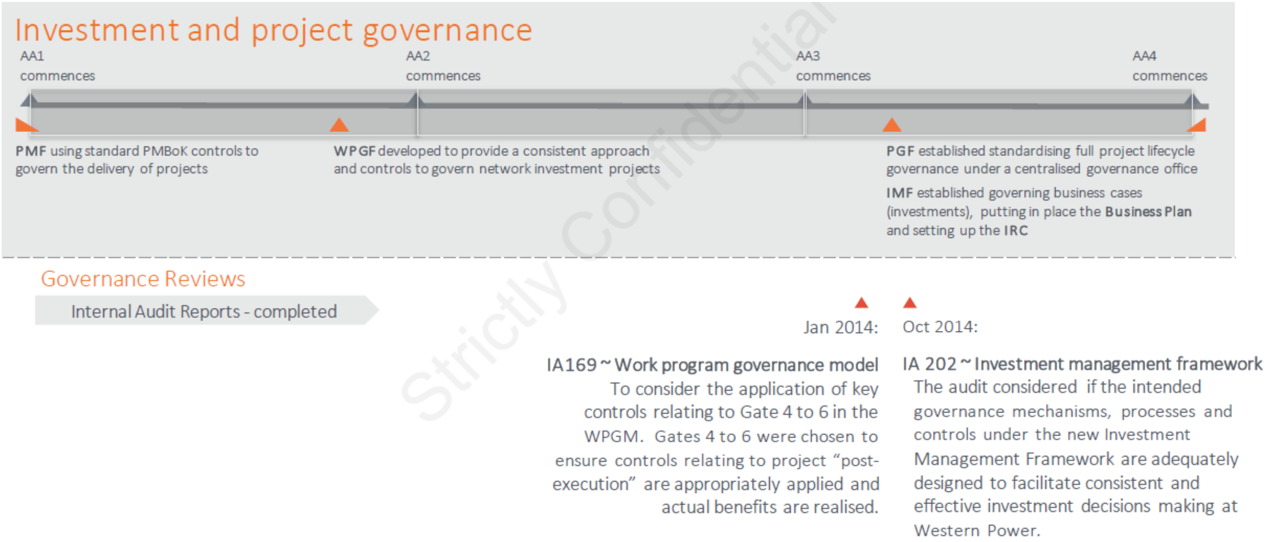
However, there are large programs of work which fall outside of capital programs, particularly maintenance and inspection. These areas of operation are discussed explicitly in the asset strategy documents. From our review of this documentation, we consider that they are being addresses in a coordinated fashion with capital investment programs. However, in an unusual omission, Western Power does not to have an explicit OPEX governance document, or section of the Investment Governance Framework that outlines how these large operational programs are created, approved and managed.

Based on answers to questions at the presentation and subsequent information requests it is clear that Western Power has detailed processes for budgeting and measurement of operational expenses. We did examine two monthly business performance reports, along with one set of board meeting minutes. In addition we note how maintenance and inspection programs were covered in detail in Asset Class Strategies. Our review confirms the responses at the presentation and our comfort that OPEX is being managed closely. However, as stated, there is a lack of documented process for governing operating expenditure.

4.6 Governance journey and progress since AA3 submission

Western Power has made a considerable investment in its governance processes during the AA3 period. Noted below is a timeline of the changes in governance frameworks. In the process of redesigning their governance framework they have made considerable progress in addressing the governance issues raised in the AA3 technical review.

Figure 11 Investment and project governance timeline[14]



The key issues raised on governance in the last review included:

1. Little evidence that defined governance processes were actually embedded in the governance of individual projects
2. In the design phase there was limited creation of alternative options to identified issues
3. Western Power lacked an effective quantitative risk assessment tool
4. Management of asset condition data was not strong

From our review of governance policies, processes and procedures incorporated into Western Powers AA4 submission, we consider that the organisation has addressed each of these issues in the changes they have instituted.

In our review of business cases, it is clear that the business case preparation team has actively researched real alternatives in the preparation of the business case. Only in one business case was only one other viable alternative considered. In this case the preferred option was supported by a detailed risk assessment using Western Power's NRMT tool.

During the AA3 period Western Power has invested heavily in creating a viable quantitative risk tool the NRMT. While the tool does not cover all asset classes it does address the most important ones. By using this tool Western Power is able, at a strategic level, to create risk based asset strategies and at an individual asset level examine different alternatives from a risk perspective. As the data used within the model gets more comprehensive the quality and reliability of the tool should improve. However, as stated above, given how important the tool has become in the investment process, it should be subject to rigorous review to test its validity during the AA4 period.

The NRMT and other changes to the asset strategy and project identification procedures are very dependent on the quality of asset data. Western Power has made significant investments in mobile technology to help improve the timeliness and accuracy of inspection data in the asset management systems. By leveraging this technology the organisation can now make far more informed and accurate decisions which should improve both capital investment and operational efficiency.

[14] Governance journey presentation, p. 2

4.7 Conclusions and Recommendations

Conclusions

- The Investment Governance Framework and associated Portfolio Management Standard, Investment Management Standard and other supporting documents provide a good basis for governance of investment decisions and project delivery. They address the four core principles of good governance; specific goals, clear accountability, documented processes and measurement of performance well, with few areas of ambiguity or lack of clarity.
- The Investment Governance Framework is supported by the AMF which through its execution provides core information for network planning and asset strategies which leads to the individual projects that make up the corporate project portfolio. Western Power has made substantial investments in key parts its AMF. This has enabled the organisation to understand its asset base better which should lead to more efficient management of the network. Of particular interest has been the improvement of asset performance data collection, providing a more timely and accurate picture of asset condition. This goes some way to rectifying a previous weakness. The other area of investment is the creation and development of the NRMT. While it is still being fully developed it is being used to drive investment decision by allowing for a quantitative risk assessment of different options. This tool has the capability to substantially change how Western Power assesses its asset base and how it makes investments to build it into the future.
- Good governance processes are only as good as their application. In the documents that we have reviewed to date we note that Western Power has generally been applying its governance policies, processes and procedures in accordance with what is required by the relevant standards or guidelines. However, there should be additional focus on progress reporting to ensure that project operational and financial risks are managed effectively. Enhanced progress reporting will also assist Western Power to improve its contract management engagement.

Recommendations and observations

- The effective matching of top down strategy and bottom up driven investment requirements. There needs to be a genuine two way conversation between those that allocate capital and the sponsors of individual asset classes in the creation of investment plans. If top down capital allocation becomes overly dominant in the creation of investment plans the capital required to maintain asset reliability and operational performance may not be made available. This could lead to higher operational risks and poorer service outcomes. We do not have evidence that this imbalance has occurred. However, it is an inherent risk with top-down driven capital allocation approaches.
- The governance process is complex, particularly with the proliferation of standards and guidelines. While we are in favour of providing process clarity, we would suggest that there needs to be balance between executing the right governance processes correctly with the actual benefit derived from the application of the process. We would recommend that Western Power looks to simplifying its processes where possible and reducing the administrative burden, particularly for smaller capital project sizes.
- Operational expenditure governance has not received the same level of attention as capital investment. From the evidence we have reviewed it would appear that operational expenses are being closely monitored. However, despite this evidence we consider it to be an oversight not to have created OPEX governance documents. It is therefore our recommendation that OPEX governance documents are prepared and utilised. They should be closely aligned with the Investment Governance Framework and

should not duplicate activity, however they should clearly outline the process from strategy to planning and budgeting, through to execution and measurement of performance.

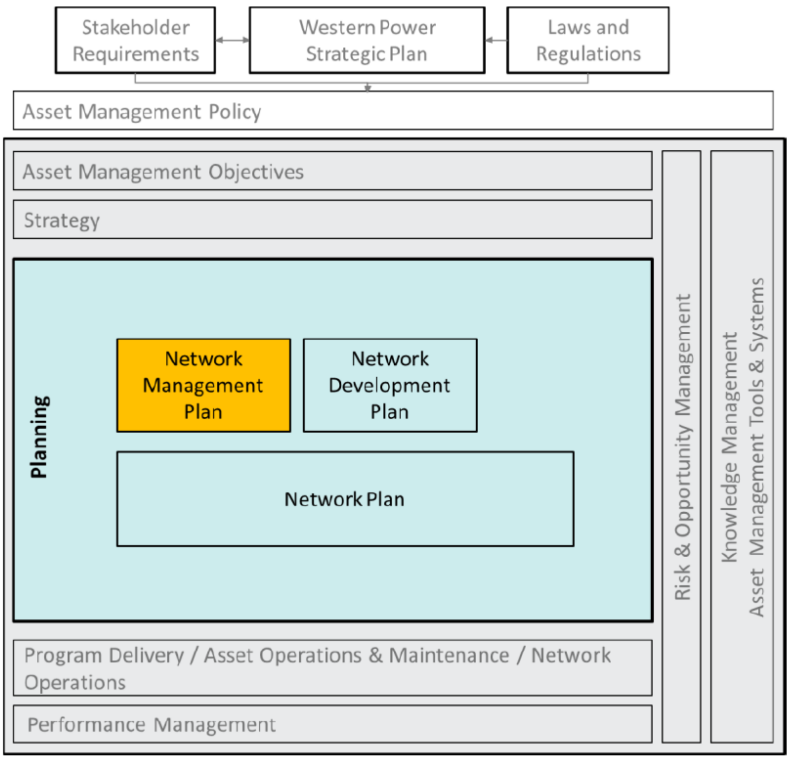
5. Asset management

We have reviewed the asset management practices across various relevant documents for the purposes of assessing the efficiency and prudency of:

- The level of maturity and effective integration of asset management practices within the business
- The effectiveness of how data, information and business processes lead to sound decision making to balance, risk, service levels and costs and how well these decisions align with the business objectives and customer needs
- The Asset Strategies for capital renewal and compliance projects and maintenance expenditure requirements which underpin the 10 Year forecast capital and operating budgets and the revenue requirements for the AA4 period.

The principle documents reviewed were the AAI AA4, the NMP and the NDP. These documents form the core of Western Power's AMF as shown in the following diagram.

Figure 12 Western Power Asset Management Framework



"The NMP is the first point of reference for any queries in relation to Western Power's consolidated view of strategies and plans for renewal and maintenance of its current network asset portfolio."

5.1 Maturity and effective integration of asset management practices

Each component of the AMF is made up of a suite of documents, tools and systems that form Western Power's asset management system (AMS). The structured approach fulfils key asset management process requirements with continuous improvement objectives in line with the requirements of ISO55001. Collectively these documents, tools and systems are referred to as the AMS.

The NMP provides the technical overview and strategic plan required to optimise the lifecycle management of the network assets. It also includes the ten-year capital and operational expenditure volumes for maintenance and renewal. The NDP capital requirements are predominately driven by proposed augmentation works. However, some overlap exists with like for like replacement expenditure. Overlaps typically exist for transmission assets that are characterised as being large, bulky with high replacement costs and long lead times. Together the NMP and NDP form the critical inputs into Western Power's business plan.

It is evident that significant improvements have been made to Western Power's AMS, both in the definition and documentation of the underlying Asset Management standards, processes, methodologies and tools, and, their application. These improvements have assisted Western Power in developing a mature understanding of its assets that positions the organisation to implement advanced practices in the areas of network risk and performance management.

The AMS has undergone an independent assessments for maturity, adequacy and application in August 2017 by Cutler Merz[15]. Cutler Merz found "*the maturity of Western Power's Asset Management has significantly strengthened over time, particularly in relation to strategy, objectives, sophistication of approaches and supporting tools*". The report recognised that "*Western Power's approach to risk based Asset Management can be considered as amongst the industry leaders, particularly when applied to asset maintenance and renewal.*" It acknowledged the existence of *"comprehensive and rigorous processes resulting in effective Asset Management plans, underpinned by systematic management and monitoring of operational activities and program delivery, enabling the desired outcomes to be achieved."*

The NMP consistently links to the asset objectives and feedback provided by customers, and increasingly the asset strategies are being based on sound information and data. Western Power recognises that further improvement can be made with respect to asset data and the condition and relevant failure characteristics and furthermore the environmental factors which can enable asset strategies to be segmented and targeted. A review of a select sample of asset strategies has identified some issues in the use and interpretation of data which is symptomatic of the development of the processes. Most of these issues are not significant in that they do not materially impact on the appropriate asset strategy being chosen.

The NMP has been improved in both breadth and depth with the intent to provide internal and external stakeholders with greater transparency and increased granularity of the Asset Management approach, underlying processes, strategies, plans and expected outcomes. We consider that the documents have succeeded with this objective and that the approach and processes are set up to achieve efficiency and prudency of strategies and expenditures to achieve customer needs, provide safe operation and at the lowest cost.

The development of asset strategies considers the type of asset, associated risks and consequences of failure. The risk management and options analysis tools are designed to assess the criticality of the network assets, and the potential consequence of failure in conjunction with the condition assessment of relevant failure modes. This analysis is used in forecasting future asset replacement investments and then considered together with growth, compliance and reliability project proposals as part of Western Power's overall business planning process and the Investment Governance Framework.

The NMP provides an overview of key asset management challenges and strategies associated with asset groups in the form of an asset state (risk, failures and percentage of assets exceeding their MRL. MRL is becoming a common method in the industry to indicate potential risks if a growing percentage of assets

[15] Cutler Merz, *2017 Asset Management System Review - Final Report*

exceed the expected mean life of the assets. However, for assets with a wide distribution of potential life, there statistically should be an expected percentage above the MRL which remain in a serviceable condition is outlined in Appendix B of the NMP.

Western Power does state in the NMP that exceeding MRL does not mean an asset is likely to fail immediately, however the frequency and severity of defects and the likelihood of in-service failure are expected to increase. Using the MRL value alone and the percentage of assets that exceed this value tends to imply that unacceptable risk exists which may not be the case.

For example, Table 271 in Appendix B of Western Power's NMP 2017/18-2027/28 shows that standard deviations can range from around 5 years to the highest at 21.69 (wood poles).

A better value for indicating risk exposure could be the percentage of assets above one standard deviation above the MRL for a given asset class. However, we recognise that MRL is an indicator only of a heightened risk and that asset strategies are still developed by Western Power based on detailed risk assessments. Another measure that is often used is the actual mean life versus the MRL. This measure indicates the relative position of the actual population of assets compared with the expected life of the population. Regardless of which measure is used the purpose should be to flag a current or near future heightened risk and to flag a potential wave of heightened risk with an asset class.

The following examples[16] are noted (in the context that the percentage of assets within one standard deviation above an asset class's MRL is 18.27% for a normal distribution):

- For transmission power transformers, replacing only on failure will result in the current 6% beyond MRL increasing to 19% by 30 June 2022 and 29% by 30 June 2027. Implementing the current asset strategy is projected to have 17% beyond MRL by 30 June 2022 and 26% by 30 June 2027. This implies a potential unacceptable increase in risks associated with over-age assets. The MRL has been determined to be 54.98 years with a standard deviation of 14.05 years. However, transformers with an age up to 69 years should be expected. Once the number above the MRL exceeds 18.27% then this situation is of concern as it will lead to an increase in unacceptable network performance.
- For distribution hard wood poles, the assessed MRL is 69.22 years with a standard deviation of 14.74 years. Replacing only on failure will result in current 7% beyond MRL reaching 20% in 5 years and 34% in 10 years. Implementing the current asset strategy is forecast to have 15% beyond MRL in 5 years (30 June 2022) and 20% in 10 years (30 June 2027). This could imply an unacceptable increasing risk whereas the assets are being appropriately managed if the number above MRL does not significantly exceed 18.27%.
- Distribution overhead high voltage (OH HV) switchgear has an assessed MRL of 23 to 26 years and a standard deviation 12 to 21 years depending on the type. Without replacements, the current 17% beyond MRL is expected to increase to 22% by 30 June 2022 and 27% by 30 June 2027. Implementing the current asset strategy is projected to have 18% beyond MRL by 30 June 2022 and 18% by 30 June 2027. The relatively large standard deviation does indicate that the distribution is not a normal distribution. The % > MRL of 18% should indicate the replacement strategy is appropriate for this asset class but could imply a high risk situation to some readers of the NMP. The replacement strategy in this case is being driven by the need to mitigate bush fire risk.
- Transmission underground cables has a MRL of 40 years with a standard deviation of 6.32 years. Replacing only on failure is expected to result in existing 33% beyond MRL increasing to 39% by 30

[16] Western Power, *Network Management Plan: Transmission and Distribution 2017/18 - 2027/28*, EDM #34159326, August 2017. Discussion about existing transmission asset populations in sections 5.3 and 5.4, pp. 77-134, distribution assets in sections 5.5 and 5.6, pp. 135-184 and the projected impact of asset strategies in table 269, pp. 244-5

June 2022 and 40% by 30 June 2027. Implementing the current asset strategy is forecast to maintain 33% beyond MRL by 30 June 2022 and 34% by 30 June 2027. This situation should be concerning but what seems to be questionable in this case is the calculation of the MRL and/or the standard deviation is too low.

The point of this critique is that Western Power should reconsider defining the percentage of assets above one standard deviation above the MRL for the benchmark to indicate heightened risk associated with the population of each asset class.

The percentage of assets above MRL is also a good indicator of required future investment for sustaining capital or alternatively past underinvestment in sustaining capital. However, Western Power does not show measures of asset utilisation. These measure for substation and feeder capacity can provide an indication of capital investment efficiency.

NSPs often measure asset utilisation, principally zone substation transformer utilisation. It is a lagging indicator of past investment efficiency in capacity. Alternatively it indicates spare capacity invested to provide for growth. In times of low growth it will become more important to be capital efficient with respect to sustaining capital expenditure.

The AER publishes an Annual Benchmarking Report which uses a multilateral total factor productivity (MTFP) approach to compare efficiency between electricity NSPs. The capital partial productivity factor measures the annual cost of capital invested in the network to supply the services. For DNSPs the benchmarking uses five inputs; overhead sub-transmission lines, overhead distribution lines, underground sub-transmission cables, underground distribution cables and transformers.

Asset utilisation measured for these five categories would provide approximate indicators of capital productivity and by excluding the km length of lines and cables from the indicators, it can serve Western Power to demonstrate efficient use of capital compared with other NSPs with different load density and geographic coverage.

5.2 Effectiveness of data, information and business processes

Western Power's Asset Management System is underpinned by the Ellipse enterprise management system which contains data on the assets, the condition, maintenance history and costs. Western Power has implemented a suite of IT solutions with three core tools used to analyse, plan and to establish asset replacement and maintenance strategies (AAI clause 588). The three tools are:

- NRMT - a statistical modelling software used to calculate a risk score for each individual asset within each particular asset class.
- 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.
- 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.

The benefit of these developed IT solutions is that it allows Western Power to more accurately and consistently quantify risk and maintain oversight of the condition of our assets and associated investment activities.

The Asset Management System is supported by a documented framework and library of policies, standards strategies and plans. Cutler Merz acknowledged the existence of *"comprehensive and rigorous processes* *resulting in effective Asset Management plans, underpinned by systematic management and monitoring of operational activities and program delivery, enabling the desired outcomes to be achieved."* We concur with this view based on the documents and systems reviewed.

These IT tools and systems depend on accurate, reliable and informative data, and Western Power acknowledges that incomplete data, accuracy and consistency of data is a problem which is being addressed through refinement of data collection requirements and processes designed to collect and validate information on its assets. We expect that as data accuracy improves along with the implementation of advanced ICT systems that further refinement of asset strategies and delivery processes will have the potential to improve efficiencies during AA4 and into the next fifth access arrangement (AA5) period.

Work planning, scheduling and field mobility tools and practices have been implemented which are also delivering efficiencies. 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 time updates to enterprise systems

A key attention area for Western Power over the course of the AA4 period will be in preparing for how new technology is likely to play a significant role in the future of Western Australia's electricity systems over the coming years, and how Western Power has to adapt to these changes for the benefit of its customers. Breakthroughs in new technology, distributed storage, and standalone power systems over the AA3 period indicate that the role and nature of the electricity network may look very different in the future.

At the moment the majority of our expenditure forecast relates to traditional poles and wires solutions but the emergence of battery storage systems, microgrids and more advanced distributed generation systems will mean the network will need to be operated and developed differently to today. We consider that Western Power is preparing for this change as evidenced by proposed investments in ICT, SCADA and communication systems and which aligns with customer feedback.

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. The use of advanced meters will be a significant enabling technology for a range of Demand Management /Non-network initiatives in the future.

However our review of Western Power's Advanced Metering Business Case highlights an issue associated with investments which provide sufficient benefits for Western Power alone with respect to its covered services, yet the benefits across the whole electricity market value chain would demonstrate a positive net present value (NPV). We consider it prudent that investments are considered that will enable new emerging technologies however the regulatory and market approach mechanisms to capture and deliver those benefits to consumers needs to be determined. This is discussed further in the review of the Advanced Metering Business Case in section 10.2.3.

5.3 Asset strategies underpinning CAPEX and OPEX 10-year forecasts

The planned CAPEX and OPEX volumes in the NMP have been prepared based on asset class strategies and reflect the investment required to implement the strategies outlined in the NMP. The expenditure requirements for the AA4 period are summarised in the business plan and reflect a significant reduction in asset renewal CAPEX and OPEX expenditure compared to the actual expenditure in the preceding AA3 period.

Western Power's proposed efficient base year operating expenditure is 28 per cent lower than the 2016/17 recurrent OPEX forecast approved by the ERA in its AA3 further final decision. The recurrent OPEX approved by the ERA for the AA3 period was $444 million ($2016/17) compared with the proposed $318 million 2016/17 efficient base year (AAI clause 470).

The 2016/17 efficient base year amount incorporates efficiencies 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 (AAI clause 477). This total equates to 32.2% of the AA3 period annual OPEX expenditure allowance and the indirect savings related to strategy and process improvements equates to 9.8%.

Western Power's believes that the improvements to asset strategies, procurement processes, and work practices mean that operating costs have been [redacted] to a point where they expect to be able to maintain current service levels at the expenditure levels proposed for the AA4 period (AAI clause 478).

Western Power has also forecasted efficiency adjustments during the AA4 period:

- A $5 million per annum step change in recurrent OPEX from 2017/18 associated with BTP initiatives that were not completed prior to the start AA4 period (1 July 2017) (AAI clause 481).
- Further reductions of 1% per annum in productivity improvements over the AA4 period. This represents a cumulative reduction of around 5% by the end the period. (AAI clause 492).

The benchmarking study commissioned by Western Power[17] indicates that the efficiency gains would move Western Power from 10th position amongst Australian distributors to 4th position. However, all Australian entities, particular the now privatised New South Wales entities will be pressing for efficiency gains equal to Australian frontier operating companies and looking at benchmarks with international frontier companies.

We have benchmarked Western Power against other distributers in Australia (refer section 7). Our predicted efficient OPEX for the Western Power combined network in 2016/17 is in the range $368 million to $379 million which includes indirect costs and escalations. From Table 92 in section 7, the first year of AA4 is forecast to be $375 million, which is at the top end of the efficient range and includes allowances for the final year of the current BTP. For subsequent years in AA4, our alternate annual forecast expenditure is approximately $342 million which is below the lower end of the benchmarked efficient OPEX range.

We are of the opinion that greater efficiencies than 5% should be achievable in total by the end of the AA4 period with the proposed corporate capital expenditure which Western Power has proposed. This level of savings in operating expenditure should be able to be achieved through further improvements to asset strategy refinements alone, and through specific targeting of the poorer performing assets in the network to reduce corrective maintenance spend.

The forecast corporate CAPEX includes investment in property, plant and equipment as well as upgrades and replacement of existing ICT systems (AAI clause 683). The majority of this expenditure is considered sustaining capital although a large position is targeted investment for future efficiency returns. Forecast corporate CAPEX for the AA4 period is $230 million (68 per cent) higher than that incurred during the AA3 period (AAI clause 684).

[17] Synergies - Benchmarking Productivity Performance Report (YE16) - 10 Oct 2017

During the AA4 period, Western Power will invest $569 million of capital in corporate support. The primary driver for this CAPEX increase is the need to modernise Western Power's portfolio of metropolitan and regional operational depots, many of which are in poor condition (AAI clause 685). Other corporate real estate projects proposed for the AA4 period include relocation of Western Power's Network Operations Control Centre (AAI clause 686). Our review of this expenditure in Section 11.2 concludes this expenditure to be reasonable.

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 the recent BTP (AAI clause 687). A key outcome of the BTP 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 (AAI clause 688).

We consider that the investment in ICT is necessary and prudent with respect to the replacement of the existing transmission and distribution SCADA and IT systems. This investment though should be contributing to lowering operating costs by the end of the AA4 period. The ICT associated with the Advanced Metering Business Case as detailed in section 10.2.3 does not meet the requirements of NFIT requirements and has been removed.

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 (AAI clause 677). The decrease in distribution CAPEX is offset to some extent by an increase in transmission network asset replacement and renewal (AAI clause 678). The increases in asset replacement compared to the AA3 period is partly 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 following is a summary view of the significant asset replacement programs:

- Pole management (AAI clauses 591 to 598).
  - 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 EnergySafety Order 2009-01, which required Western Power to address the safety risk associated with its rural wood pole population.
  - Based on improved asset knowledge and application of enhanced risk assessment methods, many asset strategy rules for asset selection for treatment have been revised. This has resulted in a reduction in volume of assets that require treatment. The majority of poles with the greatest identified risk were treated during the AA3 period.
  - Overall expenditure on pole management during the AA3 period was $1,158 million.
  - Forecast expenditure on distribution wood pole replacement / reinforcement in AA4 is $634 million.
  - We note that the risk profile associated with transmission support structures (no High rankings, 3 Medium rankings) is relatively lower than that for distribution support structures (3 High rankings, 2 Medium rankings). The proposed replacement CAPEX for transmission structures is sufficient to reduce the percentage of assets in-service beyond the MRL to 0%, whilst the percentage of distribution wood poles in-service beyond the MRL grows from 7% to 20% by the

end of AA4, and projected to increase further to 34% by the end of AA5 with projected pole replacements and reinstatement programs.

  - Transmission wood poles have been assigned a MRL of 62.39 years and a standard deviation of 21.69 years which differs from distribution wood poles with an MRL of 69.22 and a standard deviation of 14.74 years (Pre-1960). The replacement volumes for transmission poles appear to be too high which is balanced by the replacement volumes for distribution poles being too low. This is further addressed in section 11.3.2.
  - Western Power indicates that the investment is linked to the quality of condition data, and targets assets with historically high likelihood of failure, so we would expect that Western Power will not allow the risk profile of the current wood pole population to be compromised should condition assessment recommend replacement or reinforcement in volumes beyond those forecast, particularly given that the current replacement/reinforcement volumes project a potentially higher risk profile by the end of AA5.
  - We consider the combined volumes for both transmission and distribution poles specified for the AA4 period to be appropriate to maintain the population of assets at a reasonable risk profile by the end of the AA4 period.

- Conductor management (clauses AAI 602 to 605)
  - Conductor asset management practices improved during the AA3 period, resulting from conductor testing and sampling which has given Western Power a better understanding of asset condition and the likelihood of asset failure.
  - Western Power has been able to adopt a more mature risk based renewal approach to managing conductors during the AA4 period.
  - Forecast expenditure on conductor management during the AA4 period is $282 million. This is 42 per cent less than incurred during the AA3 period and we from our analysis of the data, we consider the volumes specified for the AA4 period to be appropriate to maintain the population of assets at a reasonable age profile by the end of the AA4 period.

- Connection management (clauses AAI 608 to 610)
  - During the AA3 period, Western Power removed the known highest risk service connections (referred to as ‘twisties’) from the network.
  - Western Power has proposed to move to a program of condition-based asset renewal, using data extracted from AMI (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.
  - The condition-based renewal forecast is noted to be dependent on the installation of the AMI to detect neutral integrity and avoid reported electric shock. This methodology though is based on a volume of advanced meters being installed at each premises in order to monitor customer connections or types of installed connections and we expect this to take 7-8 years to reach a 50% population under the proposed Western Power program.

- o Through our analysis, we have found the Advance Metering Business Case will not provide a positive net benefit as presented. The removal of the AMI will have implication to the asset strategy adopted for conductor connections, and as a result, Western Power will need to review their proposed asset strategy for conductor connections.
  - o We are of the opinion that a small increase in risk can be managed through the AA4 period with the current proposed replacement volume for connections.
- Bushfire management (clauses AAI 611 to 613)
  - o Activities such as replacement of poles, reinforcement of poles and conductor replacement are significant contributors to bushfire management.
  - o The primary bushfire management activity for the AA4 period is the 'high voltage conductor clashing program'.
  - o Bushfire management expenditure during the AA4 period is $31 million, which is 21 per cent less than incurred during the AA3 period.
  - o Western Power states that the lower expenditure level is due to a change in asset treatment compared to the AA3 period, which will see a higher number of automated reclosers installed on the network.
  - o During the AA3 period Western Power found that installing reclosers is more effective and efficient method of mitigating bushfire risk compared with re-designing long bays. In high and extreme bush fire risk zones (FRZs) and conditions, fast protection settings are activated on automated reclosers and auto reclose is disabled.
  - o We are satisfied that Western Power has improved bushfire management during AA3, and consider the proposed replacement volumes and risk mitigation strategies reasonable for the AA4 period
- Power transformers (clauses AAI 621)
  - o From the NMP, the percentage of power transformers beyond MRL is expected to increase from a current 6% to 29% by 2027 if replaced only on failure, which indicates an increasing risk. The MRL has been determined to be 54.98 years with a standard deviation of 14.05 years. As a result, transformers with an age up to 69 years should be expected. We consider transformers exceeding 70 years of age or the percentage between 55 and 70 years being over 18% of the total population a concern; hence the expenditure could be expected to increase during AA5.
  - o However while Western Power reports many transformers as being in a poor or bad condition, the reported failure rate is lower than the average in Australia. When we calculate the failure rate determined based on condition use in the asset strategy[18] the risk is 0.52% failures per annum whereas Western Power's actual reported failure rate is 0.29%. This suggests that their assessment of power transformer condition, on average, is likely more conservative compared with standard industry practice.
  - o We have reviewed the power transformer asset management strategy in further detail in section 11.2.1. Western Power plans to mitigate the risks associated with remaining poor/ bad condition transformers using rapid response transformers and spare transformers being deployed as required. In addition, 1 reactive replacements, 2 strategic spares and 1 mobile transformers are

[18] Asset Class Strategies-Power Transformer Asset Management Strategy_(33141537)

included in the plan. The overall approach appears reasonable with refurbishment being able to resolve some of the issues and deferring full replacement cost which is both an economic solution, allows more timely action to improve the asset and avoids long duration security risks with outages.

  - Age of power transformers, other primary plant, secondary systems and underground cables are well above their MRL. We consider an increase in expenditure to address this is likely to be required to reduce the risk of reducing reliability of the transmission network and to avoid larger expenditures required in future periods.

- Maintaining service levels (clauses AAI 615 to 622)
  - Western Power will invest $296 million to replace transmission assets such as power transformers, circuit breakers, switchboards, static VAr compensators (SVCs), protection systems, and primary plant.
  - Investment in replacement of two key SVCs have been deferred over the last two regulatory periods and the condition of these SVCs is considered to be poor leading to reliability issues.
  - 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 Terminal Station.
  - This increases proposed expenditure on transmission and distribution asset replacements from $60 million to $89 million per annum is a significant increase. The increase for transmission only component of asset replacement and renewal is from $37 million to $59 million.
  - Western Power has stated that their investment is designed to address existing network security and power quality issues, which we consider necessary if current reliability levels are to be maintained. We note that the age of these assets are well above their MRL and deferring expenditure in replacements in the AA4 period will result in larger expenditures required in future periods and unacceptable risks to service levels.

- Improving efficiency of Western Power operations (clauses AAI 644 to 668)
  - During the AA4 period, Western Power will invest around $933 million on projects designed to enable the business to operate more efficiently.
  - Expenditure includes ICT investment, modernisation of existing depots and development of new site, an upgrade of SCADA and communications systems, and investment in advanced metering
  - Western Power proposes to invest $209 million in advanced metering communications and associated ICT Infrastructure and meters. Assessment of this program is provided in section 10.2.3 which indicates to us that there is not a positive net benefit to Western Power for its covered services.
  - Western Power proposes to 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. Western Power considers that the increase in investment is required to replace obsolete SCADA and Communications equipment and maintain the performance of system monitoring and control and we support this view.

- 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. We are of the opinion that greater efficiencies than 5% should be achievable in total by the end of the AA4 period with the proposed corporate capital expenditure which Western Power has proposed. This should reflect in either lower OPEX or in efficiencies in the delivery of its services.
- Most of the relative increase in ICT CAPEX relates to upgrades and replacements of existing ICT systems that Western Power advises are out of date or nearing end of life. As stated by Western Power, these changes are designed to improve business processes and help to realise the efficiencies that were identified in the BTP. We consider this CAPEX requirement is necessary however we also expect lower OPEX as a result, towards the end of the AA4 period.
- A significant operational efficiency project is proposed for modernisation of Western Power's metropolitan and regional operational depots. Western Power has advised that most of these depots are dilapidated and require substantial upgrade and repair works. Forecast CAPEX on depots during the AA4 period is $220 million. Phase one of the program is aimed at delivering recurring expenditure savings of $10 million per annum, and one-off benefits of $60 million.
- 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.
- Our review of the required expenditure for modernising depots and relocating the network control centre in section 12.2.1 concludes this expenditure to be reasonable.

A majority of this expenditure is sustaining capital although a large position is targeted investment for future efficiency returns. We consider that the investment in efficiency of Western Power operations is prudent. However, it should contribute to greater savings in operating costs by the end of the AA4 period than is currently offered by Western Power.

- Satisfying compliance requirements (AAI clauses 669 to 673)
  - During the AA4 period, Western Power has proposed to invest $161 million on satisfying compliance requirements. There is an increase from less than $15 million over each of the previous three years in AA3 to around $30 million for each of the five years during the AA4 periods
  - The largest program relates to transmission substation security ($87 million) to comply with National guidelines introduced in 2015 relating to protection of critical infrastructure. The overall expenditure on security dominates the compliance expenditure forecast for AA4.
  - We have reviewed further the proposed expenditure for substation security in section 11.3.1. We disagree with the broad conclusion of the Western Power substation security review report regarding the prudency of classifying the entire SWIN as critical infrastructure, as we consider this was not the intent of the National Guidelines or the WA Office of the Auditor General, nor do we consider a blanket assessment of criticality is sufficient.
  - To satisfy the definition for critical infrastructure, we would expect to see specific risk assessments under the NRMT for each substation, and for these to be prioritised in accordance with the WA Office of the Auditor General definition for services that are essential to the State's social and economic well-being.

- Another major transmission compliance program is transformer compliance related to oil containment and noise emission control and firewalls to comply with current standards ($15 million).
- In the distribution network, the largest non-safety driven compliance program is addressing customers' power quality complaints ($25 million).
- We are of the opinion that business risks on the other compliance requirements justifies the expenditure.

We were not able to comment directly on changes of volumes for transmission and distribution maintenance activities as no information was provided by Western Power to evaluate unit volumes for maintenance. The reduction in volumes through developed asset strategies during the AA3 period has resulted in savings in maintenance costs which we believe are valid and the reliability and risks of operating the network will not be compromised through those changed strategies. The following is a summary view of maintenance strategies and expenditure forecasts for AA4 (AAI clauses 469 to 470):

- Distribution maintenance OPEX
  - The AA4 proposed expenditure by Western Power is around $150 million for distribution maintenance via significantly reduced routine maintenance activities achieved during the AA3 period as the following examples demonstrate.
  - Conductor sampling and management has improved knowledge of the current condition, aging characteristics and remaining life of conductor assets to deliver a targeted strategy which is anticipated to deliver $15 million recurring savings per year from 2016/17 financial year.
  - Standardising depot tasks by changing the scheduling approach, has reduced the size of work crews which has reduced operating costs per job. 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
  - Adopting 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
  - Deployment of enhanced technology (LiDAR) to get more accurate and holistic information on geometric configuration of the network their condition and condition of surrounding environment (for e.g. vegetation).
  - Revision of treatment rules of defects to remove the need for treatment of low risk defects that exhibit lower probability of failure/ likelihood of consequences.
  - Bundling the condition assessment requirements of different asset classes (including vegetation inspection needs) into common inspections to create more efficient use of resources over a wide geographic area
  - Optimising the scope and frequency of inspections, taking into consideration condition and location of the asset

- Transmission maintenance OPEX
  - The AA4 proposed expenditure by Western Power is around $42 million for transmission maintenance.
  - The expenditure in non-recurring operational expenditure is significantly reduced, owing to greater removal of redundant assets and higher strategic planning costs in the AA3 period.
  - Generally investment across other categories is reduced due to enhancement of asset strategies and more efficient methods of program planning and delivery.

6. Forecast method

6.1 Demand forecast

Western Power's AA4 period capital expenditure forecasts were underpinned by detailed network planning using its 2016 demand forecasts, and later reviewed after taking into account the updated 2017 demand forecasts. We have reviewed the basis of the 2017 demand forecast after reviewing written documentation of:

- forecast preparation methods, processes and quality reviews
- overall network energy, customer numbers and peak demand forecasts
- maximum demand forecast by zone substation

A third party review of the 2016 demand forecasts was undertaken by NIEIR (August 2016), which found that Western Power's method, processes and assumptions underlying the energy, customer number and peak demand forecasts were "reasonable, robust and fit for purpose". The review made some suggestions for improvement, most of which were incorporated into the 2017 forecast preparation process.

6.1.1 Energy and customer numbers

Energy and customer number forecasts are developed on the basis of 17 customer categories connected across the entire Western Power network, distinguished by their type of network tariff. For each category, three underlying trends are identified and projected into the future:

- the number of connections
- the average energy consumption per connection
- the adoption of photovoltaic solar (solar PV) systems

The estimation and diagnostic testing of statistical models, including the choice of models including autoregressive integrated moving average (ARIMA), unobserved components and multivariate regression, and development of the forecasts, is in large part automated within the SAS Forecast Studio software. Independent variables in the energy consumption models include measures of economic activity, population growth, electricity price, weather and solar PV capacity, all of which may drive electricity consumption. The process and the model drivers used as inputs are reasonable, but we have not seen any examples of specific output on which to make further comment on the efficacy of any specific estimated model.

In contrast to other utilities which attempt to account for energy supplied by customers' own rooftop solar generation behind the meter as a separate adjustment, the approach taken by Western Power seeks to incorporate the capacity of solar inverters directly into the econometric models. While this is a sound approach, the resulting energy forecast nonetheless still depends in part on an independent forecast of inverter capacity (as it does with other utilities' forecasts).

Table 9 summarises recent and forecast energy and customer numbers. The average number of customer connections across all tariff types was 1,097,045 in 2016/17, excluding street lighting and unmetered connections. This is forecast to increase steadily by 1.6 per cent a year to 1,191,890 by 2021/22. Tariffs types are differentiated by residential and business, by high and low voltage including a demand component, between 'anytime' use and times of use and between net tariffs and newer bidirectional tariffs. The greatest increases in connections are forecast in the time of use business bidirectional, anytime bidirectional residential, and time of use residential tariffs, while the greatest decreases are forecast in the number on residential unidirectional time of use tariffs. Street lighting connections, which make up an additional 21 per cent of total connection numbers, is also forecast to increase strongly.

Energy consumption grew by an average 1.2 per cent a year in the last five years, reaching 17,765 GWh in 2016/17, but is forecast to fall by around 0.6 per cent a year during the AA4 period.

Table 9 Energy and customer numbers

Actuals	2012/13	2013/14	2014/15	2015/16	2016/17	Average annual growth
Average customer numbers	1,008,664	1,028,397	1,052,994	1,076,765	1,097,045	2.0%
Grid supplied energy consumption (GWh)	17,043	17,509	17,587	17,874	17,765	1.2%

Western Power 2017 forecasts	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 average annual growth
Average customer numbers	1,115,509	1,134,897	1,154,255	1,173,585	1,191,890	1.6%
Grid supplied energy consumption (GWh)	17,698	17,663	17,628	17,502	17,309	-0.6%

Source: Western Power

The forecast decline in energy stands in contrast to the recent history of grid energy consumption and the forecast continued increase in customer connections, but may be explained by increasing take-up of rooftop solar PV systems, used by customers increasingly to generate their own energy.

6.1.2 Maximum demand

Western Power's peak demand forecasting is focussed, for network planning purposes, on the preparation of zone substation coincident and non-coincident demands at both the 10% probability of exceedance (POE 10) and 50% probability of exceedance (POE 50) level. This process begins with the use of econometric methods to develop models of average demand (energy) at each location, which are then used to prepare forecasts of average demand. This process is similar to the preparation of network energy forecasts described above.

Maximum demands forecasts are derived from projected load factors and average demand using the following relationship:

$$Maximum\ Demand\ (MW) = \frac{Average\ Demand\ (MW)}{Load\ Factor}$$

To correctly ascribe the POE 10 and POE 50 levels of maximum demand when forecasting using this method, the load factors must be calculated using maximum demands that are corrected to accurate POE 10 and POE 50 levels, based on the analysis of historical data. A reasonable number of years' history of such data is also required to accurately identify and extrapolate any observed trend in the load factors over time. Western Power undertakes weather correction using estimated relationships between demand at each location and a measure of maximum daily temperature. Multiple predictions from each relationship are then used to determine the 50th and 90th percentiles of demand which are then used as the POE 50 and POE 10 maximum demands at the particular location, respectively. This approach is typical of the practice of other utilities. The load factor forecasts implicitly include future trends in solar PV generation at the time of the non-coincident demands and are constrained by upper and lower bounds in recognition of the fact that load factors cannot continue to trend indefinitely.

For each location, Western Power prepares both non-coincident and coincident maximum demand forecasts as above. The whole of network maximum demand forecast derived from the sum of zone substation forecasts is shown in Table 10.

Table 10 Maximum demand (MW)

Actuals	2012/13	2013/14	2014/15	2015/16	2016/17	Average annual growth
Western Power combined network	3,611	3,514	3,605	3,906	3,535	-0.5%

Western Power 2017 forecasts	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 average annual growth
Western Power network POE 10	3,991	3,939	3,951	3,926	3,896	-0.6%
Western Power network POE 50	3,859	3,811	3,792	3,786	3,746	-0.8%

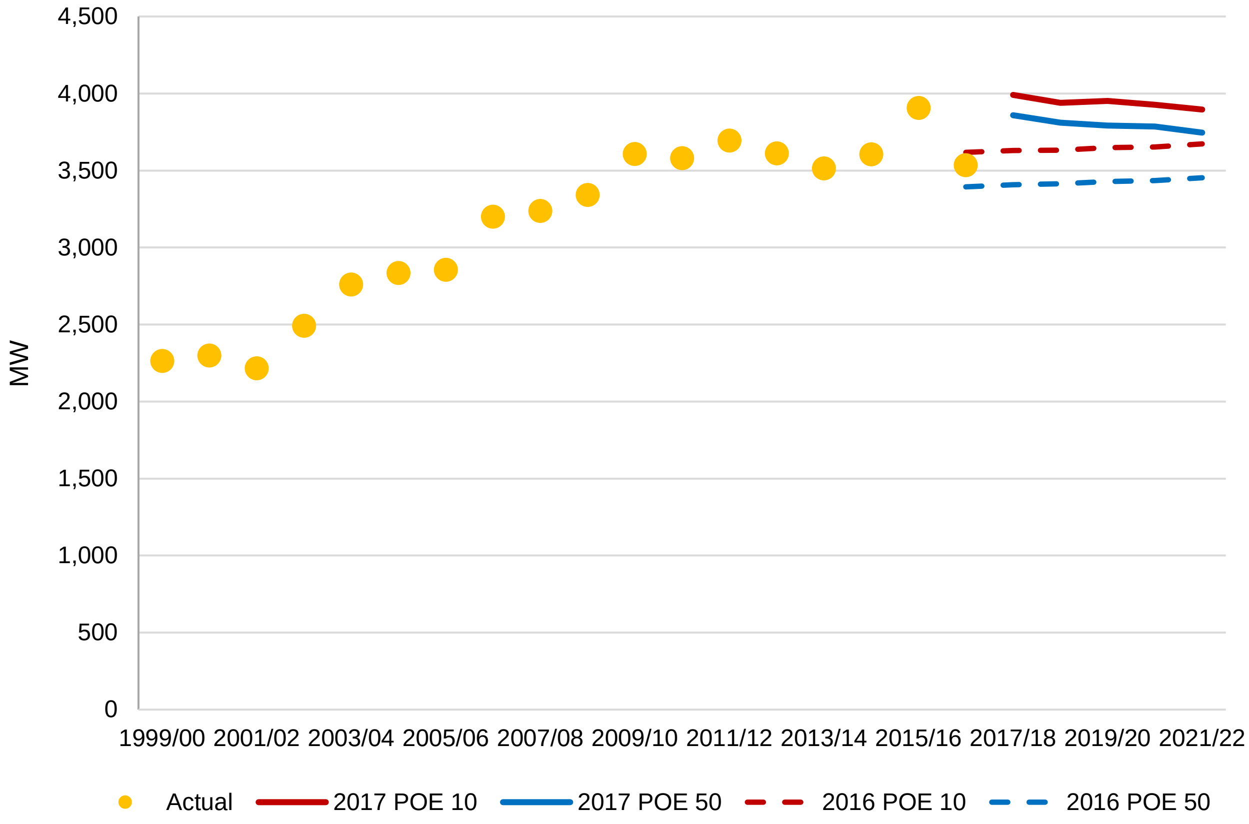
Source: Western Power

6.1.2.1 Forecast comparisons

A comparison between the 2016 and 2017 Western Power network maximum demand forecasts is shown in Figure 13.

At a whole of network level, the falling trend in the demand forecasts appears consistent with the forecast decline in energy consumption and may be explained by forecast falling population and Gross Regional Product growth rates. However the starting point for the 2017 forecast implies a high temperature corrected growth rate in the first forecast year, given that the last two actual observations occurred during an extremely low temperature summer day (in 2016/17) and an extremely high temperature summer day (in 2015/16). It also appears that the difference between the POE 10 and POE 50 forecasts has narrowed, which is in contrast to recent actual maximum demands which if anything have become more volatile.

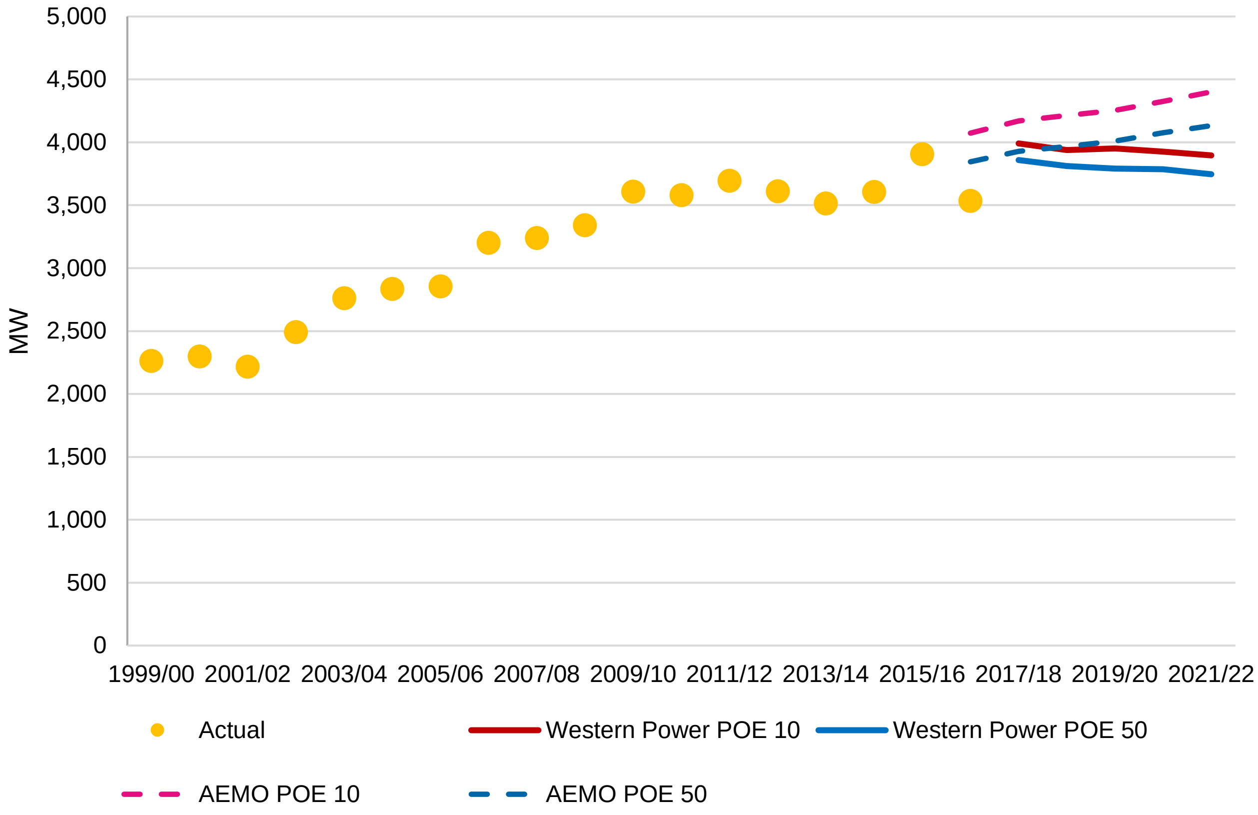
Figure 13 Western Power actual and forecast POE 10 and POE 50 network maximum demand



Source: Western Power data and GHD analysis

A comparison between the 2017 Western Power network maximum demand forecast and Australian Energy Market Operator (AEMO)'s 2017 Statement of Opportunities (SOO) forecasts is shown in Figure 14. AEMO forecasts Southwest Interconnected System (SWIS) generation requirements rather than electricity supplied from Western Power's network and should therefore be consistently higher than Western Power's equivalent forecasts. Notwithstanding, the forecast growth rates are diametrically opposed. It is likely that this difference can be largely attributed to differences in assumptions about future economic growth and in load supplied by distributed solar installations.

Figure 14 Western Power actual and forecast network and AEMO SWIS maximum demand



Source: Western Power and AEMO data and GHD analysis

6.1.2.2 Zone substations+

Western Power shows 2017 summer maximum demand forecasts by zone substation in a series of charts with accompanying commentary. By visual assessment, changes in demand exceeding 10 MW over the entire forecast horizon to 2044/45 occur in just 36 out of a total of 147 substation locations. The majority of these show declining demand, including (in order of greatest fall):

- Cockburn Cement
- Hadfields
- Milligan Street
- Midland Junction
- Padbury
- Welshpool
- Beechbro
- Belmont
- Forrestfield
- Murdoch

- Osborne Park
- Tate Street
- Yokine

Growth substations include (in order of highest growth):

- Meadow Springs
- Hersley Brook
- Hismelt
- Southern River

6.1.2.3 Block loads

As is customary with spatial electricity demand forecasts, block loads and transfers make up significant components of growth in particular locations and at particular times, and are separately added or subtracted from underlying trend growth identified for each zone substation. Western Power has adopted a reasonable, methodical approach to determining the inclusion of planned network connections into the forecasts.

6.1.2.4 Further observations

We offer the following observations on Western Power's approach to forecasting substation maximum demands:

- certain substations are determined to have underlying growth (and are treated as described above) and others are deemed to be 'no growth' loads, based on the single customer nature of those loads
- the projection of historical load factor trends into the future is achieved by a consistent process, however no overriding and intuitive explanation has been provided of the causes of those trends (for example, a changing weather sensitive proportion of demand)
- as energy efficiency trends have not been considered separately, historical improvements which influenced demand growth are implicitly included in the forecasts. This is in contrast to the practice of other utilities which attempt to specifically factor in policies that are designed to increase future energy efficiency
- Western Power has examined the potential impact of the growth of distributed battery storage at a network level only and not at individual locations, and has not considered any significant impact from electric vehicle charging in the next five years
- Western Power has implemented a top down model to validate the existing bottom up approach for the first time in the 2017 forecasts, which is a worthwhile quality control procedure, however there is no published information about the degree of adjustment of the substation forecasts that may have been necessary to reconcile with the top down forecast

Without access to more detailed documentation it is impossible to comment further on these observations. However, none of these issues are likely to be the cause of any significant inaccuracy or bias in the demand forecasts.

The demand forecast model drivers used as inputs and the process itself appear reasonable. We have not seen any examples of specific output on which to make comment on the efficacy of any specific estimated model.

Rather, we have relied on the more in-depth review of Western Power's customer, energy and maximum demand forecast modelling undertaken in 2016 by NIEIR to assume that:

- the models and processes used to prepare the forecasts are as described by Western Power
- the statistical models used are correctly estimated and the results are significant
- spreadsheets, coding and other calculations used invoke the intended outcomes

NIEIR suggested changes to the way in which the demand forecast were prepared in 2016 that may further improve forecast accuracy, which included:

- use of a top-down model to validate the bottom up process
- segmentation of demand into base load and temperature sensitive load
- directly incorporate weather correction into the POE 50 demand forecasts
- improve the solar systems modelling for both energy and maximum demand forecasts
- estimate models based on interval specific maximum demand times where possible

Western Power has advised that it has implemented three of these five recommendations in preparation of the 2017 forecasts. We believe these include the use of a top-down model, segmentation into base and temperature sensitive demand components, and direct incorporation of weather correction. The two remaining refinements yet to be implemented may provide additional confidence in the forecasts but are unlikely to materially change the outcomes.

We accept the Western Power AA4 demand forecast as sound, and reasonable.

7. Benchmarking

7.1 Top down benchmarking

Top down benchmarking can provide an indication of productivity differences between networks.

7.1.1 Benefits of top down benchmarking

Economic benchmarking models can allow for productivity comparisons between networks and for a single network over time. Techniques such as total factor productivity and econometric analysis allow for inter-network comparisons to be made by incorporating multiple outputs and inputs into a single productivity score. In the case of index based approaches (total and partial factor productivity indexes), this can take the form of productivity scores over time whilst for econometric models this takes the form of a single productivity score over the benchmarking period.

Top down benchmarks enable comparisons to be made without the need for exhaustive reviews of individual expenditure categories (what has been termed the 'engineering approach' focusing on comparisons of single activities or programs between businesses and expert opinion). Aggregate benchmarks incorporating multiple outputs are particularly useful when benchmarking Australian electricity networks where using a single output as the cost driver can influence the results significantly. For example, a rural network using an OPEX per km benchmark will appear efficient relative to urban networks whilst using a customer-based metric often reverses the results.

In addition, if networks employ different accounting policies, cost allocation methodologies or outsourcing approaches it can often be misleading to benchmark single activities (such as line maintenance) as costs may be shared, disaggregated or allocated using different assumptions. A good example of this can be found in the Category Regulatory Information Notice (RIN) data, published annually by the AER, in which often large amounts of expenditure are lumped into an 'Other' category.

The use of an econometric or index based approach allows multiple outputs such as customer connections, line length and peak demand to be aggregated based on their influence on network costs and a single productivity score obtained for each network.

We believe that the use of economic benchmarking should complement engineering expertise to produce a range of plausible productivity estimates and provide information at an aggregate level on how networks are performing relative to each other. This view was shared by the Australian Competition and Consumer Commission (ACCC) that "… *benchmarking should initially be used as an informative tool rather than a determinative one. For example, it can be used as a starting point for a conversation with regulated utilities about the level of operating and/or capital expenditures being incurred and proposed. A more sophisticated application could emerge over time.*"[19]

7.1.2 Limitations of top down benchmarking

Whilst top down benchmarking is a useful tool in identifying productivity differences between networks, it also has a number of limitations, particularly in the context of electricity network benchmarking. The most significant limitation is that, despite extensive research, the industry has still to agree on what constitutes the 'outputs' and 'inputs' of an electricity network (distribution or transmission). For example, depending on which

[19] ACCC/AER, *Working Paper– Benchmarking Opex and Capex in Energy Networks*, No. 6, May 2012, p. 14

research is referred, circuit length might be modelled as an input or output producing much different productivity estimates.

Another limitation to top down benchmarking is the inference of efficiency from the productivity scores generated by benchmarking models. In an industry as heterogeneous with a small number of participants, as the Australian electricity supply industry, it is likely that networks each face their own cost challenges that are to a large extent consequences of historical investment decisions made under a different regulatory framework. In order to identify genuine efficiency differences between networks, like-for-like comparisons should be made by normalising for environmental factors beyond the control of a network's management. The AER has acknowledged this limitation of economic benchmarking and has engaged consultants to identify the impact of operating environment factors (OEF) among NEM participants and their influence on productivity scores. We anticipate the results of this investigation will be relied upon in the next round of regulatory determinations in 2018.

In addition to the limitations mentioned, the variability of results possible given the choice of benchmarking technique (stochastic frontier analysis, least squares estimation, corrected ordinary least squares, an index based approach or data envelopment analysis), the model specification used (generally Cobb Douglas or Translog) and the time period used means that often there are a wide range of results. We are of the opinion that a combination of benchmarking models should be used to provide a range of plausible benchmarking results when informing regulatory decision-making.

7.1.3 Australian Energy Regulator benchmarking

The AER has relied on a number of different benchmarking models for use in the most recent round of regulatory determinations and Annual Benchmarking Reports.

Whilst capital and total factor productivity benchmarks are presented in Annual Benchmarking Reports, OPEX has been the focal point of the AER benchmarking, particularly for use in regulatory determinations.

The techniques and model specifications used for distribution and transmission benchmarking, as well the AER application of these models, are provided in more detail below.

7.1.3.1 Total and partial factor productivity (MTFP and MPFP)

Total and partial factor productivity indexes have been used by the AER to benchmark both distribution and transmission networks. A characteristic of MTFP and PFP indexes is that benchmarks can obtained with a small number of observations in contrast to the large datasets required for the estimation of econometric models. This has made index-based benchmarks more appealing because Australian datasets do not require augmentation with Ontario and New Zealand businesses as has been the case for the econometric based benchmarks. The index approach uses estimated weights to combine multiple outputs (or inputs) into a single output (input) index. The ratio of these indexes (output / input) is then used to compare networks against their peers and themselves over time. The Tornqvist index is used by the AER to aggregate the respective input and output indexes[20].

Total and partial factor productivity scores are therefore weighted averages of outputs divided by the weighted average of inputs with the weights either derived from their share of total costs (inputs) or estimated from their influence on costs (outputs).

[20] Ibid., refer p. 38 for specific information relating to use of Tornqvist index to aggregate inputs and outputs

The outputs and inputs[21] currently used by the AER for benchmarking distribution and transmission networks are detailed in Table 11 and Table 12. The OPEX partial factor productivity estimates are obtained using the ratio of the output index to a networks OPEX i.e. OPEX is used as the only input whilst capital partial factor productivity estimates exclude OPEX and consider the ratio of outputs to capital inputs.

Table 11 Distribution MTFP model specification

Input/Output	Variable
Inputs	OPEX
	Overheads MVA-kms >=33kV
	Overheads MVA-kms < 33kV
	Underground MVA-kms >=33kV
	Underground MVA-kms < 33kV
	Transformer capacity MVA (excluding first stage where two stages are required)
Outputs (weights)	Customer numbers (45.8%)
	Circuit length (23.8%)
	Ratcheted peak demand (17.6%)
	Energy throughput (12.8%)
	Customer minutes off supply (a negative weight calculated using VCR)[22]

In this analysis, we have relied upon the latest model endorsed by the AER[23] to produce comparisons with the Western Power transmission network. We have excluded consideration of Energy Not Supplied from the output index as we have been unable to form an historic estimate of this variable for the Western Power transmission network. It is important to note that the model used by the AER in its previous regulatory determinations included voltage weighted connections as an output instead of customer connections.

The revised output specifications in the current transmission model specification are detailed in Table 12.

Table 12 Transmission MTFP model specification

Input/Output	Variable
Inputs	OPEX
	Overhead MVA-kms
	Underground MVA-kms
	Transformer capacity
Outputs (weights)	Circuit length (38%)
	Energy throughput (23%)
	Customer connections (20%)

[21] Input weights are calculated using the annual user cost of capital for capital inputs and the share of total costs for OPEX

[22] State-based Value of Customer Reliability estimates from the AEMO are used to form a negative output weight

[23] AER, *Position Paper: AER Review of Economic benchmarking of Transmission Network Service Providers*, 10 August 2017

Input/Output	Variable
	Ratcheted peak demand (19%)
	Energy not supplied

7.1.3.2 Stochastic frontier analysis (SFA)

SFA has been the technique favoured by the AER to estimate the base year OPEX for distribution networks in previous revenue determinations. SFA uses the maximum likelihood estimation to model the relationship between a dependent variable (OPEX) and explanatory variables (circuit length etc.). An efficiency score is obtained by making assumptions regarding the distribution of the modelled error term and separating network inefficiency (ui) from random noise (vi). Cost efficiency is then calculated as exp(ui).

The model used by the AER uses customer numbers, circuit length, ratcheted maximum demand, the share of underground network, year and a dummy variable for Ontario and New Zealand to estimate distribution network OPEX. The model takes a Cobb Douglas form and is displayed below.

Equation 1 SFA calculation

$$lnOpex = \alpha + \ln(CustNum) + \ln(CircLen) + \ln(RMDemand) + \ln(ShareUG) + Year + NZ + Ontario + vi + ui$$

where:

vi is assumed to be normally distributed,

ui is assumed to have a truncated normal distribution.

ln indicates the natural log of the variable

Having estimated an industry OPEX model, efficiency estimates are generated for each DNSP. The SFA model assumes that there is one efficiency score for each DNSP for the whole benchmarking period. This average efficiency score is then applied to a network's average OPEX over the period, which is then trended forward to the final benchmarking year using the models predicted coefficients.

7.1.3.3 Ordinary least squares (OLS)

Cobb-Douglas and Translog models are estimated using the ordinary least squares approach. With SFA being the primary technique utilised by the AER, the two OLS models have been used as evidence supporting the results derived from SFA and OPEX PFP benchmarking. OLS is different to SFA in that it assumes the error term is normally distributed (it does not split the error term into a random noise and inefficiency component). Efficiency estimates are then derived using dummy variables for each of the businesses in the analysis.

The Cobb-Douglas model specification is included below. The Translog model is similar but also includes squared and cross product terms in the equation.

Equation 2 OLS calculation

$$\ln(Opex) = \alpha + \ln(CustNum) + \ln(CircLen) + \ln(RMDemand) + \ln(ShareUG) + Year + NZ + Ontario + Ausgrid + CitiPower + Endeavour + Energex + Ergon + Essential + Jemena + Powercor + SA\ Power + AusNet\ Services + TasNetworks + United\ Energy + vi$$

Once the model has been estimated the estimated coefficient for each of the network dummy variables can be used to calculate an average efficiency score over the period. Like the SFA approach, efficient OPEX over the period is then trended forward to the final benchmark year to get an OPEX estimate.[24]

7.1.3.4 The influence of the comparison point and operating environment factors

Each of the techniques outlined above can be used to provide a network specific productivity score over the benchmarking period. The next stage in inferring an efficient level of OPEX given the productivity score is to convert it to a score relative to the selected frontier. The econometric benchmarking[25] used by the AER indicated significant differences in the productivity scores between the distribution networks. For example, using the Least Squares Estimator (LSE) Translog model, Powercor was estimated to be the frontier network with an efficiency score of 1.00 and ActewAGL the least efficient with a productivity score of 0.32. Had the AER used these results to adjust average OPEX levels, the OPEX for ActewAGL would have been reduced by 68%. The AER decided against applying such a large reduction and opted to lower the frontier point[26] from which efficiency scores were determined; ruling that "*… we have decided that, on balance, a more appropriate benchmark comparison point is the efficiency score for the business at the upper third (top 33 per cent) of companies in the benchmark sample (represented by AusNet Services). It reduces the benchmark comparison point from 0.86 (used in the draft decisions) to 0.77. We have done this because:*

- *this recognises that more than a third of the service providers in the NEM, operating in varied environments, are able to perform at or above our benchmark comparison point. We are confident that a firm that performs below this level is therefore spending in a manner that does not reasonably reflect the OPEX criteria. An adjustment back to this appropriately conservative point is sufficient to remove the material over-expenditure in the revealed costs while still incorporating an appropriately wide margin for potential modelling and data errors for the purposes of forecasting*
- *given it is our first application of benchmarking, it is appropriate to adopt a cautious approach*
- *our draft decision averaging approach produced an unusual result for service providers ranked in the top quartile of efficiency scores, but below the average of that top quartile. These service providers would require an efficiency adjustment to reach the average benchmark comparison point (because their scores are below the average) despite being efficient enough to be ranked in the top quartile and, hence, included in the average*
- *we consider this approach better achieves the NEO and RPP because it is sufficiently conservative to avoid the risks associated with undercompensating the service provider but also promotes efficiency incentives.*"[27]

The impact of the AER's decision to lower the comparison point was that the 5th placed DNSP (AusNet Services) was used as the frontier rather than the network with the highest productivity score.

Aside from the lowering of the comparison point, the AER also introduced operating environment factors to account for factors beyond the control of networks that influenced costs and therefore would bias efficiency estimates. The concept of OEFs was to adjust efficiency scores in circumstances where a network

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[24] For more information on econometric techniques used by AER, refer Economic Insights report *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*

[25] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014

[26] The frontier represents the comparison point from which a network is compared. An efficiency score is generated by comparing the distance between the selected comparison point and a network's own score.

[27] AER, *Final Decision - Ausgrid distribution determination 2015/16 to 2018/19: 7-61 Attachment 7 – Operating expenditure,* April 2015, p. 7-61

experienced exogenous factors that weren't relevant to the comparator network (AusNet Services). The impact of these OEF's was to further reduce the range in productivity scores between the businesses.

7.2 Western Power benchmarking submission

Western Power has submitted its own benchmarking report titled 'Western Power Productivity Performance' which outlines its benchmarking performance between 2006/07 and 2015/16.

Whilst there are similarities between many of our benchmarks and those used in the Western Power benchmarking report, there are a number of key differences. We have relied upon historic performance data[28] provided by Western Power for its distribution and transmission networks, but not the data used for other networks.

Without the entire dataset it is, in some circumstances, difficult to provide an explanation of why the benchmarking results could differ so markedly. It should be noted that we believe the Western Power report is likely to have been supplemented using publicly available data prior to the AER's release of its 2017 Annual Benchmarking Report.

The 2017 AER Annual Benchmarking Report includes a number of adjustments to historic data that are likely to have been unavailable to Western Power at the time their productivity performance report was written. In the case of networks that could be considered comparators to Western Power, such as Ergon Energy and Powercor, there have been significant revisions to historic data either due to cost allocation changes or updated MVA ratings for network assets. Differences between our results may also be due to different model specifications used by Western Power in its benchmarking report. Where our results differ from Western Power's own benchmarks, we have endeavoured to explain the differences.

7.2.1 Distribution benchmarks

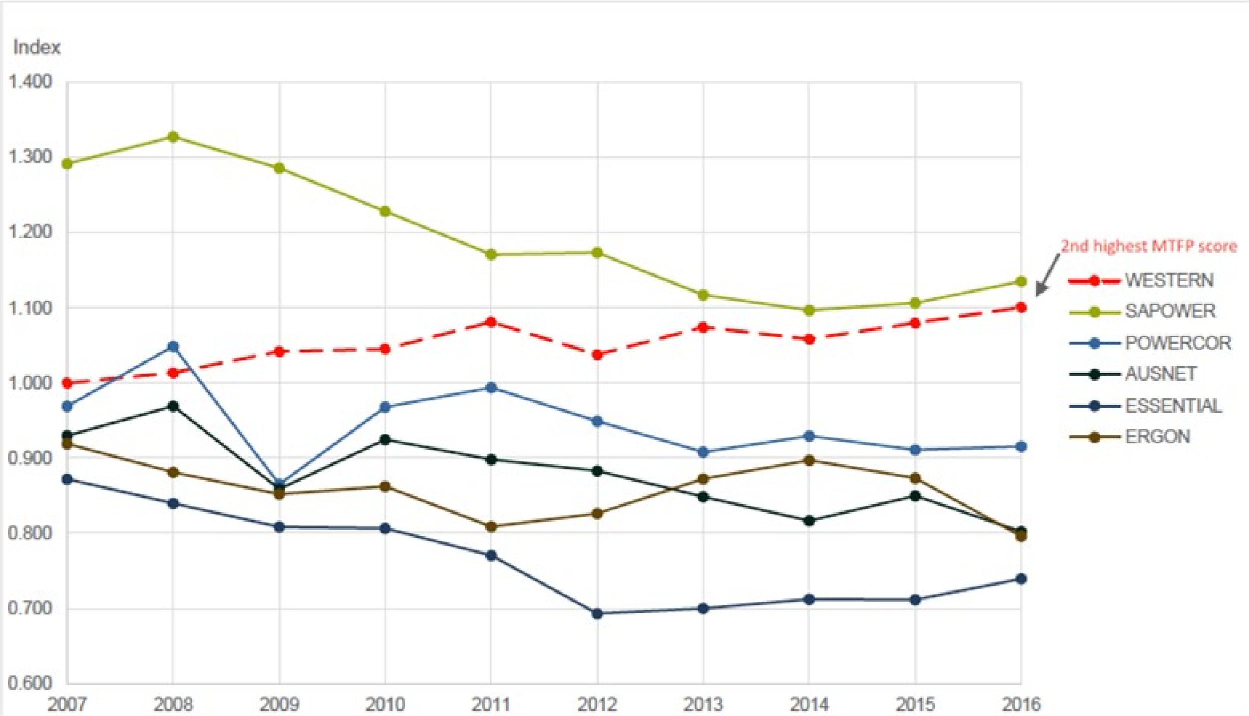
Western Power's benchmarking report asserts that in 2016 the Western Power distribution network has the 2nd highest total factor productivity score, the 4th highest OPEX PFP score and the highest capital PFP score among the other predominantly rural networks[29]. The following figures are extracts from the Western Power report.

[28] Western Power Excel model *Synergies - WP input data for benchmarking report - 10 Oct 2017*

[29] These are SA Power Networks, Powercor, AusNet Services, Essential Energy and Ergon Energy. We have also included TasNetworks in our own benchmarks.

Figure 15 Western Power AA4 submission - MTFP results

MTFP results for Western Power's closest NEM DNSP peers – 2006-07 to 2015-16

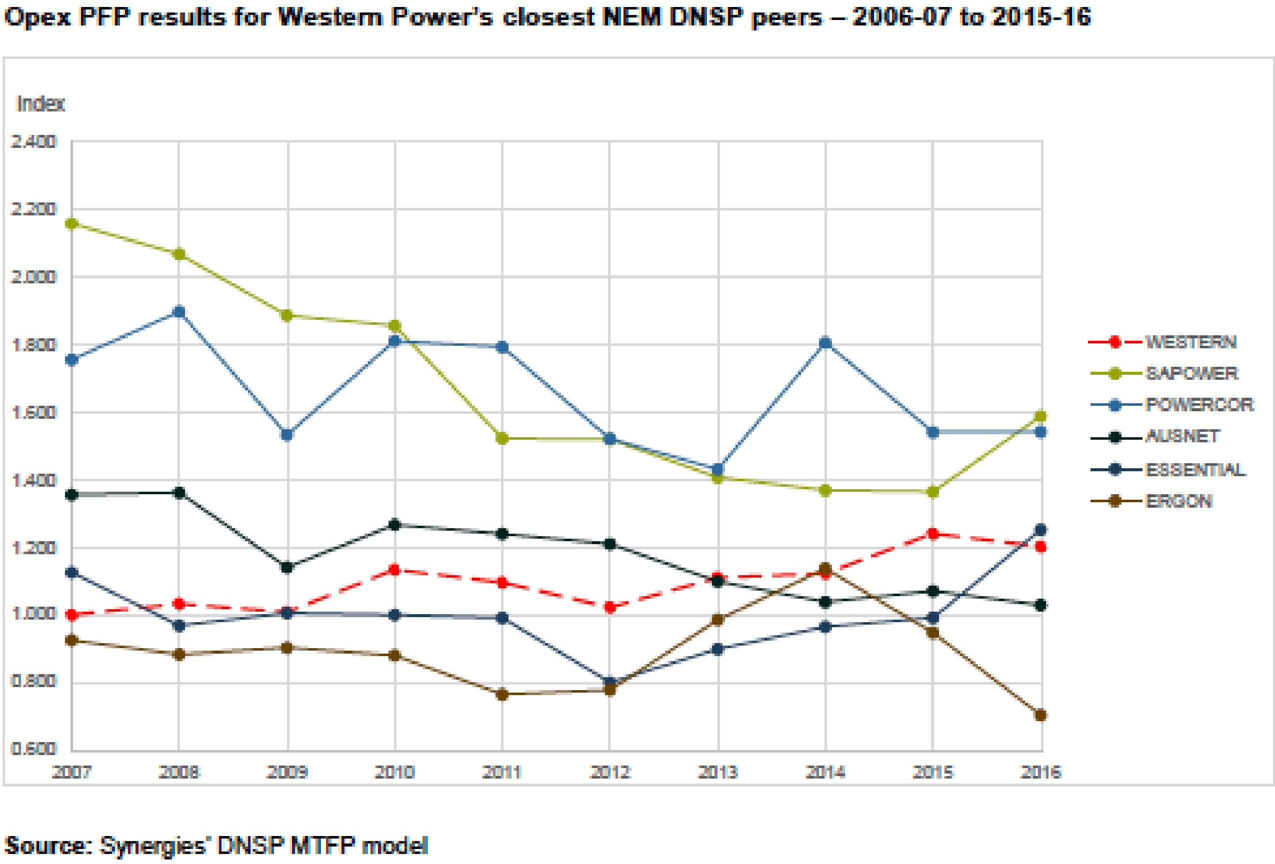


Source: Synergies' DNSP MTFP model

Figure 15 shows total factor productivity over time. Western Power's performance is shown as having improved over time and the distribution network was ranked 2nd behind SA Power Networks in 2016.

By contrast, our construction of the AER's current MTFP model (using the output and input specifications as shown in Table 11 and Table 12) produces different results, with Western Power ranking 4th out of the 6 comparator networks. Whilst some of these differences may be explained by recent data updates, available publicly since November 2017, these changes are unlikely to result in such a significant difference in benchmarking results. To identify what is driving differences in our own benchmarks and those presented above, we have compared the OPEX PFP and capital PFP results (given the total factor productivity score is a weighted average of these two indexes).

Figure 16   Western Power AA4 submission - OPEX PFP results



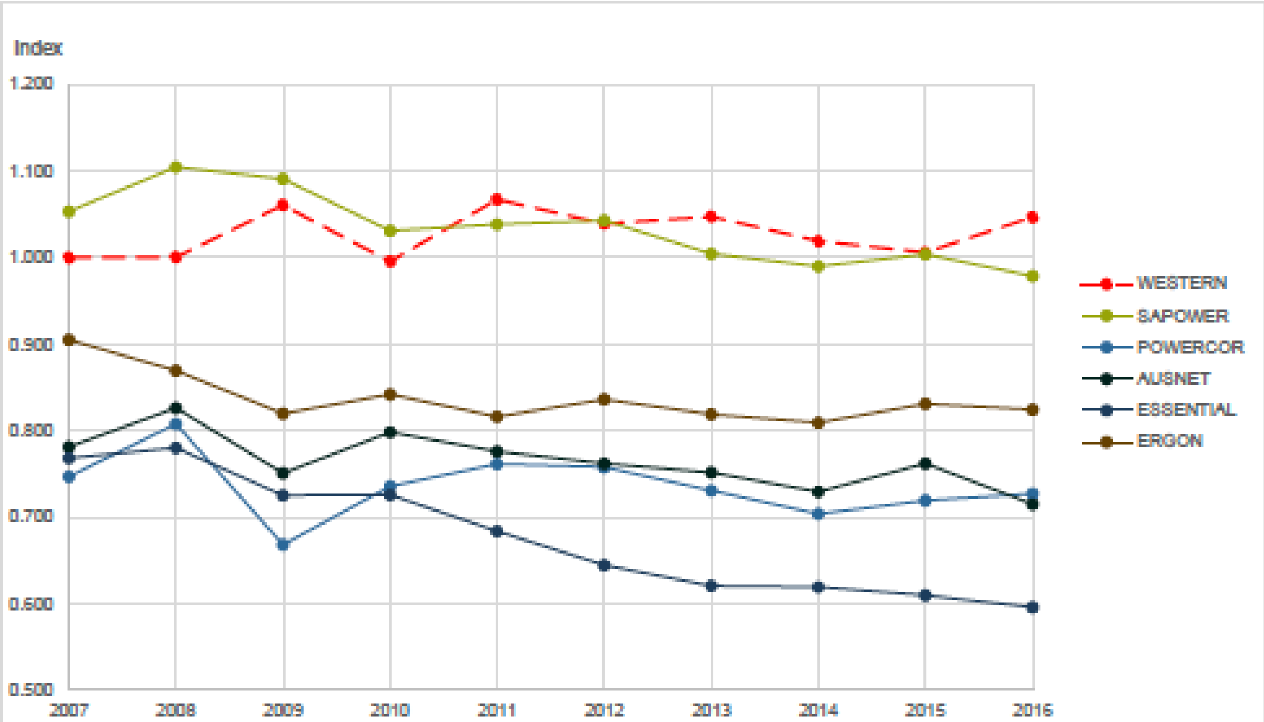
Our own OPEX benchmarks are similar to those presented above in the Western Power report; however, there are a couple of key differences, particularly with the performance of Powercor and Ergon Energy since 2014. Despite these differences, the Western Power OPEX benchmarking results are broadly similar particularly against SA Power Networks who are used as a comparator network in this report.

From Figure 16, the Western Power productivity score in 2016 is approximately 1.2 compared to SA Power's 1.6, which represents an efficiency score of 75%. Our own benchmark has Western Power with a score of 1.24 compared with SA Power's 1.65 which gives a comparable efficiency score of 75.2%.

Differences in Powercor and Ergon Energy's OPEX partial factor productivity scores are likely to be driven by changes in the AER benchmarking dataset, released with the 2017 Annual Benchmarking Report. With this in mind, we believe the differences in the two sets of total factor productivity results is due to difference in the capital partial factor productivity results.

Figure 17 Western Power AA4 submission - CAPEX PFP results

Capex PFP results for Western Power's closest NEM DNSP peers – 2006-07 to 2015-16



Source: Synergies' DNSP MTFP model

The capital PFP results presented above[30] suggest Western Power is ranked 1st among comparator networks in 2016.

There are fairly significant differences between these results and our own using the AER's current model specification (refer Figure 20). Whilst the Western Power report indicates a capital productivity score that is similar to SA Power Networks over the period, our model indicates that Western Power is more closely aligned to Essential Energy and was ranked 5th in 2016.

Without having access to the supporting data used to construct the capital benchmarks, it is difficult to identify the reasons behind the differences. Our own benchmarks for total factor productivity, OPEX partial factor productivity and capital productivity are presented below. TasNetworks as a predominantly rural distribution network has also been included in the analysis.

[30] Synergies Economic Consulting, *Western Power's productivity performance*, September 2017, p. 7

Figure 18 Assessed Total Factor Productivity 2007-2016

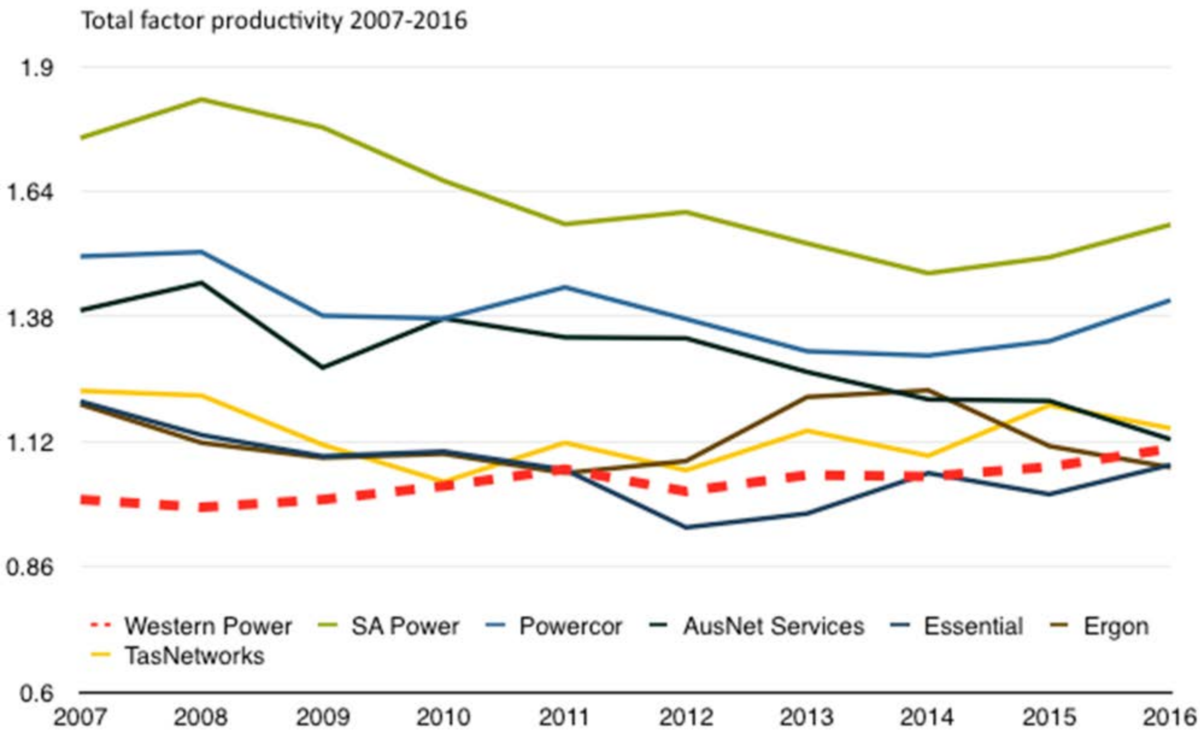


Figure 19 Assessed OPEX Partial Factor Productivity 2007-2016

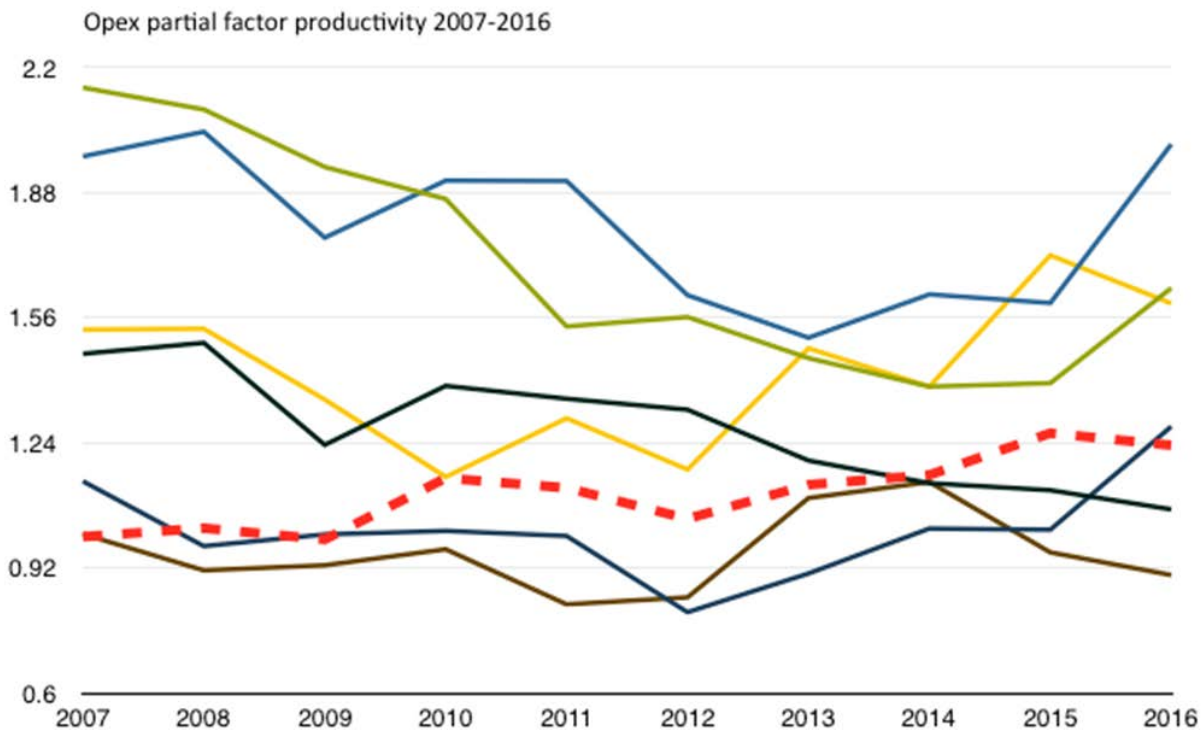
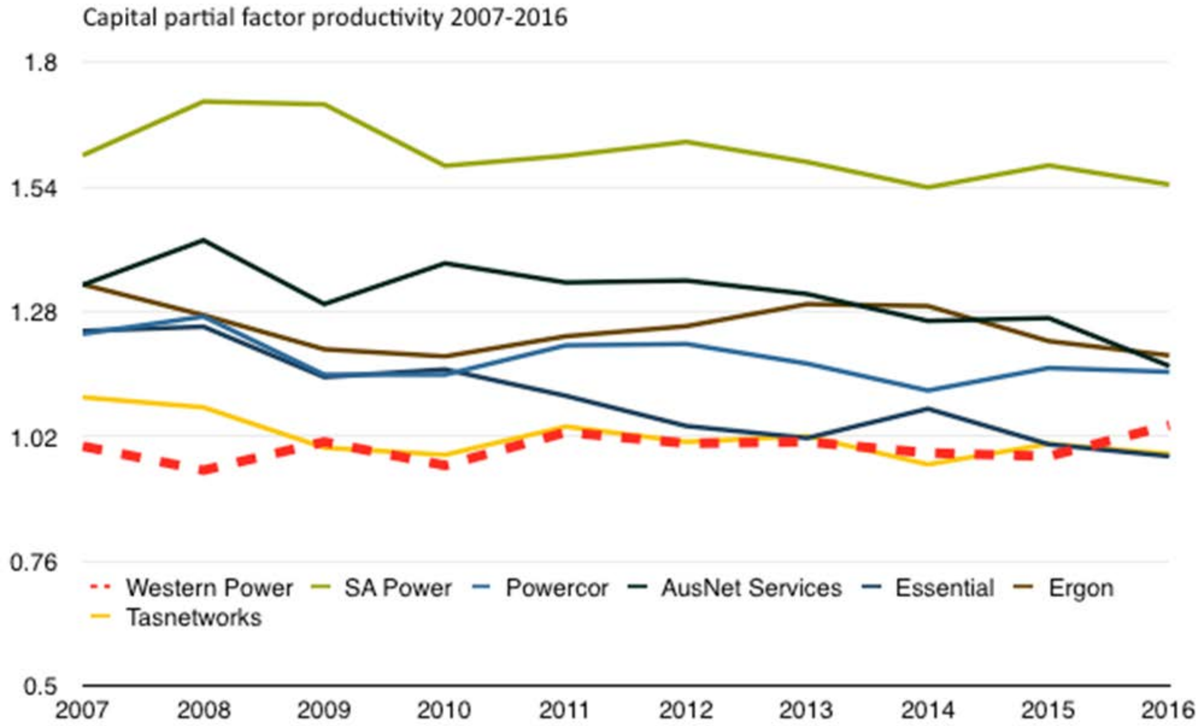


Figure 20 Assessed Capital Partial Factor Productivity 2007-2016



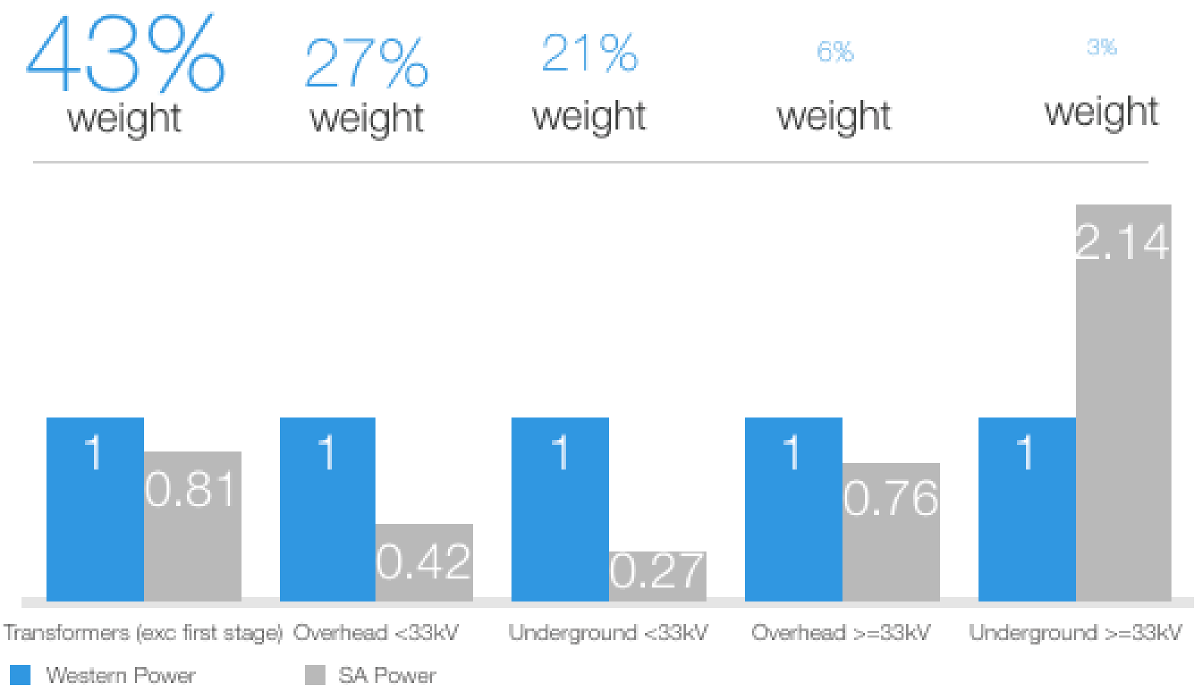
The relatively low productivity score for Western Power for the capital benchmarks is due to the significant presence of overhead 22 kV lines in its network and the aggregation of MVA-km in the AER's total factor productivity model. By separating MVA-km into distribution and transmission components, Western Power has significantly higher inputs (in terms of distribution MVA-km) than its peers. Figure 21 shows the composition of inputs along with the associated input weights (industry average) for SA Power Networks and Western Power. With overhead and underground distribution network (i.e. assets at or below 33 kV) comprising almost half of the capital input index, Western Power has significantly higher values for these inputs than SA Power Networks.

In 2016, Western Power had an output index that was about 17% greater than SA Power Networks. In the context of productivity benchmarking, this means that if Western Power's aggregated inputs were approximately 17% greater than SA Power Networks, then the utilities would have a similar productivity score. However, the comparison of capital inputs below shows Western Power's capital inputs are much greater then SA Power Networks for all outputs other than underground sub-transmission, which receives a relatively low weight in the input index.

We do not suggest that Western Power's use of capital inputs is inefficient; rather the demarcation of distribution and transmission in the AER's models at 33 kV means that Western Power performs lower because of its high proportion of 22 kV in much the same way that TasNetworks performs lower in the capital benchmarks because it also has a significant proportion of 22 kV assets in its network.

Given the capital productivity inputs are a significant component of total factor productivity estimates, these differences will also have a significant impact on the total productivity estimates in Western Power's Benchmarking Report.

Figure 21 Comparison of network composition



7.2.2 Transmission benchmarks

From their submission, Western Power's transmission benchmarking[31] indicates that Western Power's transmission network is ranked 3rd out of 5 for total, OPEX and capital productivity in 2016.

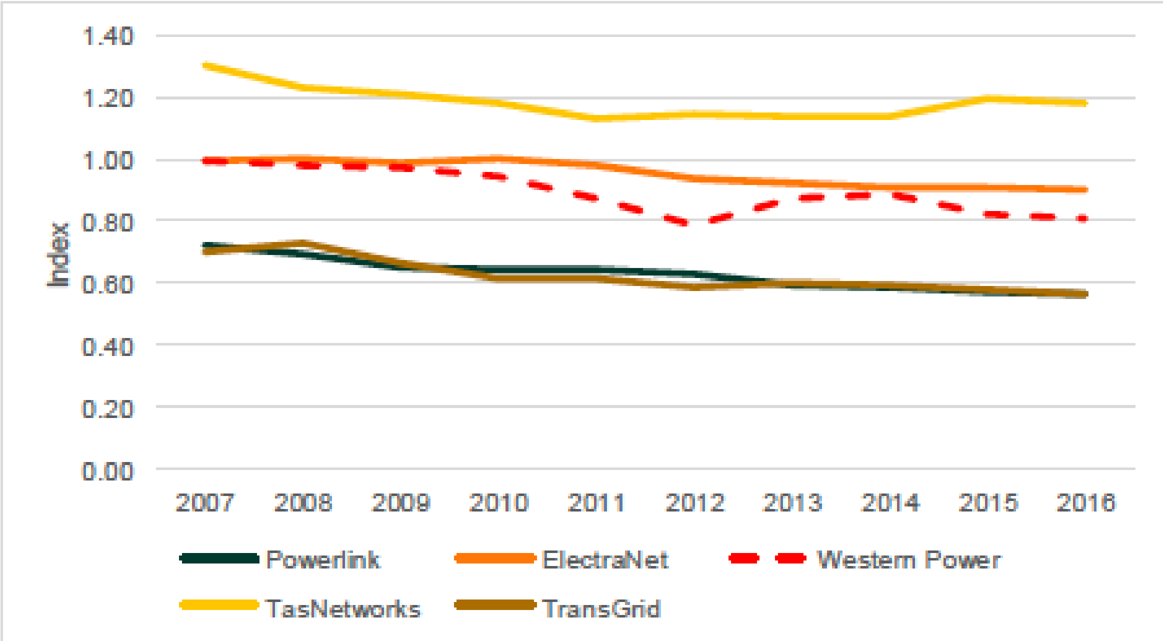
Our comparative benchmarking using industry data and Western Power's transmission information shows Western Power ranked 5th out of 6 (including AusNet Services in our analysis) for total factor productivity, 6th out of 6 for OPEX partial factor productivity and 4th out of 6 for capital partial factor productivity in 2016. We consider the reason for the differences between our own results and those presented in Western Power's benchmarking report is most likely due to the different output specification used.

Whilst Western Power's analysis uses voltage-weighted connections as an output, we have used customer connections at the distribution level as preferred by the AER. This change in output specification meant that that voltage-weighted connection output was replaced by customer connections in the output specification for transmission network benchmarks.

For our analysis, we have used the current AER model specification that includes customer connections and not voltage weighted connections. The results of the MTFP modelling included in the Western Power submission is shown in Figure 22, whilst our comparative MTFP assessment is shown in Figure 23. The change in model specification from voltage-weighted connections to customer numbers has resulted in a narrowing of total factor productivity scores between the larger networks (in terms of downstream customer connections) and the smaller networks.

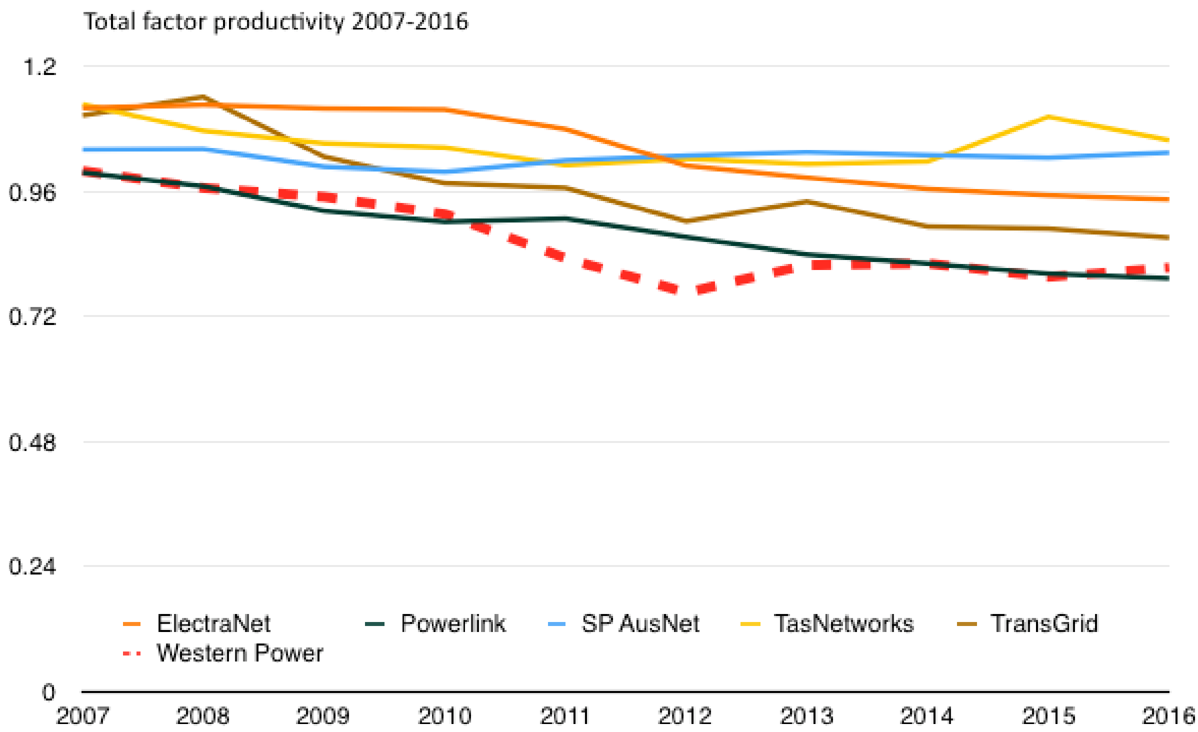
[31] Synergies Economic Consulting, *Western Power's productivity performance*, September 2017, pp. 57-58

Figure 22 Western Power AA4 submission - Transmission MTFP results



Source: Synergies MTFP model

Figure 23 Assessed Total Factor Productivity 2007-2016



7.3 Estimating OPEX in 2016/17 using AER benchmarking approach

7.3.1 Distribution

The steps taken to arrive at a predicted range of $267 million and $287 million for OPEX for the Western Power distribution network in 2016/17 were as follows:

1) Use the Australian Energy Regulator's (AERs) four OPEX models to produce average productivity scores for Western Power (distribution)
2) Adjust the Western Power productivity score relative to SA Power Networks
3) Adjust SA Power Networks operating expenditure to incorporate differences in operating environment
4) Extrapolate predicted OPEX forward to 2016/17

Step 1 - Western Power's productivity scores using the four AER models

For this purposes of this report, Western Power's distribution data[32] has been included in each of the four OPEX benchmarking models used by the AER in the most recent round of determinations and the 2017 Annual Benchmarking Report to measure OPEX productivity differences between distribution networks. These four models are the Stochastic Frontier Analysis model (SFA model), the Least Squares Cobb Douglas Model (Cobb Douglas model), the Least Squares Translog model (Translog model) and the OPEX partial factor productivity model (OPEX PFP model).

Results from the four OPEX benchmarking models are displayed in the table below. Western Power's (distribution) productivity score is between 56% and 61%. These results represent the average productivity score for Western Power (distribution) over the 2007-16 benchmarking period. Western Power's highest productivity score is obtained using the Translog model whilst its lowest productivity score comes from the OPEX PFP model.

The Translog model incorporates squared outputs and cross products of the outputs in the model specification and therefore tends to favour larger networks because their outputs will have a greater influence on the estimated frontier. By contrast, larger networks tend to benchmark less favourably using the OPEX PFP model because reliability, measured in customer minutes off supply, is incorporated as a negative output and larger networks in terms of customer numbers and line length will tend to have a higher number of customer minutes off supply.

Looking at the results below, Western Power is ranked either 9th or 10th over the period depending on which OPEX model is selected.

[32] Western Power Excel model *ERA001 – Synergies – WP input data for benchmarking report – 10 Oct 2017*

Table 13 Comparison of AER productivity model results

Network	SFA model		Cobb Douglas model		Translog model		OPEX PFP model	
	Score	Rank	Score	Rank	Score	Rank	Score	Rank
Powercor	96%	1	100%	1	100%	1	91%	2
CitiPower	91%	2	87%	2	82%	3	100%	1
United	86%	3	80%	4	71%	5	76%	4
SAPower	81%	4	80%	3	84%	2	86%	3
TasNetworks	76%	5	77%	5	71%	6	72%	5
AusNet	75%	6	75%	6	71%	4	65%	8
Jemena	71%	7	65%	7	56%	11	67%	6
Energex	63%	8	61%	9	66%	8	67%	7
[redacted]								
Endeavour	59%	10	55%	11	59%	10	63%	9
Essential	58%	11	63%	8	67%	7	51%	12
Ergon	52%	12	53%	12	53%	12	48%	13
ActewAGL	46%	13	44%	13	40%	14	55%	11
Ausgrid	45%	14	42%	14	47%	13	46%	14

The productivity scores outlined in the table above are relative to the network with the highest productivity score (Powercor for the econometric models and CitiPower for the OPEX PFP model). In the most recent revenue determinations for the Queensland, NSW and ACT networks the AER did not use the network with the highest score as the comparison point but reduced this frontier by using the 5th placed network as the comparison point (AusNet Services at the time). This reduction was to ensure a comparison point that was "*… sufficiently conservative to avoid the risks associated with undercompensating the service provider but also promoting efficiency incentives*."[33]

We agree that a reduction of the frontier point is necessary in the application of the AER's models for Western Power, given:

- Western Power's data is, to our understanding, unaudited and not necessarily prepared in the same manner as the other networks that have been subject to the AER's benchmarking since 2014
- The decision on which network to use as the comparison point should be made with consideration to the availability of information on the different operating environments between networks. That is, if CitiPower or United Energy were to be used as comparator networks, it is unlikely that benchmarks could be normalised accurately to ensure like-for-like comparisons. Choosing a comparator network that operates in a similar environment means the risk of mistaking genuine operating differences with inefficiency is reduced.

[33] AER, *Final Decision - Ausgrid distribution determination 2015/16 to 2018/19: 7-61 Attachment 7 – Operating expenditure,* April 2015

Step 2 - Find a network to use as a comparator for Western Power (distribution)

We have considered two criteria in selecting a comparison distribution network for Western Power:

- select a network that can be considered high performing over the period
- select a network that limits the number of adjustments required to ensure like-for-like comparisons are being made

We believe that using SA Power Networks as the comparison point satisfies both these criteria. In terms of historic performance, the AER's 2016 Annual Benchmarking Report indicated the SA Power Networks ranked between 2nd and 4th over the benchmarking period using the four different OPEX models. With respect to the second condition, we considered each of the predominantly rural networks using a number of different characteristics to identify which network could be considered the most similar to Western Power's distribution network. Four metrics considered are displayed below these are route line length, poles per overhead km, customer density and demand density.

Figure 24 Comparison of distribution network characteristics

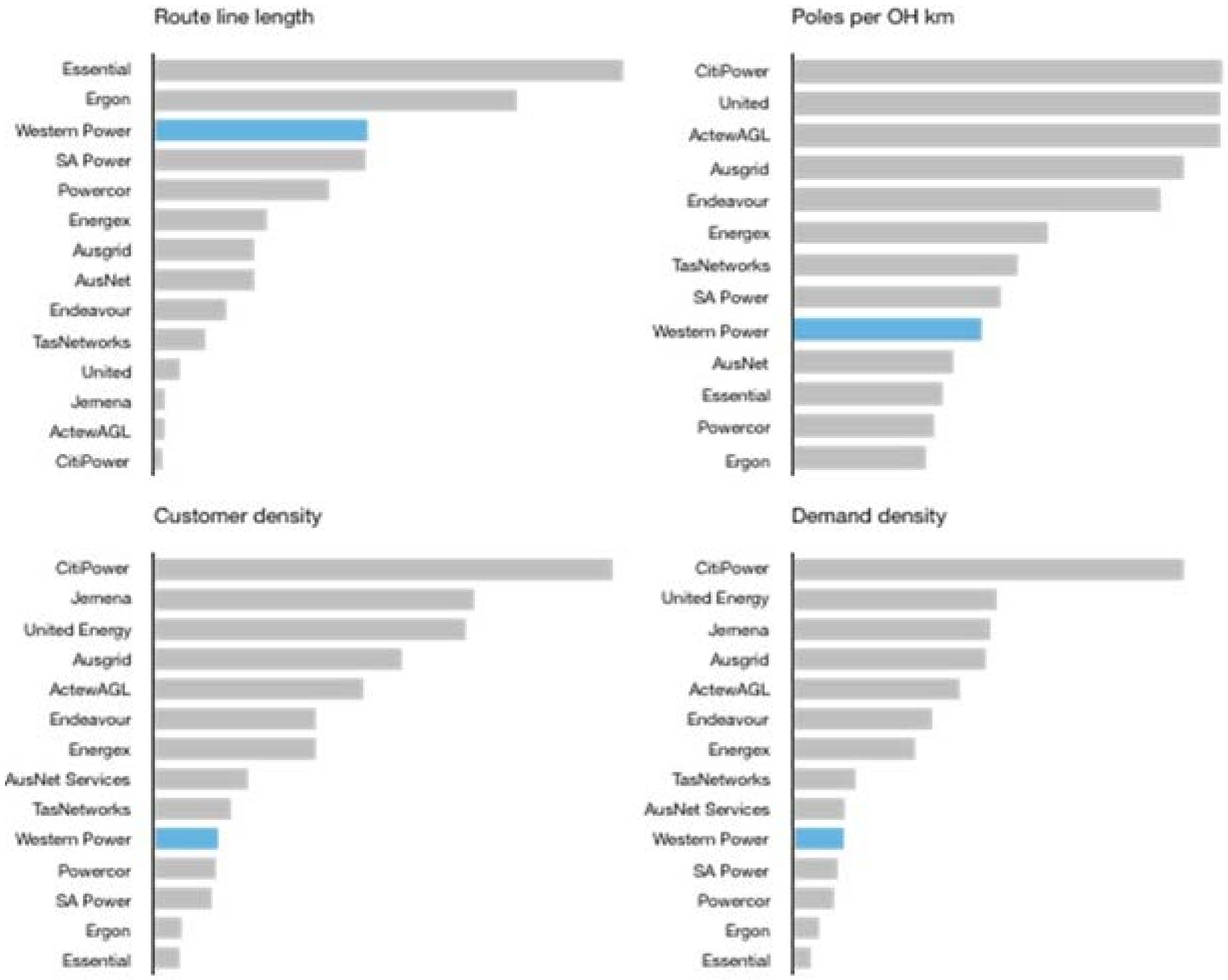


Figure 24 shows that SA Power Networks and Powercor are the most similar to Western Power in terms of route length whilst AusNet Services, TasNetworks, Powercor and SA Power Networks are similar with respect to customer and demand density. AusNet Services and SA Power Networks are the closest comparators in terms of poles per overhead km.

On this basis, in addition to SA Power Networks and Western Power both supplying electricity to a single large city (Adelaide and Perth respectively), we believe SA Power Networks provides the best comparative DNSP against which to measure Western Power's performance over the period.

In addition, the use of SA Power Networks as a comparator will enable a benchmark to be provided for Western Power's network as a whole (distribution and transmission) by combining ElectraNet and SA Power Networks in a state based benchmark. The use of an aggregated distribution and transmission benchmark is important because Western Power operates an integrated network in which investment and operating decisions will be made from the perspective of the system as a whole (both distribution and transmission).

Step 3 - Identification and application of operating environment factors

Environmental factors are network characteristics that influence a network's costs and are beyond the control of a network's management. In the context of the AER's benchmarking, this means any network characteristic, beyond the influence of management, that impacts Western Power's ability to convert inputs (OPEX) into outputs (customer connections, circuit length, energy throughput and ratcheted peak demand). Exogenous cost drivers that are unique to SA Power Networks or Western Power should be quantified if like-for-like comparisons are to be made. The exogenous factors we have considered in this analysis include;

- the use of stobie poles by SA Power Networks
- scale differences between the two networks
- network design differences (particularly the impact of single-wire earth return (SWER) used by SA Power Networks)

i. Stobie pole OEF

The use of stobie poles in South Australia, compared to a pole population in Western Australia that is predominantly wood, are likely to influence pole inspection and maintenance cost differences between the two networks.

Table 14 uses pole inspection data from the publicly available Category RINs to highlight the difference between the SA Power Networks pole inspection cycle and that of other rural networks that do not use stobie poles. We have used pole inspection and population data over a three-year period to illustrate differences between the SA Power Networks pole inspection cycle and that of rural networks.

Table 14 Comparison of network pole inspection and population

Network	Poles inspected / maintained (2014-16)	Pole population (2014-16)	Implied inspection cycle (years)
SA Power Networks	283,613	2,236,412	**7.9**
TasNetworks	161,590	681,160	4.2
Essential Energy	1,022,276	4,140,543	4.1
Ergon Energy	799,501	2,879,957	3.6

Network	Poles inspected / maintained (2014-16)	Pole population (2014-16)	Implied inspection cycle (years)
AusNet Services[34]	254,410	785,276	3.1
Powercor	537,478	1,463,829	2.7
Total (excl. SA Power Networks)	2,775,255	9,950,765	**3.6**

Table 14 calculates the implied inspection cycle by dividing the number of poles inspected over a three-year period with the total number of poles over this period. The implied inspection cycle of rural networks (excluding SA Power Networks) is 3.6 years whilst the inspection cycle for SA Power Networks is approximately 8 years per pole.

Assuming the presence of stobie poles means that SA Power Networks are required to conduct fewer inspections than their peer networks, this will result in reduced OPEX relative to other networks. If an OPEX adjustment is not made then productivity benchmarks are likely to attribute these cost differences to inefficiency. In order to normalise for the impact of stobie poles we have used the pole inspection and maintenance costs from the Category RINs to estimate the average inspection and maintenance costs per pole across the industry. After calculating an average pole inspection and maintenance cost per pole this figure has been multiplied by the SA Power Networks pole population in 2016 to produce an estimate of the SA Power Networks pole inspection and maintenance costs if their pole population was similar to the rest of the industry.

Table 15 Pole maintenance costs

Network	Poles inspection and maintenance costs (2014-16)	Pole population (2014-16)	Unit maintenance costs (average $ cost per pole)
ActewAGL	$ 6,619,120	152,664	$ 43.4
CitiPower	$ 4,105,746	147,361	$ 27.9
Endeavour Energy	$ 33,515,980	1,287,745	$ 26.0
Ergon Energy	$ 68,799,763	2,879,957	$ 23.9
AusNet Services	$ 23,256,703	1,097,561	$ 21.2
Powercor	$ 28,770,469	1,463,829	$ 19.7
Ausgrid	$ 23,273,405	1,527,770	$ 15.2
Energex	$ 16,607,699	1,649,895	$ 10.1
United Energy	$ 6,087,159	645,234	$ 9.4
Essential Energy	$ 34,937,488	4,140,543	$ 8.4
TasNetworks	$ 5,688,890	681,160	$ 8.4
SA Power Networks	$ 17,104,367	2,236,412	$ 7.6
Industry Average (excluding SA Power Networks)			**$ 16.1**
Rural Average (excluding SA Power Networks)			**$ 15.7**

[34] AusNet Service 2014 and 2015 Category RIN data has been used, AusNet's 2016 Category RIN suggests every pole in the network was inspected twice and has therefore been excluded

Between 2014-16, SA Power Networks had the lowest maintenance and inspection OPEX per pole of the NEM networks. Using the average maintenance cost per pole across the industry ($16.1) and for the rural networks ($15.7) it appears that average pole inspection and maintenance costs have been higher for other networks than for SA Power Networks. In order to incorporate these unit costs into an OPEX figure we have weighted the respective unit costs using the following methodology.

SA Power Networks customer density (2014-16) = 9.67

Industry customer density (2014-16) = 13.42

Rural networks customer density (2014-16) = 6.93

Respective weights to match SA Power Networks customer density = 42% Industry, 58% Rural networks

Weighted unit cost = (0.42)*16.1 + (0.58)*15.7 = $15.87 per pole

SA Power Networks number of poles in 2016 = 745,696

Implied maintenance and inspection for poles = $11,832,657

Actual pole inspection and maintenance in 2016 = $6,316,534

OEF adjustment = **+ $5.5 million**

ii. Scale difference OEF

We chose SA Power as the comparison network because of the similarities between the Western Power distribution network and that of SA Power Networks, including the route line length of the two networks.

Recent AER benchmarking has suggested that Australian networks operate under relatively constant returns to scale (i.e a 1% increase in combined output results in a 1% increase in OPEX) this had been derived from the coefficients of the three econometric models employed by the AER with output being the combined output of customer numbers, circuit length and ratcheted peak demand. These are;

- The SFA model - a 1% increase in output results in a .993% increase in OPEX,
- The Cobb Douglas model - a 1% increase in output results in a 1.02% increase in OPEX, and
- The Translog model - a 1% increase in output results in a .973% increase in OPEX.

We believe that SA Power and Western Power (distribution) do not operate at such different scales that an operating environment adjustment for scale differences is required.

OEF adjustment = **$0**

iii. Network design OEF

Whilst SA Power Networks and Western Power (distribution) are similar, relative to other Australian networks, in terms of line length and poles per overhead km there are significant differences in the line voltages operated by each network, indeed this is one of the reasons Western Power’s capital productivity is below SA Power Networks in the AER’s index benchmarks.

In 2016, the SA Power Networks average MVA rating per route km was 2.6 whilst Western Power's was 4.6 - this is driven in large part by SA Power Networks' large proportion of overhead SWER and Western Power's high proportion of overhead 22 kV lines.

Table 16 highlights the overhead line voltage differences between the two networks in 2016.

Table 16 Comparison of network characteristics

Overhead	SA Power Networks		Western Power	
	Circuit km	Proportion of total	Circuit km	Proportion of total
Overhead SWER	29,136	41%	0	0%
Overhead low voltage distribution	18,909	27%	9,197	13%
Overhead 6.6 kV - 11 kV	17,876	25%	625	1%
Overhead 22 kV - 33 kV	3,962	6%	58,357	86%
Overhead 66 kV[35]	1,439	2%	0	0%
Total	**71,322**	**100%**	**68,179**	**100%**

As Table 16 illustrates, most of Western Power's network operates at a voltage between 22 & 33 kV whilst the SA Power Networks network comprises a significant amount of SWER, low voltage and overhead lines below 11 kV. These differences in overhead line voltages are likely to result in different cost outcomes with respect to asset maintenance with higher voltages driving higher maintenance costs. In addition, SA Power Networks has network assets at 66 kV, which Western Power would classify as transmission.

In order to make a like for like comparison between the cost outcomes of SA Power and Western Power an adjustment should be made to the SA Power Networks maintenance OPEX to account for the cost advantages associated with maintaining a network with significant low voltage and SWER assets and also the increased costs incurred operating 66 kV assets.

To estimate an appropriate OEF we have assumed that maintenance expenditure per km is proportionate to the replacement cost per km of overhead lines. The per km replacement costs and associated relative costs that have been used to estimate a maintenance OEF are presented below.

Table 17 Comparison of overhead line costs

Voltage	Replacement cost ($/km)	Relative cost difference
SWER	45,600	1.0
Low Voltage	152,000	3.3
11 kV - 22 kV	190,000	4.2
33 kV	264,000	5.8
66 kV	330,000	7.2

The relative cost differences from the table above have been used to estimate the increased maintenance costs SA Power would incur if its network operated at voltages similar to Western Power. The relativities from the table indicate that a km of low voltage network is 3.3 times more costly to maintain than a km of SWER whilst 11-22 kV assets are around 4 times more costly to maintain per km.

Applying these relativities suggests that SA Power's maintenance OPEX in 2016 would be $21.5 million rather than the $14.4 million incurred in 2016. This represents an OEF of $7.1 million in 2016.

OEF adjustment = **+ $7.1 million**

[35] 66 kV assets are regarded as transmission assets for Western Power in accordance with the Access Code 2004 definition

iv. Operating environment factor summary

Two OEF's totalling $12.6 million have been added to the SA Power Networks OPEX to adjust for differences in network design and asset types between the two networks. We note that there are OEFs that are likely to favour Western Power relative to SA Power Networks - particularly the economies of scope attained through the sharing of corporate overheads between distribution and transmission networks and costs incurred by SA Power Networks associated with retail contestability in the South Australia. Without Western Power's disaggregated historic OPEX data it is difficult to examine the cost benefits Western Power might incur from these economies of scope and the absence of full retail contestability.

Step 4 - Extrapolate the Western Power's OPEX to 2016/17

Using the AER's four OPEX benchmarking models, Western Power's (distribution) predicted OPEX in 2015/16 is between $263 million and $283 million. Predicted OPEX for each model as well as the steps taken to arrive at the estimate are detailed below.

For the OPEX PFP model a single productivity score is available each year, this means that converting the productivity score into a dollar estimate is obtained by multiplying the productivity score by Western Power's OPEX in 2015/16. For the three econometric models, the efficiency score represents the average productivity score over the period, this is then converted into a 2015/16 OPEX estimate by trending average efficient OPEX forward to 2015/16 using the coefficients from the estimated cost function.

Table 18 Predicted 2015/16 OPEX from AER modelling

OPEX model	Average efficiency relative to SA Power	Efficiency after OEF adjustment	Predicted OPEX in 2015/16
OPEX PFP	75%	80%	$262.8 M
SFA model	73%	77%	$283.0 M
Cobb Douglas model	71%	75%	$271.2 M
Translog model	72%	77%	$276.4 M

Publicly available data for distribution networks is available through to 2016, which means the OPEX estimated by each of the models are for 2015/16. In order to extrapolate forward to 2016/17 we have used the growth in Western Power's outputs (customer numbers, circuit length and ratcheted peak demand) and multiplied them by the respective coefficients from each of the models. The growth rate in the price index has also been included to convert the estimate to $2016/17. For the OPEX PFP model, we have extrapolated the estimated $263 million (in 2016) using the growth rate in the price index and the output rate of change using the PFP models output weights.

Using the 2016/17 outputs from the Western Power AA4 operating expenditure and indirect cost model yields the following OPEX estimate for Western Power in 2016/17.

Table 19 Predicted 2016/17 OPEX from AER modelling

OPEX model	2015/16 OPEX	Output growth	OPEX price growth	Predicted OPEX in 2016/17
OPEX PFP	$262.8 M	-0.3%	1.96%	$267.0 M
SFA model	$283.0 M	-0.63%	1.96%	$286.6 M
Cobb Douglas model	$271.2 M	-0.55%	1.96%	$274.8 M
Translog model	$276.4 M	-0.45%	1.96%	$280.4 M

7.3.2 Transmission

Using the AER's transmission benchmarking model[36] and extrapolating forward to 2016/17 Western Power's (transmission) predicted OPEX in 2016/17 is $109.5 million. This model uses the same output specification as used to benchmark the distribution networks although different weights are used to aggregate them into a single output index (refer Table 11 and Table 12).

The outputs used are customer connections, circuit length, ratcheted peak demand and energy throughput, with energy not supplied excluded from our analysis.

The AER has been reluctant to infer efficiency differences from results of their OPEX benchmarking because of the small number of transmission networks and uncertainty around the transmission output specification. Whilst in the first Annual Benchmarking Report (2014) the AER used voltage weighted connections, circuit length, energy throughput and ratcheted peak demand as outputs more recently this specification has changed with customer connections replacing voltage weighted connections. This change in model specification has had a significant impact on the benchmarking results with the smaller networks ElectraNet and TasNetworks performing worse than under the previous benchmarking model. The steps taken to arrive at Western Power's transmission OPEX estimate are outlined below.

Step 1 - Reconstruct the AER's transmission model (without energy not supplied) including Western Power transmission data

Step 2 - Use ElectraNet as a comparison point to create a productivity score in 2016

Step 3 - Extrapolate predicted OPEX in 2015/16 forward to 2016/17

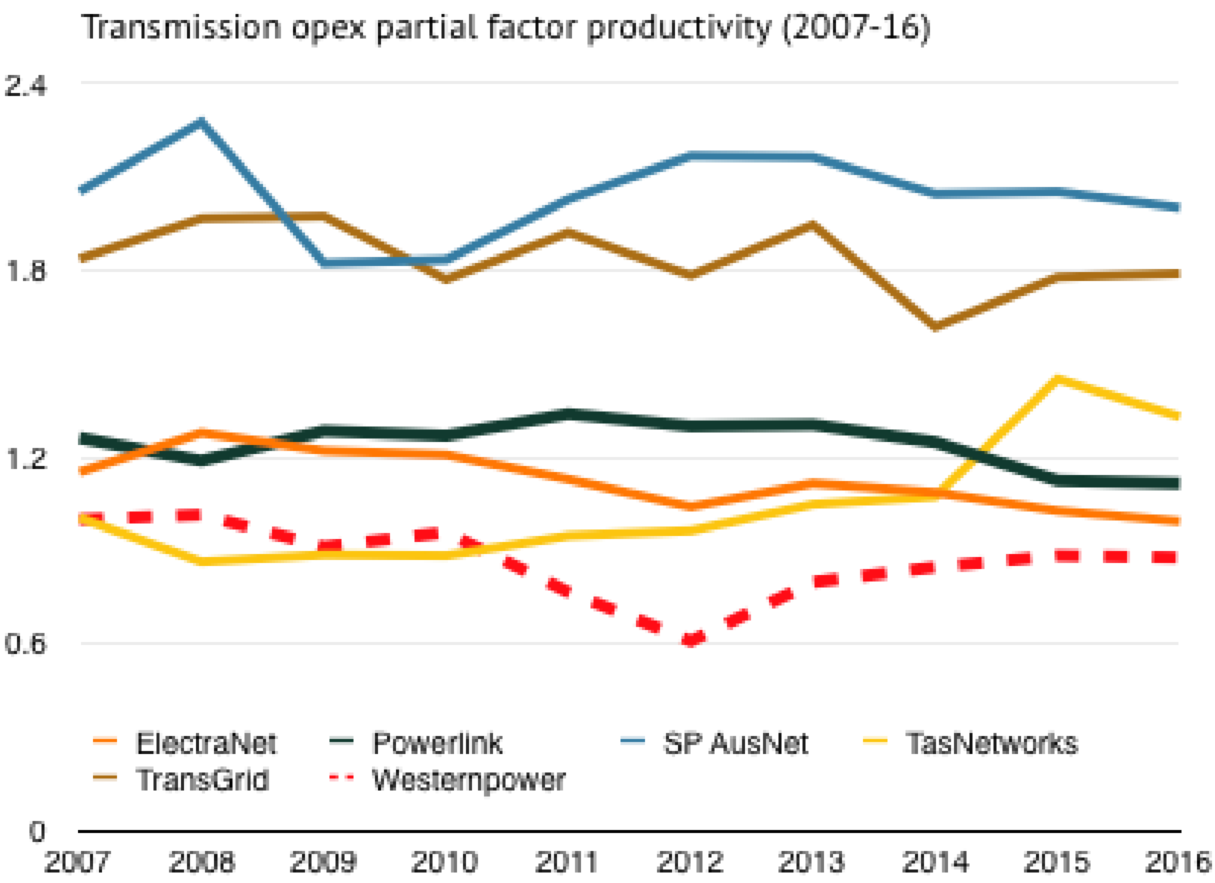
Step 1 - The AER's transmission OPEX model

Using the current model specification Western Power (transmission) rank 6th out of 6 in the OPEX productivity measure. The output specification includes the following outputs with weights in brackets; energy throughput (23%), ratcheted peak demand (19%), customer numbers (20%) and circuit length (38%). Energy Not Supplied is excluded from the output specification as we were unable to access Western Power's historic information for this variable. The reason an OPEX partial factor productivity model is relied upon for the transmission benchmarking is because, with five transmission networks within the NEM, there is insufficient information to construct a robust transmission cost function.

The results from the OPEX partial factor productivity model are included below. In 2016 Western Power was the 6th ranked network among those benchmarked.

[36] AER, *Position Paper: AER Review of Economic Benchmarking of Transmission Network Service Providers*, 9 August 2017

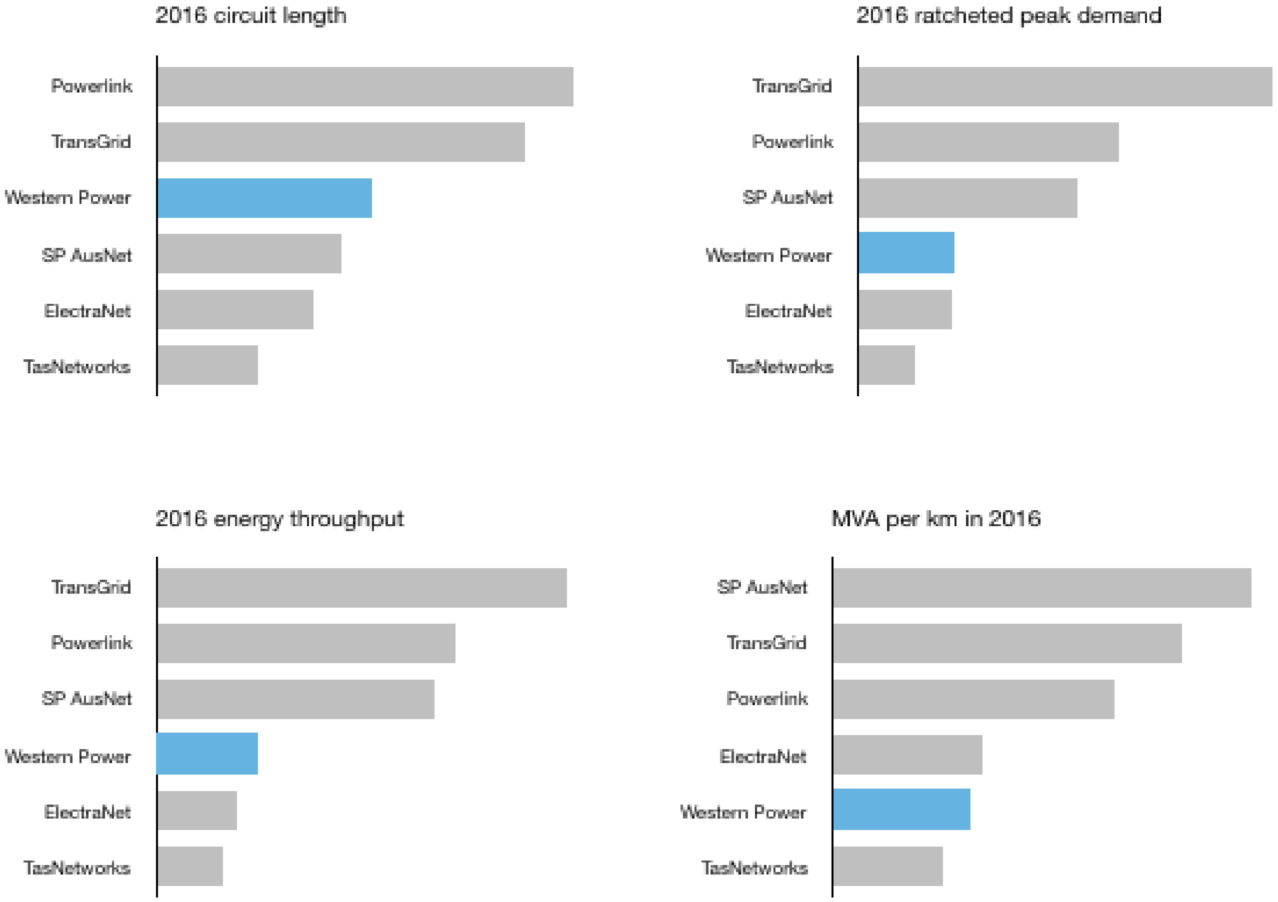
Figure 25 Transmission OPEX Partial Factor Productivity



Step 2 - Choose a comparison point

As with the distribution benchmarking, the next step in producing an OPEX estimate is deciding to which transmission network Western Power should be compared. Whilst AusNet Services is the closest comparator in terms of circuit length, ElectraNet is the closest with respect to peak demand, energy throughput and average MVA rating of the transmission lines. ElectraNet and TasNetworks are also the only transmission networks that connect to a single distribution network and serve a single large city. Based on these measures, we consider ElectraNet provides the best comparator from which to gauge the productivity outcomes of Western Power's transmission network over the benchmarking period. In addition, the use of ElectraNet as the comparator for Western Power (transmission) will enable a state based comparison for Western Power's network relative to an SA Power Networks/ElectraNet aggregated network.

Figure 26 **Comparison of transmission network characteristics**



Using the OPEX benchmarking results presented in step 1, Western Power's OPEX productivity in 2016 relative to ElectraNet, the chosen comparison point, was 88.4%.

Step 3 - Predicted OPEX in 2016/17

Taking the OPEX productivity figure of 88.4% and applying it to Western Power's actual transmission OPEX in 2015/16 ($120.6 million) provides an estimated OPEX of $106.6 million in 2015/16.

The next step is to incorporate output growth and real OPEX price growth between 2015/16 and 2016/17 to provide an OPEX estimate in 2016/17.

We have used the following figures in 2016/17 to measure output growth:

- energy throughput (GWh): 17,764
- ratcheted peak demand (MVA): 3,878
- customer connections: 1,113,316
- circuit length (km): 7,781

These values provide an aggregated output growth of 0.8% which, when combined with the 1.96% real price escalation, increases the OPEX estimate to $109.5 million in 2016/17.

Table 20 Transmission OPEX estimate for 2016/17

OPEX model	2015/16 OPEX	Output growth	OPEX price growth	Predicted OPEX in 2016/17
OPEX PFP	$106.6 M	0.82%	1.96%	$109.5 M

7.3.3 Combined electricity network

The predicted OPEX for the Western Power combined network in 2016/17 is in the range $368 million to $379 million.

Western Power's benchmarking submission noted the differences in the classification of transmission and distribution assets between the WA Access Code (which classifies electricity assets 66 kV or higher as transmission) and the NEM networks[37]. If there are differences in the way Western Power is allocating operating expenditure to distribution or transmission with its comparators then this will impact on the respective distribution and transmission benchmarks. For example, if Western Power allocates OPEX for all assets at or above 66 kV to its transmission network then this will make the distribution part of its network appear to have higher productivity in benchmarks at the expense of its transmission network relative to comparator networks that have 66 kV assets[38]. In addition, in order to facilitate benchmarking against NEM peers Western Power has had to reallocate and recut much of its data in order to satisfy the definitions used by the AER when collecting physical and financial data for use in benchmarking.

To mitigate the impact of boundary and data interpretation differences we have provided benchmarks below that aggregate network outputs and inputs at a state level.

The benefit of using the current AER output specification for transmission networks is that transmission and distribution outputs can be combined at a state level to provide a comparison between Western Power and SA Power Networks / ElectraNet. As the output weights used in in the distribution and transmission index models are different there are two sets of results obtained. The productivity results along with estimated OPEX are displayed below.

[37] For example some NEM distribution networks operate at voltages at and above 110 kV

[38] In this benchmarking exercise we have attempted to adjust for this specific difference between SA Power Networks and Western Power by incorporating an OEF for network design

Figure 27 State-based OPEX productivity - transmission weightings

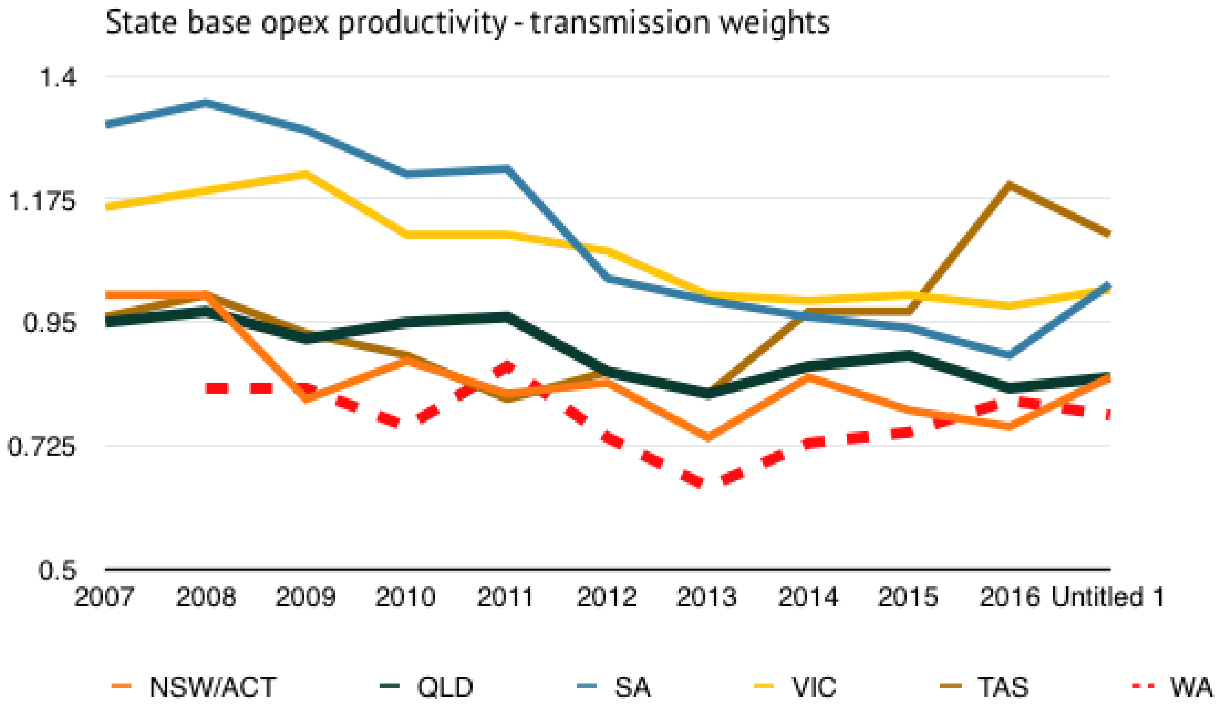
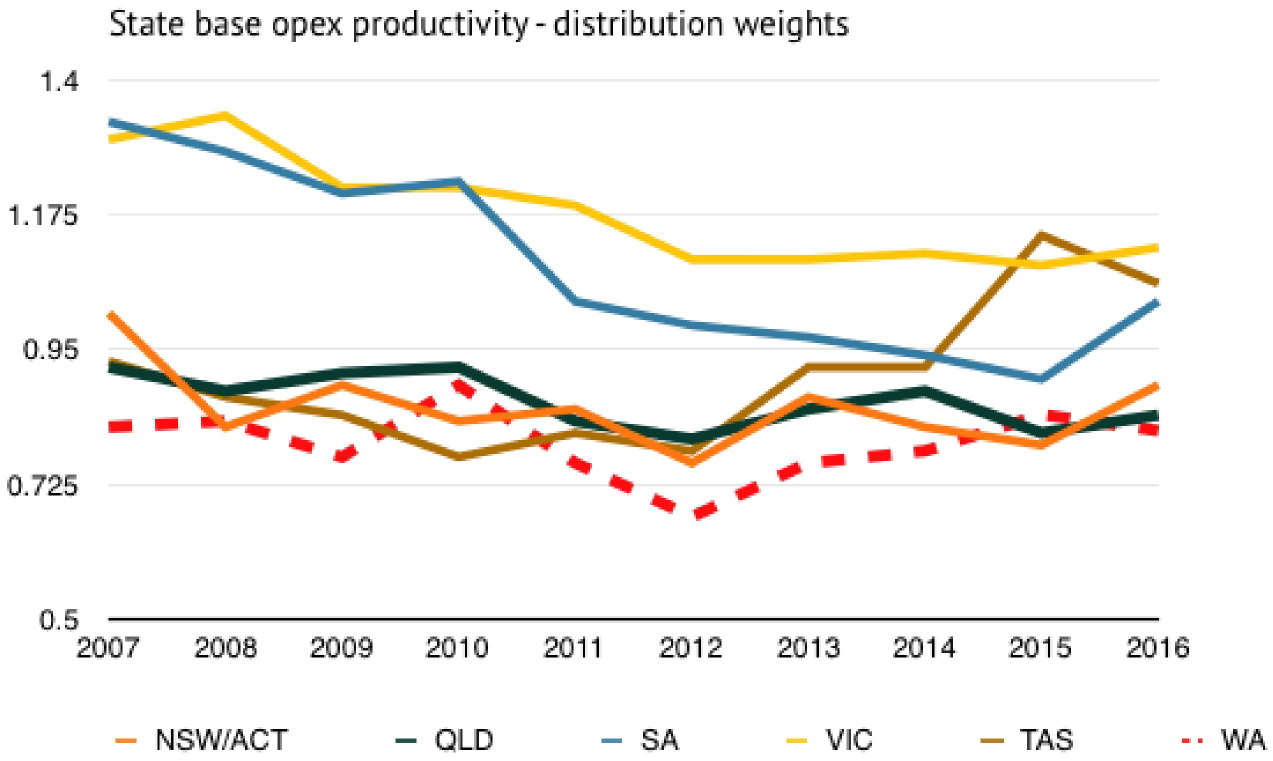


Figure 28 State-based OPEX productivity - distribution weightings



The aggregated model ranks Western Power 6th in 2016 using both sets of output weights - although the Western Power OPEX productivity is comparable to Queensland utilities using the distribution output weights that place a higher weighting on customer connections. It is important to note that whilst OEF's have been applied to SA Power Networks / ElectraNet's OPEX, adjustments haven't been made for the other four States. This means that in terms of comparisons on a like-for-like basis, South Australia should be used as Western Power's comparison point. We note that whilst adjustments have been made to the Western Power data for comparison with SA Power / ElectraNet, there are likely to be some OEF's that would be expected to work in the opposite direction. For example, a combined SA Power / ElectraNet network would likely see reduced corporate overheads in areas such as Finance, Human Resources and the Office of the CEO if merged into a single entity - as an example TasNetworks has reduced corporate overhead costs by around 20% since 2012 with the merging of transmission and distribution functions.

Therefore, using the combined OPEX PFP model and using SA Power Networks / ElectraNet as the comparison point, the predicted OPEX in 2016/17 is between $368 million and $379 million.

Table 21 Predicted total network OPEX for 2016/17

OPEX model	2015/16 OPEX	Output growth	OPEX price growth	Predicted OPEX in 2016/17
Transmission weights	$363.1 M	0.24%	1.96%	$367.5 M
Distribution weights	$360.2 M	-0.17%	1.96%	$378.6 M

8. NFIT compliance

The efficiency of forecast capital expenditure will be considered in detail in other sections of this report. This section establishes the principles that govern the requirements to support forecast capital expenditure and the basis upon which the ERA will determine the robustness of those forecasts.

All forecast capital expenditure is required to be likely to meet the requirements of the NFIT. It is not possible to be satisfied at the start of a regulatory period that all proposed expenditure will meet the requirements of the NFIT. However it is incumbent upon Western Power to provide sufficient evidence in support of the forecast expenditure to enable the ERA to reasonably expect that the requirements of the NFIT are likely to be satisfied.

In accordance with the requirements of the NFIT, demonstration of the efficiency of forecast expenditure must include:

1. Appropriate and robust energy, demand and customer number forecasts. These forecasts will be considered further in other sections of this report.
2. Appropriate network planning processes
    a. Western Power has moved to a risk based planning process for both the transmission and distribution networks. This journey from a more deterministic planning approach has been undertaken both internally and externally with stake holders that include Energy Safety, the ERA and the Public Utilities Office (PUO). Western Power confirmed that this change in process is strongly supported by these stakeholders.

    b. Western Power has provided reasonably strong evidence of their risk based planning approach and this is supported by the ERA. The technical rules under which Western Power operates have a strong focus on deterministic planning requirements but there is provision in the Code for Western Power to seek exemptions from the technical rules where they consider it prudent to plan on an alternative basis. The ERA has actively accommodated applications for exemptions from the technical rules based on sound risk based planning.

    c. The Code requires, Western Power to consider non-network options in its options analysis. All planning activities routinely consider such options and Western Power has processes in place to seek costs for such options. Further information and comment will be provided in other sections of this report.

3. Appropriate governance of capital expenditure proposals with respect to approval of expenditure
    a. This will be covered in other sections of this report.

4. Appropriate development of forecast costs
    a. Western Power has a dedicated group responsible for developing project costs and also who are responsible for the robustness of the various components of unit costs. The costs used for options analysis are termed A0 costs and are considered to be in the order of ±50% in accuracy. Non-network costs are determined through a combination of historic values and requests for interest from suppliers.

    b. Once a project is proposed the costs are determined at an A2 level of accuracy which is considered to be ±10%.

    c. For distribution projects Western Power utilises a system called distribution quotation management (DQM) which is an integrated design, quotation and project tracking tool. Costs are based on unit costs for standard building blocks (called compatible units) of which there are some 600 individual compatible units. DQM incorporates a contingency factor of 10% against all quotations primarily because customer funded work is carried out on the basis of an upfront quotation which is not adjusted for actual costs upon completion of the works. The compatible unit prices do not, in themselves, include any contingency cost and it is considered reasonable to include a general contingency in providing applicants with a firm quotation for the work. No profit margin as such is included in the quotation for works and Western Power does not double recover any of its costs for customer funded work. There are processes in place to regularly update the unit rates for changes to material, labour and contractor rates.

d. DQM is also used to determine the costs of internally driven work.

e. The contingency factor for works is not automatically included in the development of the forecast costs. However it is not clear whether the forecasts for internally driven distribution works have included a contingent component.

f. In general, and subject to verification that contingent costs are excluded, Western Power's approach to developing project costs and also maintaining unit costs for routine work appears reasonable.

5. Appropriate delivery costs

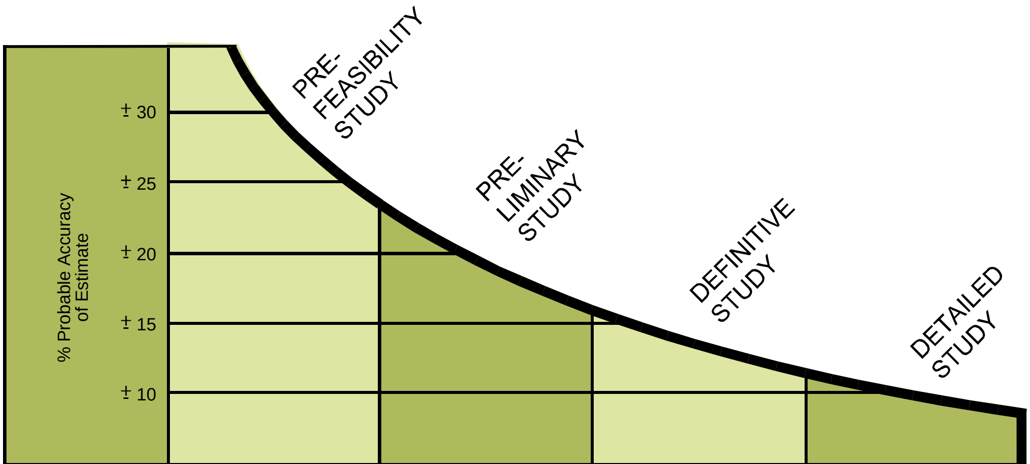
   a. Western Power has a defined process for delivery of works. Project delivery is undertaken through a combination of internal and external delivery. Contracts are issued individually for larger and bespoke projects. Most distribution work undertaken by contract is based on a schedule of rates and those rates are tested in the market place from time to time.

9. Assessing proposed CAPEX allowances

In establishing a criterion for assessing the reasonableness of the Western Power CAPEX allowances, we are of the opinion that consideration must be given to the level of accuracy that can be achieved.

The graph shown in Figure 29 indicates the levels of accuracy that can be expected for estimates prepared for capital works at various stages of a project development. Due to the different levels of engineering input, and completeness in the design, there are various levels of accuracy that can be reasonably expected in forecasts.

Figure 29 Standard estimate accuracy levels



Type of Estimate	Order of Magnitude	Preliminary	Definitive	Detailed
Provided Documentation	• Product capacity and Location • Cost Data on Similar Projects • Major Equipment List	• Preliminary Equipment List • Engineering Line Diagram • Plant Outline General Arrangement • Maps and Surveys • Bench Test Results • Nature of Facilities	• Equipment Specifications and Vendor Quotations • Construction Schedule • Electrical One Lines • Piping and Instrumentation Flow Diagrams • Soil Data and Architect Features • Site Survey and Labour Complete	• Bulk Material Specifications and Vendor Quotes • Construction Specification and Sub Contractor Quotations • Engineering Advanced Approximately 10%
Definition of Scope of Work	Conceptual	Approximate	Clearly Described Essentially Complete	Complete. Well Detailed
Estimating Procedure	Factoring	Combination of Factoring and Quantity Take-Off	Most Quantity Take-Off. Very little Factoring	Complete Quantity Take-Off
Use of Study	Comparison/ Rejection	Final Feasibility	Budget	Funding

The level of information made available to us by Western Power for assessing the selected CAPEX projects and programs was typical of pre-feasibility study level, which suggested an accuracy of ±30%. The comparative estimates we have generated are Class 4 estimates as classified in the AACE International *Recommended Practice No. 17R-97 Cost Estimating Classification System*.

These estimates are based on 1% to 15% project definition and has an expected accuracy range of ±30%. Class 4 estimates are used for feasibility and concept studies.

***Table 22 AACE IRP No. 17R-97 generic cost estimate classification matrix*[39]**

Estimate Class	***Primary Characteristic***	***Secondary Characteristic***			
	Level of Project Definition Expressed as % of complete definition	**End Usage** Typical purpose of estimate	**Methodology** Typical estimating method	**Expected Accuracy Range** Typical +/- range relative to best index of 1 (a)	**Preparation Effort** Typical degree of effort relative to least cost index of 1 (b)
Class 5	0% to 2%	Screening or Feasibility	Stochastic or judgement	4 to 20	1
Class 4	1% to 15%	Concept Study or Feasibility	Primarily stochastic	3 to 12	2 to 4
Class 3	10% to 40%	Budget, Authorisation or Control	Mixed, but primarily stochastic	2 to 6	3 to 10
Class 2	30% to 70%	Control or Bid/Tender	Primarily deterministic	1 to 3	5 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Deterministic	1	10 to 100

(a) If the range index value of 1 represents +10/-5%, then an index value of 10 represents +100/-50%

(b) If the cost index of 1 represents 0.005% of project costs, then an index value of 100 represents 0.5%

Based on these estimate classifications and considering Western Power has relied upon historic project data, we have adopted a nominal criterion of ±15% as the first pass for comparing the Western Power estimates with our reference comparative estimates as a test for reasonableness. Where there was variance between the Western Power CAPEX forecast allowance for a project or program and our comparative estimate of less than ±15%, we considered the Western Power allowance as reasonable and no further detailed assessment was undertaken.

For those Western Power estimates where the variation is outside our nominal range, we have reviewed any known project specific issues to identify the potential reasons.

[39] AACE International, *Recommended Practice No. 17R-97: Cost Estimating Classification System (TCM Framework: 7.3 – Cost Estimating and Budgeting)*, 12 August 1997, p. 2

10. Forecast CAPEX - distribution

10.1 Western Power AA4 proposal

Western Power has forecast distribution CAPEX of $2,877.3 million, in real FY2016/17 terms, which represents 65% of total CAPEX for AA4. Table 41 shows a comparison of AA3 and forecast AA4 distribution CAPEX.

Table 23 Comparison of AA3 and AA4 distribution CAPEX ($M at 30 June 2017)[40][41]

Regulatory category	AA3 approved	AA3 actual	AA4 forecast
Growth[42]	1,866.3	1,484.2	1,207.2
Asset replacement/renewal	1,627.8	1,675.1	1,375.6
Improvement in service	35.7	24.6	113.3
Compliance	567.9	460.5	181.3
Total	**4,097.7**	**3,644.4**	**2,877.3**

Table 24 shows the forecast distribution CAPEX in AA4 by regulatory category in real FY2016/17 dollars.

Table 24 Forecast distribution CAPEX for AA4 ($M at 30 June 2017)[43]

Regulatory category	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Growth[44]	244.8	252.6	232.5	235.5	241.8	1,207.2
Asset replacement/renewal	303.9	286.7	269.9	251.5	263.5	1,375.6
Improvement in service	27.8	34.7	18.9	16.8	15.0	113.3
Compliance	27.7	43.2	41.7	34.2	34.4	181.3
Total	**604.3**	**617.2**	**563.1**	**538.0**	**554.8**	**2,877.3**

For AA3, Western Power underspent their approved capital expenditure allocation of $4.10 billion by approximately 11%, and for AA4, Western Power is proposing a further decrease on AA3 actual expenditure of approximately 21%, due to decreases in asset replacement and renewals, compliance and growth offsetting an increase in improvement in service expenditure due to replacing SCADA & Communications equipment.

[40] Includes real cost escalation and indirect costs

[41] Western Power Excel model *10.4 - AA4 Regulatory Revenue Model.xlsx*, worksheet *Dx_Inputs* rows 111 to 156

[42] Includes gifted assets

[43] Western Power Excel model *10.4 - AA4 Regulatory Revenue Model.xlsx*, worksheet *Dx_Inputs* rows 111 to 156

[44] Includes gifted assets

Table 25 shows the total proposed forecast distribution CAPEX (direct costs only) in AA4 by regulatory category in real FY2016/17 dollars.

Table 25 Forecast distribution CAPEX for AA4 ($M direct costs at 30 June 2017)[45]

Regulatory category	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Growth[46]	216.0	223.8	208.1	206.4	210.5	1,064.6
Asset replacement/renewal	251.2	239.5	228.0	206.1	214.7	1,139.4
Improvement in service	23.0	29.0	16.0	13.8	12.2	94.0
Compliance	22.9	36.1	35.3	28.0	28.1	150.3
Total	**513.0**	**528.2**	**487.3**	**454.2**	**465.5**	**2,448.3**

10.2 Asset replacement

10.2.1 Pole management

Following on from the completion of the pole rectification work required under the EnergySafety order during AA3, Western Power has reverted to pole management in line with the risk strategies as defined in the NMP[47] for AA4.

The NMP stated that as at 30 June 2016, there are 253,537 poles in a defective condition, with 136,280 to be replaced and 117,257 requiring reinforcement. 16% of these poles are regarded as high risk, being located in extreme or high-risk FRZs or high public safety zones. In AA4, Western Power has prioritised 125,000 poles to be rectified, of which 61,000 poles will be replaced and 64,000 will be reinforced. The total proposed forecast for AA4 is $525 million (direct costs only).

Western Power suggested that the level of capital expenditure and the activities identified for pole management provides for a level of certainty to reducing the risk of pole management related incidents to an acceptable level. Western Power noted that for the Distribution Replacements Investment [redacted]

10.2.1.1 Volumes

The key challenges in managing the wood pole population are:

- deterioration due to ageing
- varying degrees of condition deterioration, with associated varying likelihood of failure and presenting varying levels of risk due to location

[45] Western Power Excel model *10.4 - AA4 Regulatory Revenue Model.xlsx*, worksheet *Dx_Inputs* rows 111 to 156

[46] Includes gifted assets

[47] Western Power, *Network Management Plan: Transmission and Distribution Network 2017/18 - 2027/28*, August 2017, section 5.5.1, Table 131, p. 140

[48] Western Power, *Network Management Plan: Transmission and Distribution Network 2017/18 - 2027/28*, August 2017, p. 246

- risk of fire or injury due to pole failure

The primary strategy used by Western Power in identifying poles for replacement or reinforcement is based on condition assessment and prioritised by risk. The proposed investment for AA4 relates to addressing the defects associated with 125,000 poles and this is projected to maintain the level of unassisted asset failures per annum for wood poles at a similar level to that as at 30 June 2016 (approximately 305 wood poles), and increase the number of poles in-service beyond their MRL from 7% to 20%.

We accept that based on the feedback from the customer engagement program that commenced in 2015, Western Power is targeting expenditure in AA4 to addressing particular reliability hotspots rather than broader network performance and reliability issues. We note that one of the survey themes was Network Safety that proposed two key drivers[49] for Western Power's business plans in this area:

- proposed five-year inspection cycles
- implementation of consequence approach to fire prevention

The planned action in response to these drivers is to *"… forecast expenditure on pole management … to maintain the current level safety risk associated with these assets …* [by adopting] *… more efficient asset management practices …* [resulting in] *… lower replacement volumes and investment in … wood pole management … around 40 per cent lower than during the AA3 period whilst maintaining network safety risk."*[50]

We accept the condition assed risk-based approach will lead to more efficient expenditure, although we disagree with comparing expenditure directly with AA3 as Western Power was responding to an EnergySafety work instruction during this period, and not relying upon maintaining a risk profile for the wood population.

For assessing risk, the percentage in-service beyond the MRL (that is, the average age at which an asset type has been historically replaced) is considered a leading measure, and represents a high-level assessment of ongoing performance of an asset, and means that a higher value characterises a higher risk of unassisted failure without implying that an asset is likely to fail in the short-term. Unassisted failure rates is based on the historic failure rate.

We note that the risk profile associated with transmission support structures is an overall medium network risk (no High rankings, 3 Medium rankings)[51] which is relatively lower than the overall high network risk for distribution support structures (3 High rankings, 2 Medium rankings) whilst the proposed replacement CAPEX for transmission support structures is projected to reduce the percentage of wood pole assets in-service beyond the MRL to 0% (refer section 11.3.2), whilst the percentage of wood poles in-service beyond the MRL grows from 7% to 15% by the end of AA4, and projected to increase further to 20% by the end of AA5.

Although there is a projected increase in the over-age percentage of distribution wood pole population, unassisted asset failures for wood poles are forecast to remain relatively consistent with AA3 performance (305 in AA3 and 256-310 for AA4).

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[49] Western Power, *Access arrangement information*, 2 October 2017, Table 4.8, pp. 41-2

[50] Ibid., Table 4.9, p. 44

[51] The rankings are Extreme, High, Medium, Low or No material risk. Rankings apply to different risk types - fire, electric shock, physical impact, environment, power quality and reliability, together with an overall rating which is derived from the risk type with the highest risk ranking.

We consider the proposed distribution pole replacement volumes to be consistent with the Western Power corporate goal of reducing expenditure during AA4 whilst maintaining the current network safety risk, by allowing the average pole population age to rise, together with potentially the risk profile. On this basis, we accept the proposed AA4 pole replacement/reinforcement volumes, but not the principle as outlined in the Distribution Replacements Investment Risk that *"… as the total quantity of assets currently tagged for replacement (due to assessed condition or attributes) exceeds the proposed total replacement volume, a proportion of currently tagged assets will not be addressed by the end of the plan period."*[52] (refer section 10.2.1)

Whilst Western Power suggests that the investment is linked to the quality of condition data, and targets assets with historically high likelihood of failure, we would expect that Western Power will not allow safety or the risk profile of the current wood pole population to be compromised should condition assessment recommend replacement or reinforcement in volumes and costs beyond those forecast, particularly given that the current replacement/reinforcement volumes project a potentially higher risk profile by the end of AA5.

10.2.1.2 Costs

We have developed comparative standard job estimates for wood pole replacement and reinforcement based on our standard job descriptions as shown in Table 26.

Table 26 Wood pole replacement/reinforcement standard job descriptions

Description	Assumptions
Replacement • Replacement based on like-for-like replacement including all fixtures and fittings • Procurement and installation of new wood pole • Drilled and backfilled with excavated earth • Assumed normal/average construction difficulties • Nominal traffic control allowance of 2 men for 8 hours • Includes all fixture and fittings • Excludes costs associated with outages and/or switching • Excludes consideration of costs associated with conductor or pole top devices • Excludes any disposal costs for redundant pole	**Material** • 11 m 6 kN CCA pole delivered to site • Disposal of old wood pole • Hole for pole is drilled and backfilled with excavated earth **Work crew** • 3 man pole standing team • 2 man pole earthing • 2 man pole fit-out • Field supervision • 1 man plant operator **Equipment** • One lifter borer (with pole jinker) • One general duty 14 m extended work platform • One knuckle boom crane truck **Contingency** • Included 15% contingency allowance
Reinforcement • Assumed normal/average construction difficulties • No traffic control allowance	**Material** • Stake for pole **Work crew** • 2 man crew **Contingency** • Included 15% contingency allowance

[52] Western Power, *Network Management Plan: Transmission and Distribution Network 2017/18 - 2027/28*, August 2017, p. 246

Based on these standard descriptions and assumptions, our comparative estimates are:

- Pole replacement - **$8,074**
- Pole reinforcement **- $1,035**

Using the volumes nominated by Western Power for AA4, our comparative estimate for costs are:

61,000 * $8,074 + 64,000 * $1,035 = **$558.75 million**

Our estimate is comparable to the Western Power forecast, with the variance to the proposed AA4 allowance of $524.98 million being approximately 6%, which is within our nominal ±15% test for reasonableness.

We recommend the Western Power forecast of $525 M (direct costs only) for pole management is accepted, based on the Western Power proposed replacement/reinforcement volumes, which we assumed to be appropriate for maintaining the current risk profile during AA4.

10.2.1.3 Performance measurement

In their annual report, Western Power publishes two measures in relation to its wood pole program:

- number of wood poles reinforced
- number of wood poles replaced

Annual actual performance is compared to the target. We consider that these two indicators reflect activity within the wood pole program rather than reporting the effectiveness of the wood pole initiatives Western Power has in place.

During AA3, Western Power was subject to the Energy*Safety* Wood Pole Order 01-2009 which required the replacement or reinforcement of approximately 170,000 rural poles and 290,000 poles in total. This order was put in place to drive improvements in:

- pole inspection
- pole strength assessment
- serviceability criteria
- wood pole management
- rural wood pole technical engineering
- rural wood pole safety improvement

As a result, we consider the performance measures reported in the annual reports were relevant to the progress Western Power was making against this wood pole order. We note that some electricity distribution utilities within the NEM report the performance of their wood populations in different ways, including the following examples:

- rural/urban poles condemned
- rural/urban poles replaced
- HV/LV poles condemned
- HV/LV poles replaced
- condemned vs non-condemned poles replaced
- reinforced vs non-reinforced poles replaced
- pole replacement rate as % of total population
- pole functional failures per 100,000 poles
- pole replacement expenditure per installed number of poles
- % of currently installed poles in-service for 50 years or more

We are of the opinion that measuring the performance of the wood pole management program should be related to output rather than input such as the number of poles treated. The performance indicators should focus on quality (risk) and time. Another option would include cost, such as $ per pole replaced or $ per pole reinforced.

Therefore, we recommend that Western Power consider reporting on:

- unassisted wood pole failure rate as a % of wood pole population → quality/outcome measure
- % of current pole population over-age (in-service beyond nominal asset life) → risk exposure measure
- planned vs actual for condemned poles and planned vs actual for reinforced poles → measure of asset strategy implementation
- pole replacement rate as % of total population → useful for comparison with other electricity distribution utilities

We believe these measures will indicate the effectiveness of the inspection program, and the overall performance of the wood pole population.

10.2.2 Conductor management

10.2.2.1 Business Case

This proposed investment is estimated at $219 million (excluding indirect costs and excluding real cost escalation). This is made-up of replacing 2,196 km of distribution overhead conductor in AA4 period, which is approximately 3% of Western Power's total distribution overhead conductor portfolio population. We reviewed the business case for the Distribution Overhead Corridor, which also contains Conductor Management program for financial year 2017/18. We understand that a similar business case containing the Conductor Management program for the financial year 2018/19 is presently in the early stage of development.

An asset overview of the distribution overhead conductor population at increased likelihood of failure and the prioritisation criteria for targeted response are contained within the Western Power's NMP 2018/18 to 2027/28 (section 5.5.2 and section 8.1.2.4 in Table 255).

Western Power has justified this proposed amount with an objective of maximising network risk reduction per dollar of expenditure by delivering this replacement expenditure (REPEX) within the targeted zones, where distribution overhead conductor is replaced coincidentally with or in close proximity to other distribution overhead assets such as wood poles or pole-top plant, or in discrete (targeted asset) segments across the network.

The proposed REPEX is based on volumetric estimate, i.e. volume of types of distribution overhead conductor proposed for replacement times the estimated unit cost of the corresponding asset types. The unit cost are estimated for each distribution overhead conductor construction type (i.e. single phase high voltage (HV), three phase HV, etc.) and general location (urban, rural, metro) using Western Power's historical project experiences. The year-on-year variation during the AA4 period in unit rates reflects the particular mix of conductor segments selected on a risk reduction per dollar basis.

10.2.2.2 Assessment

In order to assess the reasonableness of the proposed volume or quantity of the distribution overhead conductor, we reviewed the following information:

- Prioritisation strategy for targeted replacement of this asset in the NMP 2018/18 to 2027/28 document. This document also provide information of conductor sampling program, metallurgical test, defect types and asset failure history to support the proposed REPEX program.
- The age profile of this asset class and noted that Western Power has a material volume of old assets which is a good proxy for deteriorating asset condition. The MRL of Western Power's distribution overhead conductor is 70 years (with nearly ±13 years of standard deviation) based on its recent asset replacement history.
- The distribution overhead conductor replacement volume data reported in the RINs in the recent past by the peer businesses in the NEM. This comparison suggests that the proposed 3% replacement in a given 5 years' regulatory period from the total asset population and with similar asset age profile is generally consistent.

On this basis, we are satisfied with Western Power's proposal to replace 2,196 km of distribution overhead conductor in AA4.

Western Power's proposed weighted average unit cost estimate for this REPEX program is approximately $100,000 per km. In order to assess the reasonableness of this cost, we reviewed the following information:

- The business case for the Distribution Overhead Corridor containing the Conductor Management program for financial year 2017/18. This document prioritise and propose to replace 321 km of the selected conductor (from the 2,196 km in AA4) with the weighted average unit cost of approximately $96,000 per km.
- Independent cost estimate information researched by GHD indicates the unit cost of the distribution overhead conductor to range from $20,000 (single phase in rural route) to $120,000 (for three phase in metro route) per km. GHD referred to the unit cost data reported in the RINs in recent years by the peer businesses in the NEM. GHD also sourced this information internally from its power network engineers and project managers with recent re-conductoring experience for Australian DNSPs.

We note that a significant portion of older (and with poorer condition) overhead distribution conductor are of low voltage (LV) and single phase SWER types. Western Power is prioritising and proposing to replace most of such conductors in AA4 period. It is noted that these types would be estimated at the lower end of the $20,000 to $120,000 per km range and should bring down the weighted average unit cost of the proposed REPEX program.

From our analysis, we are of the view that the weighted average unit cost for Western Power distribution overhead conductor replacement program should be $96,000 per km rather than Western Power's proposed $100,000 per km estimate.

10.2.2.3 Conclusion

We recommend a reduction of the weighted average unit cost to $96,000 per km. We consider that this cost aligns to the committed business case for financial year 2017/18 which has been developed with more definitive information. Accordingly, we recommend the forecast REPEX for distribution overhead conductor (labelled as conductor management in the literature provided by Western Power) should be reduced to $210 million (excluding indirect cost and excluding real cost escalation).

10.2.3 Advanced Metering

Advanced metering is associated with a large quantity of capital expenditure, as well as attracting significant attention for the potential benefits it can provide. We have decided to analyse this business case to understand if Western Power has reliably quantified the costs and benefits of the program and to determine the quantity of costs that would be appropriate for recovery.

We have taken time to comprehend the business case, and analysed the volume of meters to be installed to determine if this is appropriate. Costs and benefits associated with this process have been analysed through a benchmarking process to inform us of the financial benefits that Western Power can deliver to their customers. We have drawn conclusions based on these analyses and present them at the end of this section.

We have reviewed the following Western Power documents in relation to the expenditure requirements for Metering, and in particular AMI:

- Access Arrangement Information AA4
- Attachment 8.1 Forecast Capital Expenditure Report
- Attachment 8.2 Advanced Metering Business Case
- Attachment 8.2.1 Metering Strategy
- GHD001 AA4 Investment portfolio - 18 Oct 2017
- GHD014 - Advanced Metering Regulated Cost Benefit Analysis (CBA) Model

10.2.3.1 BAU Meter Volumes

The Advanced Metering Business Case identifies the Business as Usual (BAU) number of new and replacement meters of 198,000 over 3 years (which is consistent with the forecast of 355,493 over the 5-year period for AA4).[53] The volume of meters expected to be new or replacement was based on the volumes changed over the AA3 period. However, there was a one-off 54,000 meters changed in AA3 that were considered not to meet the required accuracy standard and this volume should be deleted from the forecasts for AA4. These 54,000 meters would also explain the increase in volume over the period 2014-15 to 2016-2017 compared with 2012-13 and 2013-14.[54] The 5-year BAU volume hence should be around 300,000 or 60,000 p.a.

The Advanced Metering business case states that there are no meters in the existing fleet that do not meet the current accuracy requirement hence the reason for suggesting replacement of 104,120 meters due to end of life/type compliance issues is questioned.[55] The metering fleet age profile[56] indicates the total meters installed prior to 1980 is only 91,340 and hence replacing 104,120 meters would result in replacing the oldest meters about 40 years of age by the end of the AA4 period. If we assume the 54,000 quantity discussed above were incorrectly included in this quantity, then the quantity should be 50,120 meters and that would result in nominally no meters older than 50 years on the network by the end of the AA4 period. We believe that this supports our contention that the BAU volume should be reduced by 54,000 meters.

[53] Western Power, *8.2.1 Metering Strategy*, 2 October 2017, section 7.1, tables 5 & 6 pp. 28-9. Total of 355,493 represents the aggregate total forecast volumes for new connections and meter replacement.

[54] Ibid., section 4.1, table 4, p. 19

[55] Ibid., section 7.1, table 6, p. 29. Value is the total for Planned maintenance during AA4.

[56] Ibid., section 4.1, table 3, p. 19

There are approximately 125,510 new meters projected to be installed during the AA4 period.[57] Western Power forecasts the number of new customers[58] will be approximately 96,000 over the AA4 period; hence the total new meters for growth should be reduced by 28,510.

We are of the opinion that the BAU volume for new and replacements meters should be reduced to 273,493 based on:

- compliance-driven replacements should have been completed and hence 54,000 meters should be removed from the volumes in the AA4 period and from the Advanced Metering Business Case for BAU
- volume of new meters for growth should be reduced by 28,510 to align with the forecast number of new customers connected over the period

Therefore, our recommendation is for a 23% total reduction in meter volumes.

The impact to the business case of a reduced volume of BAU meter volumes is either a delay in benefits due to a lower number of smart meters installed or otherwise additional costs equal to the loss of life of replaced meters if the current volumes are retained.

Based on the current volumes being retained, the increased costs are calculated approximately by the PV of 23% of meters replaced each year with 10 years of life remaining. $1.14 million of remaining life of meters is estimated to be lost each year which would equate to around a PV of $12 million over 15 years.

10.2.3.2 Business Case

Western Power is proposing to increase the prevalence of AMI across the network during the AA4 period.

Western Power's strategic direction for metering is for the incremental deployment of advanced meters on a new and replacement basis over the next 15 years. Investment in advanced metering will preserve the Western Australian electricity market's ability to adapt to future changes in regulatory frameworks, in particular the possible future introduction of competition in metering. The Western Power Metering Strategy is focused on the first 5 years of this strategy implementation.

Western Power is not proposing a widespread roll-out of advanced meters considering it more prudent to introduce AMI as part of the standard meter replacement program. During the AA4 period the proposal is to 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.

Western Power has stated that, 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 [redacted] Therefore Western Power proposes to make distribution metering subject to the Investment Adjustment Mechanism (IAM) to accommodate for any large scale additional uptake of advanced metering.

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

[57] Ibid., section 7.1, table 5, p. 28. Value is aggregate of annual new connection forecasts.

[58] Western Power, *7.3 Peak Demand, Growth and Demand Forecasts*, 2 October 2017, section 3, p. 11

EnergySafety Order), the IAM would mean customers would be compensated in AA5 for the portion of the program not delivered.

Insights to customer views indicate that customers believe Western Power should use emerging technologies to deliver improved customer outcomes. Western Power's change to advanced meters will also enable time of use tariffs 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.

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. The use of advanced meters will be a significant enabling technology for a range of Demand Management /Non-network initiatives in the future.

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 NEM, 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 capital cost of the meters has been included in Western Power's Regulated Asset Base (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. Western Power states that the cost of advanced meters has fallen significantly in recent years and are now closer to the costs associated with installing and operating basic meters.

Western Power is subject to the Western Australian Metering Code and our understanding is that there is no intention to align this Code with the National Electricity Rules (NER). However it is useful to include the following information on proposed changes to the NER recognising that they may impact changes to the local Code in the future. The AEMC Rule change has been included in the latest version of the NER version 101 in Chapter 7. Clauses 7.2.5(d)(4) and 7.3.1(a)(4) specify the requirements for metering installations, and detail the need for a compliant meter to:

- display cumulative energy for an installation
- have an accuracy sufficient for the type of installation
- have electronic data transfer facilities to a metering data services database for types 1, 2, 3 and 4
- include a communications interface
- be capable of reading in either direction
- have facilities to record interval data
- be capable of recording active energy and, in some instances, reactive energy

In short, it "*… specifies the minimum services that a new or replacement meter installed at a small customer's premises must be capable of providing*" as stated in the AEMC information note relating to the Rule change.

The AEMC says that the new Rule is intended to drive competition in metering services, and "*... facilitate a market-led approach to the deployment of advanced meters where consumers drive the uptake of* *technology through their choice of products and services. This competitive framework for metering services is designed to promote innovation and investment in advanced meters that deliver services valued by consumers.*"

What the rule change does not do is specify that advanced metering must be installed with an associated IT/communications system. It only states what functionality/capabilities any new meter is required to have to be considered compliant.

We consider the practice of replacing old meters with modern electronic devices with enhanced capabilities in measuring energy consumption, monitoring power quality and identifying potential faults is appropriate. This is the way the electricity industry has moved, and would be consistent across all utilities.

However, we have concerns with Western Power's plan to immediately roll out the IT/communications to make use of the new capabilities of the advanced meters. We consider from the absence of substantial evidence of the magnitude of the costs and the benefits included in the business case, that there is a question about the business case demonstrating apositive net benefit to justify the expenditure of the IT/communications.

The Western Power proposal is based on providing 355,493 new and replacement meters over the next 5 years, at a total direct cost of $177 million which includes $137 million for the meters with AMI ready communication capability and $40 million for the ICT infrastructure.

The ICT infrastructure was identified in two separate capital activities and sub categories;

- Corporate - SCADA & Communications - $25.11 million[59, 60]
- IT Business Driven - IT - $15 million bundled in the total amount of $149.3 million[61, 62]

The business case for the program suggests a positive NPV will be achieved around 2026-27, based on quantified benefits for perceived metering service and network benefits such as remote access, interval and power factor data, pseudo-network protection functions in fault identification and power quality monitoring/management and identifying factors towards deferring network augmentation.

An initial assessment of the anticipated NPV of net benefits totalled $91.5 million over 15 years, which Western Power reduced to $54.9 million by an amount of $36.6 million following an internal review of the costs and benefits at on 24 October 2018[63].

The capital expenditure proposed in the AA4 period for the AMI is referenced in several documents, however there are inconsistencies in the values between documents, and with the forecast project costs included in a presentation by Western Power to ERA and GHD staff.[64] The Western Power presentation[65] identified the total investment in AMI to be $230 million, which covered all costs including $8 million for the ICT HUB and $40 million for indirect costs and contingencies.

[59] Western Power, *8.1 AA4 Forecast Capital Expenditure*, clause 518, p. 89

[60] Western Power Excel model *8.3 Western Power AA4 capital expenditure and capital contribution model*, direct cost only cell M39

[61] Western Power, *8.1 AA4 Forecast Capital Expenditure*, clause 664, p. 111

[62] Western Power Excel model *8.3 Western Power AA4 capital expenditure and capital contribution model*, direct cost only cell M45

[63] Western Power, AA4 Presentation Day 2

[64] Presentation received 24 October 2017 in Western Power Head Office, Wellington Street, Perth

[65] Western Power presentation, *AA4 proposal: Advanced Metering Infrastructure (AMI)*, 24 October 2017, slide 44

We found difficulty in assessing costs of the AMI program due to these inconsistencies in the data across the different documents reviewed. We recommend Western Power identifies all of the references to costs within the submission documents and clarifies the inclusions in the stated costs and corrects inconsistencies.

The business case recommended a three year program at a nominal cost of $144.5 million (including allowance for risk and escalation), which included a total of $90.6 million for incremental expenditure to move from the current basic meter standard to the advanced meter standard, as well as the associated communications infrastructure and IT system costs to facilitate remote acquisition of interval data and meter alarms.

We make the following comments with respect to the business case:

- The business case determined an NPV of $91.5 million over a 15 year rollout period which equated to an internal rate of return (IRR) of 17.5%. A 15 year period was chosen to equal the expected life of the meters and associated infrastructure, which is a valid approach. IT costs should have been included for replacement over this period.
- With a reduced NPV of $59.4 million, as indicated in the 24 October presentation to GHD, this would reduce the IRR to 11% based on the costs and benefits in the business case analysis. Western Power has quantified the benefits of utilising the enhanced capabilities of the new meters so as to suggest the cumulative benefits have a positive NPV within 8-9 years.
- The business case has not included sensitivity analysis to the input assumptions of costs and benefits which should have been carried out. GHD has questioned the viability of Option 3 in the business case as a result.

We consider that the business case should incorporate greater and more substantial evidence of the forecast costs and benefits.

10.2.3.3 Comparison with other AMI Programs

We reviewed costs and benefits on a per meter basis to create a benchmark to the Victorian experience and to AMI rollouts in the US and the UK. In order to compare the AMI programs, the BAU metering costs were added to the rollout costs and to the rollout benefits.

We reviewed the following studies to get insights into comparative benefits applied by other utilities:

- Cost Benefit Analysis prepared by Ameren Illinois
- Cost Benefit Analysis prepared by Deloitte for the Victorian Department of Treasury and Finance and the Futura and Oakley Greenwood reports, referenced within the Deloitte CBA
- Business Case prepared by BC hydro
- Business Plan prepared by Con Edison
- Cost Benefit Analysis prepared by the Department for Business, Energy & Industrial Strategy (UK)

While converting into Australian dollars could be done it would require judgement as to comparative technology and labour costs. What the benchmarking does is highlight our concern that the estimated costs in the business case are too low. If we assume that the revised reduction by Western Power in NPV is with respect to costs ($36.6 million) the total costs may still be too low

The results point to the following observations;

- The total costs for Option 3 in the Business Case for the AMI program are too low.

- The costs of the Victorian rollout is not particularly relevant as this was an early adopter situation with respect to lessons learnt and technology development and maturity.
- By including the revised NPV value of $36.6 million as an increase in the business case costs, the per unit meter costs are closer to a range expected given meter costs and communication network costs have come down over the last few years.
-
- The benefits for Option 3 are much lower compared with the estimated benefits for the overseas entities. The overseas entities though would include both financial and non-financial benefits to customers. Western Power in its business case has only factored in financial benefits for the network which have a downward trend on prices whereas non-financial benefits would have an upward trend.

Table 27 Comparison of various roll out case studies

Scenario	Option 3 w/o indirect costs	Option 3 With indirect costs	Option 3 With WP Revised NPV	Vic 2008 pre-rollout study full rollout	Vic 2011 Deloitte study full rollout	UK Smart metering program full rollout	Ameron Illinois full rollout	Con Edison full rollout	BC Hydro Full rollout
Cost base	A$2016/17	A$2016/17	A$2016/17	A$2008	A$2008	£2016	US$2012	US$2015	CAN$
Total costs per meter	453	487	518	684	1,412	429	404	468	584
Total benefits per meter	530	530	530	777	1,421	653	756	791	857
Meters (in millions)	1.18	1.18	1.18	2.65	2.65	25.6	1.15	3.55	1.9

Distribution network providers in other Australian states, other than Victoria, have not proceeded with a full rollout of advanced metering as the business case for doing so, according to these network providers, does not indicate a positive net benefit.

We consider that a more detailed review of the business case benefits is warranted based on this and the above observations. Furthermore if the financial benefits to Western Power and its network customers do not outweigh the costs, then a business case supporting the programme will have to be based on the sum of the financial and non-financial benefits.

10.2.3.4 Benefits

To undertake our analysis of the business case, only items with a benefit value greater than $10 million were reviewed. Table 28 contains the benchmarking overview for comparison of Western Power's advanced metering business case and other similar business cases and metering roll-outs.

Table 28 Benchmarking Overview – AMI Roll-outs and Business Cases

Item	Western Power NPV Benefit	Key Western Power Assumptions	Key Benchmark Report Assumptions
Deferred Network Investment	48.8 (S)	kW Demand specific Assumptions • $28 M NPV from kW demand reduction • 3 year delay to benefits • 25% of customers respond to TOU, increasing to 100% over 15 years. This suggests an assumption that there is a shift from opt-in to mandatory TOU tariffs. • 50% non-firmness adjustment • 5% demand reduction Power Factor-specific Assumptions • 5 MVA starting point for peak MVA reduction • 40% further reduction p.a. until 150 MVA reduction achieved • $95/kW assumed for transmission and distribution network deferral benefit • $20.7 M from power factor correction benefits • Capacitor cost 25% of benefits	• Ameren o 40% take-up (residential) o 3-6% take-up (commercial/industrial) • Deloitte o 4% take-up increasing to 15% o 1.5% peak demand reduction o 0.1% total consumption reduction o $200/kW • Futura o 80% take-up o 1.5% peak demand reduction • Oakley Greenwood o 30% take-up o 1.5% peak demand reduction • BC hydro o Build to 30% maximum o 11.5% peak demand reduction o 7.6% overall consumption reduction
Service Connection Monitoring	78.6 (S)	• Services connection replacements 12500 pa • Type 1 Avoided Capex - overhead service connection replacement $150 • Type 3 Avoided Capex - overhead service connection replacement $1297 • Proportion avoided per annum 30% • Duration of benefit 10 years	Not identified as a benefit explicitly

Item	Western Power NPV Benefit	Key Western Power Assumptions	Key Benchmark Report Assumptions
Call Centre Data	10.3	• Maximum 30% reduction in call centre costs • Cost reduction equal to advanced meter population % • Scale up to 30% over 7 years	• Ameren o 5% reduction in call volume • BC hydro o No assumptions given, $10 M estimate o 1.9 Million meters
Meter reads, Energisation / Deenergisation	33.3 (S)	• 4% reduction in scheduled meter reading efficiency • 1.9% of meter population requires re-energisation/de-energisation p.a.	• Deloitte o Higher benefits o 22% of meters require re-energisation/de-energisation p.a. • BC hydro o 95% of meters connected to IT for benefits from automated meter reading
Voltage Balance	39.4 (S)	• Technical loss reduction from 4.3% to 3.44%	• BC hydro o >2,000 commercial customers have sites where voltage optimisation could benefit them
Theft reduction	17.2	• Decrease from 0.75% to 0.38% (halved)	• Ameren o Decrease from 1% to 0.5% (halved) • Deloitte o Decrease from 0.5% to 0.25% (halved) • BC hydro o 10% of theft reduced • conEdison o 1-3% theft o 0.25% theft reduction

Item	Western Power NPV Benefit	Key Western Power Assumptions	Key Benchmark Report Assumptions
Avoided IT costs required otherwise	14.1	• System upgrades and communications solution investment associated with Distribution Automation would otherwise be necessary. • Use of the communication infrastructure provides for multiple business communications requirements, but can be leveraged for additional unregulated revenue from third parties.	Not explicitly identified

The following items were identified for further analysis on the basis of notable differences in assumptions between those used by Western Power and those used by other network operators in their business cases and in other publically available reports:

- deferred network investment
- reduced service connection costs
- reduced call centre costs
- improved voltage balance
- avoided IT costs

Each of these are explained in more detail below.

10.2.3.4.1 Deferred network investment

There is little growth forecasted in demand for AA4, and Western Power indicated to us that they were constantly reviewing their project portfolio to decide what expenditure is efficient. Recognising that AMI will help in identifying localised demand patterns, we can appreciate that any data retrieved would certainly improve the knowledge of demand patterns in the network, but question whether it is appropriate to capture deferral in expenditure in the business case for the AMI program due to the improved data available from advanced meters. For example, such data could better inform the management of risks which could require the opposite and bring forward expenditure. In short we do not agree that it is reasonable for the AMI program to be credited with network augmentation deferral due to better granular and localised knowledge of demand.

The calculation for deferred peak demand reduction due to time-of-use (TOU) tariffs seem reasonable compared with other rollout examples, except for the take-up rate. The take-up rate increasing from 25% to 100% by end of the program appears to assume a shift from Opt-In to Mandatory TOU. The take-up rate is outside Western Power's control, and sensitivity to this assumption should have been tested.

We have reviewed the assumptions for kW demand reduction per customer with TOU metering and the $/kW value of deferral and consider these should be reduced by an amount to allow for the risk of less than a 100% TOU take-up.

The reduction in costs due to power factor correction benefits is questionable. We believe there should be no reason why Western Power could not install 11 kV feeder located capacitor banks without smart meters to achieve the benefits if they outweigh the costs. A switch to kVA demand tariffs for commercial and industrial customers will drive the installation of capacitor banks by the customer. Thus in this case costs should not be included, but the benefits could be included.

Western Power had attributed $28 million benefit (discounted) to kW demand reduction due to TOU metering and $20.7 million to power factor correction benefits. We have reduced the power factor correction benefit to about one half of the amount assumed by Western Power in its business case as the benefits could be achieved without advanced metering.

- $10 million reduced NPV benefit for kW demand reduction
- $10 million reduced NPV benefit for power factor correction

10.2.3.4.2 Service connection monitoring

The new strategy and savings for consumer connection inspections and replacement program is based on the ability of smart meters to monitor the condition of the overhead service connections. Issues with consumer connection to a premises can only be detected by a smart meter located at the premises. For all connections to be totally monitored, a complete roll out would be required.

Hence reduced replacement and inspection expenditures in the early years will marginally increase risks of electric shocks and failures compared with the current replacement program continuing. Western Power has proposed to move to a treat on failure strategy and gradually move to treat on condition via the ability of the AMI to provide this benefit.

It may be a reasonable risk to not continue the program of replacement on age while the population of meters increases on the network; however, in this case the benefits cannot be attributed to the smart meter roll out. We recommend the start of the benefits should be deferred 3 years.

- $25 million reduced NPV benefit (78.6 million reduced by an estimated 32% in NPV benefit)

10.2.3.4.3 Call centre costs

A reduction in call centre costs are assumed as to be equal to a percentage of smart meters installed and up to a cap off 30% over 7 years. The percentage assumed is higher than assumed by other roll outs. A 5% reduction in call volume was expected by Ameren Illinois following a completed roll out of their advanced metering program. BC Hydro assumed a reduction of around one half that of Western Power's assumption. We recommend that the benefit Western Power is seeking to obtain through a reduction in call centre costs be reduced by one half.

- $5 million reduced NPV benefit

10.2.3.4.4 Voltage balance

The benefits associated with voltage balancing are defined as "*… through better access to data that enables improved balancing between phases, voltage management and power factor correction.*"

Western Power has calculated the benefits as reduced technical losses only. Power factor correction improvement has already been included under deferred network investment benefit. Western Power assessed technical loss reduction reducing from 4.3% to 3.44% of system losses once the total population of meters are changed to advanced meters. The UK Smart Meter Roll-Out Cost-Benefit Analysis identified technical loss savings at $28.2 million, after converting to Australian dollars and adjusting to Western Power's meter volumes. BC Hydro in trials of AMI found that they could achieve 6-7% reduction in peak demand through improved voltage balance. A reduction of 7% in peak demand would result in savings in losses of 13.5% compared to Western Power's reduction assumption of 20.7%. This would reduce the NPV benefit to $25.6 million.

- $13.4 million reduced NPV benefit (voltage balance benefit reduced from $39.4 million to $26 million)

10.2.3.4.5 Avoided IT costs

Western Power has included IT savings in the business case for avoided communication system costs that would have otherwise been required to capture unregulated revenue opportunities and for automating the distribution network.

Unregulated revenue should not be included as a benefit to be covered by regulated revenue and distribution automation should not be included as customers are indicating that reliability of the network is already reasonable.

- [redacted]

[redacted]

10.2.3.4.6 General assumptions within the business case:

The following general assumptions are applied in the business case:

- 1.5% demand growth
- 2.5% consumer price index (CPI) (in contrast to use of 1.64% in the regulatory revenue model and use of 2.4% pertaining to labour cost escalation, as forecast by the Reserve Bank of Australia (RBA))
- 2.5% labour escalation (in contrast to use of a nominal ~3.4% labour escalation for OPEX, which combines the 2.4% CPI escalation with a real labour escalation of 1.0%)

Table 29 Summary of benefits and meter volume adjustments

Benefit	Original Business Case	Option A Reduced BAU Meter Volumes/Original AMI Volumes/Reduced Benefits	Option B Reduced BAU Meter Volumes/Reduced Business Case Volumes [66] and benefits
Deferred network investment	48.8	28.8	26.6
Service connection monitoring	78.6	53.6	53.6
Call centre cost savings	10.3	5.3	5.1
Voltage balance	39.5	26	20.7
Avoided IT cost	14.1	0	0
Other Benefits (not reviewed)	171.2	171.2	163.5
PV Benefits	362.5	284.9	269.5
PV Incremental Costs	307.6 [67]	319.6 [68]	307.6 [69]
NPV	54.9	-34.7	-38.1

We noted that the some benefits types had no or little linkage to the number of smart meters installed in the cost benefit analysis, namely; deferred network investment, service connection monitoring and call centre cost savings. For most benefits types, we would expect the savings to be proportional to the number of meters installed. Adopting this approach will result in a greater downward adjustment of benefits.

Two of the reviewed international rollouts (UK and BC Hydro) provided a breakdown of the benefits assumed in those rollouts. The benefits could be divided under consumer benefits, metering benefits, network benefits and generation benefits. These rollouts looked at the total societal benefits for the rollout programs but did

[66] The accuracy of the results is questionable as the business case cost benefit analysis does not adequately link benefits with installed number of advanced meters

[67] Calculated as 271.0 + 36.6

[68] Calculated as 271.0 + 36.6 + 12.0

[69] Calculated as 271.0 + 36.6

not address how all of the value would be achieved under the respective market models. There were notable differences, on a per meter basis, between the Western Power forecasted savings and those of BC Hydro and the UK rollouts. Savings in meter reading costs in the UK rollout were much higher than Western Power and BC Hydro. Savings in non-technical losses (theft) was much higher for BC Hydro compared with Western Power and BC Hydro. Table 30 indicates the comparison between rollout programs after adjusting for these significant differences.

Notable insights from the comparison:

- The assessed benefits in different rollouts can be significantly different at the granular level
- Network benefits in both cases where not as high as Western Power's assessed benefits, and in particular the UK AMI rollout attributed a relatively much smaller amount per meter to network benefits.
- Western Power has only included metering and network benefits in its business case. We consider it to be reasonable for Western Power only to capture benefits with respect to its covered network services in its business case.
- Our adjustments have reduced the Western Power network benefits from $220 per meter to $138 per meter which also is more comparable to the benefits assigned by BC Hydro to network benefits. Arguably the benefits should be greater for BC Hydro given that Western Power's rollout is over 15 years or longer.
- The adjusted Western Power total benefits (comprising metering benefits, Network benefits and non-technical loss reduction benefit) of $459 per meter is now less than the costs of $518 per meter as shown in Table 27.
- If the full value chain of benefits, such as the following non-network benefits, are analysed and included, then the business case may show a positive outcome.
  - Consumer benefits; microgeneration and energy management, and
  - Generation benefits; demand management and avoided generation capacity

International rollouts of AMI in vertically integrated utilities capture all of the benefits across the supply chain from generation to consumers. This is identical to the "Supply Chain Cost Test" in assessing demand management options in the Australian electricity markets.[70]

Table 30 shows two rollout case examples where the size of generation benefits are illustrated.

Western Power could assess these benefits under Section 9.1(a) of the Access Code. Section 9.1(a) of the Access Code states that one of the objectives of Chapter 9 is "*… to ensure that before a service provider commits to a proposed major augmentation to a covered network, the major augmentation is properly assessed to determine whether it maximises the net benefit after considering alternative options.*"

The term "net benefit after considering alternative options" is defined in section 9.4 of the Access Code as "*… a net benefit (measured in PV terms to the extent that it is possible to do so) to those who generate, transport and consume electricity in the covered network and any interconnected system, having regard to all reasonable alternative options, including the likelihood of each alternative option proceeding.*"

[70] Energetics, *Western Power DM Screening Tool - Supplementary Report*, 9 December 2016, section 3.1, pp. 5-6

Table 30 Comparison to international AMI rollout benefits[71]

Benefits	WP Adjusted ($A per meter)	UK AMI ($A per meter)	BC Hydro AMI ($A per meter)
Consumer Benefits	-	230	116
Metering Benefits	296	293	173
Network Benefits	138	45	126
Non-technical losses	15	10	40
Generation Benefits	-	106	174
Total PV Benefits	449[72]	684	629

10.2.3.5 Conclusions

From our analysis we conclude the following:

1. The BAU volume for new and replacements meters should be reduced from 355,493 to 273,493 due to 54,000 less meters for compliance-driven replacements and 28,510 less new meters for growth. This is a 23% total reduction in meter volumes. Should the same volumes be retained for the business case then the PV of the loss of remaining life of the replaced meters would be $12 million (refer section 10.2.3.1). This would be added to the cost of the AMI business case.
2. The costs in the Western Power AMI business case appeared low when initially compared with other AMI rollouts. Western Power revised the business case and reduced the NPV by $36.6 million. If this was assumed to be an increase in costs this increase would result in the costs being more comparable, but still low, with other AMI rollouts when converted to a PV cost per meter basis (refer Table 27).
3. We have reviewed the benefits identified by Western Power in the Business Case and our assessment is that the value of benefits should be reduced from $362.5 million to $279.5 million (and may potentially reduce further). Our adjustments have reduced the Western Power network benefits by reviewing individual benefit types and comparing benefits with other comparable AMI rollouts.
4. The NPV has reduced from +$91.5 million in the original business to -$38.1 million (refer Option B in Table 29) after the following adjustments for additional costs and reduced benefits;
    a. $36.6 million reduction in NPV applied by Western Power added as additional costs
    b. $12 million from loss of meter life if the current business case meter volumes are retained
    c. $103 million from reduced network benefits
5. Western Power identified non-network benefits however these were not all valued in the business case. The term "net benefit after considering alternative options" is defined in section 9.4 of the Access Code as "*… a net benefit (measured in PV terms to the extent that it is possible to do so) to those who generate, transport and consume electricity in the covered network and any interconnected system, having regard to all reasonable alternative options, including the likelihood of each alternative option*

[71] Based on $1 Canadian = $0.98 AUD; £1 GBP = $0.575 AUD

[72] Includes BAU metering costs as an avoided cost benefit for comparison purposes with other AMI rollouts

proceeding." We have not valued these benefits to assess whether the business case could be justified.

The implication is that under Section 6.52(b) the review of the business case in its current form does not satisfy one or more of the following three criteria (test) of NFIT:

1. The anticipated incremental revenue for the new facility is expected to at least recover the new facility investment.
2. The new facility provides net benefits in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs.
3. The new facility is necessary to maintain the safety and reliability of the covered network or to provide contracted covered services.

In developing their business case, Western Power has not provided evidence of sensitivity analysis of their key assumptions. Undertaking this analysis on candidate options would be beneficial, as it would provide confidence in the assumptions used and determine the amount of effort needed to accurately quantify assumptions. In turn, sensitivity analysis would enable more confidence to be placed in business case and assist Western Power in making a robust investment decision. Western Power did not provide clear details of each type of benefit determined in the cost benefit analysis which made it difficult to review the assumptions.

The Advanced Metering Business Case as presented does not meet the requirements that "… *the new facility provides net benefits in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs*".

Western Power could value the identified non-network benefits as allowed and defined as net benefits in section 9.4 of the Access Code. For both network and non-network benefits, the estimates of benefits should demonstrate an expected accuracy range of ±30% with sensitivities analysis included on key assumptions.

We have made adjustments to the CAPEX expenditure based on the reduced metering volumes allowing for deployment of 'advanced capable' meters in all new and replacement situations, and removed the investment in information technology systems and communications infrastructure to support advanced metering (Business Case Option 2). The additional 2.2 million per annum allowed for maintenance of the communication infrastructure has also been removed.

We have identified $40 million to be removed from the AA4 expenditure and recommend ERA requests Western Power to otherwise justify this expenditure related to ICT infrastructure for the AA4 period with respect to the AMI Business Case. The $40 million is split between "incremental IT Capex allocation" ($15 million) (refer Table 68) and "incremental SCADA/Comms Capex allocation" ($25.11 million) (refer Table 39) as identified as related to the advanced metering business case in Table 59.

10.2.4 State Underground Power Program (SUPP)

It is noted that Western Power receives significant funding for the State Underground Power Program (SUPP) and there has been work previously undertaken by the ERA to demonstrate that the level of customer funding is consistent with the requirements of the NFIT. It is also noted that the SUPP is subject to the IAM and the proposed levels of expenditure are reasonable in relation to historic levels.

As such we consider the forecast expenditures for this cost category to be reasonable, and recommend these are accepted.

10.3 Compliance

10.3.1 Pole management

This expenditure category includes consideration of cross-arm and stay system replacement. The AA4 distribution CAPEX includes an allowance of $40.5 million.

Wood poles, cross-arms, stays and insulator replacements are classified as high risk assets. The enterprise risk assessment criteria identifies that high risk items are monitored and reviewed quarterly by the Executive and six monthly by the Board/Executive.

As at 30 June 2016, Western Power has identified 18,379 cross-arms as being defective and 8,419 stay systems that require replacement. The NMP notes that the common failure mode for cross-arms is splitting for wood types and corrosion for steel, whilst corrosion and under-rating is the most common failure for stay systems.[73] The replacement strategy for these assets is based on condition:

- Cross-arms are replaced on condition assessment, with no replacement of poles in fair condition with defective cross-arms
- Replacement of stay poles and stay systems on condition assessment where these are located in extreme and high fire-risk zones and very high and high public zones. In all other locations, the stay poles and stay systems that have been assessed for replacement by their condition are only replaced when the main pole is replaced
- Loose stays are repaired

10.3.1.1 Volumes

The cross-arm replacement program was previously included in the bushfire management category. From the NDP[74], the planned replacements for AA4 are:

- 4,379 cross-arms and 25,012 insulators as part of risk based renewal methodology
- 3,128 stay systems
- silicone insulators of 96,022 structures with priority based on high pollution and high fire risks

As a result of these replacement rates, unassisted asset failures per annum are projected to rise for cross-arms from 442 at 30 June 2016 to 514 by the end of AA4 and 465 by 2027, and for stay systems, from 115 at 30 June 2016 to 152 by the end of AA4 and 144 by 2027.

As discussed for wood pole management (refer section 10.2.1), an increasing unassisted failure rate is based on historic failure rates, and is affected by the quality of asset information available and the criticality of the asset. The assessed overall risk for distribution structures is High at 30 June 2016, High at the end of AA4 and High by 2027; that is, the proposed volumes do not change the risk profile by risk type or the overall risk ranking (refer section 10.2.1.1).

This is consistent with the Western Power corporate goal of reducing expenditure to a level considered efficient whilst maintaining network risk at current levels. We accept the forecast volumes, assuming Western Power has assessed the condition of cross-arms, insulators and stay systems, but as for wood pole management, we would expect that Western Power will not allow safety or the risk profile of the current

[73] Western Power, *Network Management Plan: Transmission and Distribution Network 2017/18 - 2027/28*, August 2017, section 5.5.1, Table 131, p. 140

[74] Table 5, p. 14

cross-arm and stay system population to be compromised should condition assessment recommend replacement in volumes beyond those forecast, particularly given that the current replacement volumes project a potentially higher risk profile by the end of AA5.

10.3.1.2 Costs

We have based on our estimated unit rates for the following activities on standard job estimates we have available, based on standard industry costs:

- replacement of a cross-arm
- replacement of insulators
- replacement of stay systems
- siliconing of existing insulators

Our comparative estimate for this work is $42.98 million, which is approximately 6% higher than that proposed by Western Power for AA4, which is within our nominal ±15% test for reasonableness.

We recommend the Western Power proposal of $40.5 million is accepted, based on the volumes of work that have been estimated for AA4.

10.3.1.3 Performance measurement

Similar to the performance measures for wood poles (refer section 10.2.1.3), we note that electricity distribution entities within the NEM have differing performance indicators for their wood pole management programs, although we have not identified many specific to the pole-top assets.

Consistent with the wood pole performance measures we have identified in section 10.2.1.3, we recommend that Western Power reports the following performance measure as an output of the pole-top management program:

- unassisted cross-arm failure rate as % of total population → quality/outcome measure

10.3.2 Bushfire management

The Western Power bushfire mitigation strategy is to "*… develop a network that is built and maintained in a manner to eliminate fire ignition risks so far as is reasonably practicable, and if it is not reasonably practicable to do so, reduce those risks to as low as reasonably practicable.*"[75]

The objectives[76] of the strategy are:

- to mitigate and prevent high consequence fires
- to manage ground fires across the network at or below the historical levels of performance

Western Power has four categories of bushfire risk zones - Extreme, High, Medium and Low.

Most of the Western Power SWIS is rated a Moderate FRZ or higher. 77% of the distribution network and 60% of the transmission network are regarded as being located in Moderate and Low bushfire risk zones, with the remainder in Extreme and High bushfire risk zones.

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[75] Western Power, *Bushfire Mitigation Strategy (Transmission and Distribution)*, 1 August 2017, section 1, p. 6

[76] In the *Bushfire Mitigation Strategy*, Western Power notes that maintaining AA3 performance into AA4 is consistent with the results of the customer engagement program regarding customer sensitivity to price rises and the price increases that may occur if the objective was to improve overall network performance. One of the key insights from the customer engagement program was that customers want to see bushfire safety investment targeted in areas where the impact is greatest.

For AA3, the original planned expenditure included the replacement of 1,500 km of overhead line where the conductor was assessed to be in poor condition with the potential of falling, reducing 8,900 long conductor spans, installation of 16,000 conductor spreaders to reduce the possibility of conductor clashing, and replacing 15,700 defective pole top assemblies.

Expenditure on bushfire management was $39.13 million (including indirect costs and real escalation) over the AA3 period, which was 12% of the total regulatory compliance spend. This was 44% lower than the approved AA3 after Western Power implemented strategy changes leading to a more efficient targeting of clashing conductor risk. The work completed included the replacement of 3,980 pole top assets and the installation of 4,039 LV conductor spreaders. During AA3, Western Power assessed the deployment of reclosers was a more effective and efficient means of mitigating bushfire risk due to conductor clashing than redesigning long conductor spans.

In the NMP, the planned activities for AA4 are the installation of 2,500 LV conductor spreaders and 132 reclosers placed to increase coverage for clashed conductor detection and addressing 414 HV conductor clashing conditions. In addition, Western Power has identified that with 29% (8,897) expulsion drop-fuses are installed in Extreme and High bushfire risk zones, pole base clearing activity is required to reduce the risk of fire due to the operation of these drop-fuses.

To minimise the potential for fire from conductor clashing or failure, Western Power employs an Auto-Reclose Minimisation scheme during the designated bushfire season to limit auto reclosing to a single operation lockout in Extreme and High bushfire risk zones.

Western Power has proposed a total of $25.9 million (excluding indirect costs and real escalation) for bushfire mitigation activities during AA4, which is 34% less than that incurred during AA3. The targeted deployment of electronic reclosers is considered a reasonable response in line with standard industry practice - one of the key recommendations of the 2009 Victorian Bushfire Royal Commission related to the use of electronic reclosers and that the network operator "*… adjust the reclose function on the automatic reclosers … on all total fire ban days to permit only one reclose attempt before lockout*." Therefore, we accept that the approach Western Power has adopted for AA4 is consistent with recommended practice for bushfire mitigation by electricity utilities.

The key insights from the Bushfire Mitigation Strategy highlight that there has been a lower number of ground fires in the last 4 years, and that the severity of ground fires has decreased. There has also been a reduction in the number of pole top fires and unassisted conductor clashes due to asset replacement investment during AA3.

We are satisfied that Western Power has improved its bushfire management during AA3, and recommend the proposed $25.9 million for AA4 is accepted.

10.3.3 Conductor management

In order to verify if there are any double counting or overlap between the projects that forms or constitute the conductor management program (within the Distribution Asset Replacement) and this program within the Distribution Compliance, we reviewed the details of this proposed expenditure.

10.3.3.1 Business Case

This proposed investment is estimated at $7 million (excluding indirect costs and excluding real cost escalation) and is targeted to address existing substandard clearance issues. The profile of this expenditure is based on the high risk overhead span forecasted to be remediated over the AA4 period. Overhead spans are identified based on inspection data and prioritised using a risk based approach that includes assessment of likelihood of the event (contact by a third party to live conductors) and the consequence from the event.

Cost estimates and volumes are based on the average historical performance during AA3. The solutions employed to solve conductor substandard clearance issues vary in complexity from installation of taller pole/s to a full design which may include adjacent overhead span.

10.3.3.2 Assessment

In order to assess the reasonableness of the proposed expenditure, we reviewed the following information:

- Details of the residual risk rating (likelihood and consequence) of the distribution overhead conductor for likely hazards (fire, shock, physical contact etc.). Western Power assesses the safety risk of electricity network assets in three categories, namely - physical impact, electric shock, and fire. The interference with electricity network assets can be with or without electricity discharge from the network. Risk of injury or property damage from incidents that result in electric shock are covered under the ‘electric shock’ hazard category. Similarly, the risk of injury or property damage from incidents that do not result in electric shock are covered under the ‘physical impact’ hazard category. Conductors with substandard clearances present an increased likelihood of coming into contact with vehicles, people or livestock. This has the potential to cause injuries from both physical impact and electric shock. In summary, the history of ‘physical impact’ and ‘electricity shock’ are quiet low (one animal died in last 3 years) and thus are not the driver of this investment. However, there is a history of ‘fire’ and this reason can alone be the driver of this investment.
- Strategy/program for managing risks due to substandard clearances of distribution overhead conductors available in AAI and the NMP documents.
- Application of the AS/ANZ 7000:2010 design standard retrospectively to address substandard clearance issues with the old/existing assets before their natural retirement time. It is noted that Western Power’s AA4 program only targets the remediation of a subset of all identified substandard clearance conductors, prioritised by the risk that they present (considering the safety risks of electric shock and physical impact). This program does not aim at 100% compliance. The remedial solutions applied conform to the requirements of AS/NZS 7000:2010, and aim to optimise the whole of lifecycle costs. The options for remedial solutions includes, but are not limited to:
  - re-tensioning of the conductor
  - lifting conductors on same pole by changing position of the point of attachment of the conductor to the pole
  - raising the conductor on a new intermediate pole
  - replacing existing pole(s) with taller pole(s)
  - undergrounding the affected span(s)
- Possibilities of the avoiding the identified hazards by other control measures (such as administrative process, building barrier, fencing, warning signs before its replacement in natural course of time) which are cheaper than the proposed expenditure.

10.3.3.3 Conclusion

We recommend accepting the proposed expenditure level for this program. We also gained an appreciation of this compliance program and do not consider any overlap or double counting between this expenditure budget and the conductor management program within the Distribution Asset Replacement budget.

10.3.4 Reliability Compliance

10.3.4.1 Business case

This proposed investment is estimated at $18 million (excluding indirect costs and excluding real cost escalation) and is targeted to address or troubleshoot poor performing feeders. The aim of this investment is to lower the network wide overall reliability performance metric averages. It is noted that 10-15 issues are targeted in the next 5 years, which is approximately $1.5 million per issue.

Western Power's approach to reliability is contained in the Distribution Reliability Strategy document. This proposed program is a portfolio of projects designed to target reliability issues and provide focussed improvement in areas experiencing poor performance that is well below the network wide average or where reliability does not meet minimum service level standards.

10.3.4.2 Assessment

Western Power's Distribution Reliability Strategy document does not list any specific projects within this program. We noted that troubleshooting reliability issues often involves frequent inspection and maintenance cycle, clean-up, pest control (i.e. OPEX) and thus assessed this proposed expenditure to ascertain CAPEX justification.

We also assessed this investment to understand the details and the corresponding cost of the proposed solutions and if there is any overlap or double counting with the similarly labelled 'Dx reliability other' program within the distribution improvement in service CAPEX category.

We reviewed and noted the following:

- This is not for asset replacement (to address poor condition) or operational expenses such as vegetation management.
- Projects in this CAPEX program would typically include activities such as:
  - the installation of reclosers or other protective devices and setting changes
  - network augmentation (e.g. new or upgraded feeder sections, and new assets such as automated RMUs)
  - additional targeted replacement works (e.g. poles and conductors) that provide a specific reliability benefit
  - the installation of emerging technology (e.g. fuse savers, battery energy storage)
- Maintenance activities or operational expense may also be deployed to address poor performing feeders (or reliability hotspots). However, these types of activities would be considered as OPEX and not funded by this proposed CAPEX program.
- Western Power monitors reliability 'Hot Spots', which are areas of the distribution network that experience below average reliability performance with respect to duration and frequency of supply interruptions. The worst performing network segments or feeders are prioritise for this program with an aim to provide the best reliability performance return for the investment made.
- Issues and incidents in these poor performing network segments are investigated and resolved through a combination of reactive, proactive and sustaining activities that are linked to different time horizons in the short term, medium term and long term. The underlying objective for all three approaches is to limit the frequency of interruptions, the impact on customers, and the duration of supply interruptions while maintaining efficiency.

10.3.4.3 Conclusion

We are satisfied with the proposed expenditure level for this program. We also gained an appreciation of this compliance program and do not consider that there is any overlap or double counting between this expenditure budget and the similarly labelled 'Dx reliability other' program within the distribution improvement in service CAPEX category described in Section 10.5.

The 'Dx reliability other' category comprises of projects intended to maintain current levels of reliability performance and in some cases improve reliability performance at minimal cost by leveraging on Western Power's existing automated devices. An example of this is the Hay Mil CBD RMU automation project. This project is proposed to ensure Perth CBD reliability performance is maintained over the course in AA4 period. The Kalbarri microgrid project is another project in this category.

10.4 Growth

10.4.1 Business case

Western Power has proposed $508 million (real June 2017, excluding indirect costs, excluding real labour cost escalation) during the AA4 period for customer driven distribution growth network CAPEX. Western Power states (in attachment 8.1) that it includes all work associated with connecting customer loads or generators, and the relocation of distribution assets at the request of a third party. Such projects range from small residential connections (pole to pillar), through to network extensions to cater for large industrial customers. This category of investment generally includes high volumes of low cost works and includes but is not limited to the following:

- Connection total $48 million (excluding indirect costs and real cost escalation)
- Major Capital total $101 million (excluding indirect costs and real cost escalation)
- Network Extension total $261 million (excluding indirect costs and real cost escalation)
- Relocation total $28 million (excluding indirect costs and real cost escalation)
- Subdivision total $60 million (excluding indirect costs and real cost escalation)

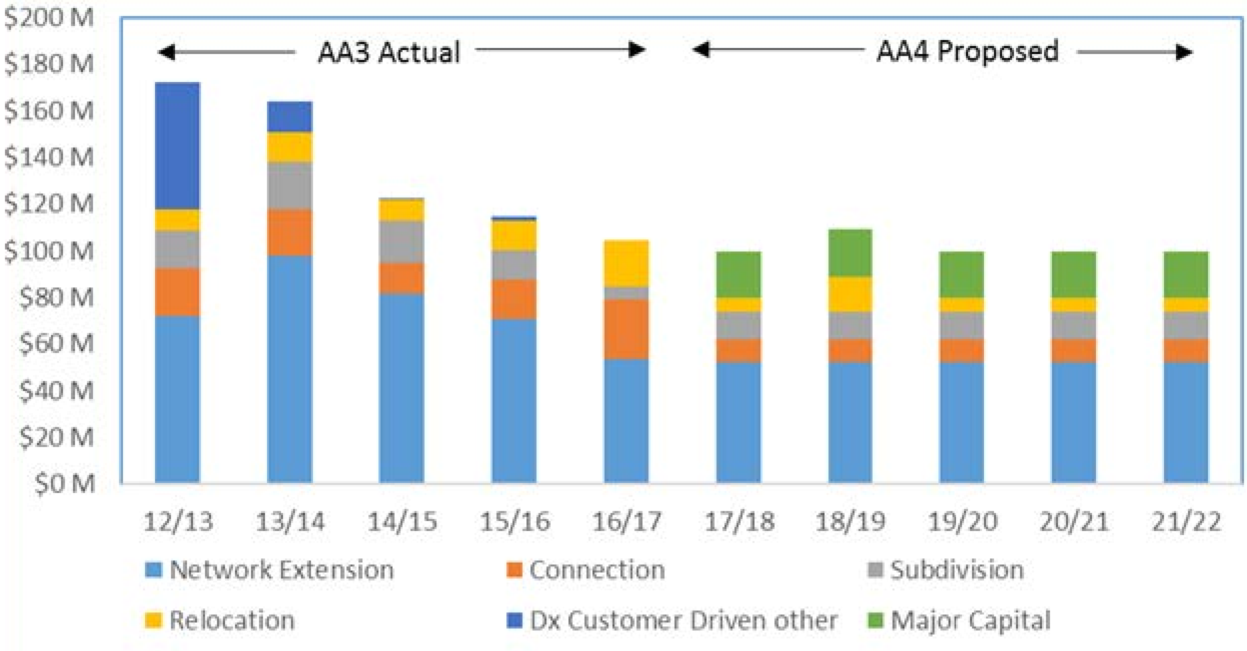
We noted that all the expenditure items proposed in this CAPEX category are forecast to incur at constant level for the next 5 years and not much of the detail build-up of these proposed expenditure is available.

10.4.2 Assessment

Unlike transmission growth CAPEX which by nature of its infrastructure consists of low volume-high value assets or projects, these types of distribution growth CAPEX consists of high volume of low value jobs. Each such individual jobs are not visible to a business in greater advance and therefore cannot be specifically described like individual transmission growth projects at this stage. Understanding of specific or individual job becomes clearer closer or nearer to the actual delivery requirement. While it is usual for a business to know that they have to deliver such jobs, they can only estimate the volume of such jobs in advance based on historical experience and the immediate regional economic outlook.

In absence of documented information supporting the basis of this proposed expenditure level, we queried the rigour that has been applied in determining this expenditure level. Comparison to previous AA3 actual with the proposed level for AA4 is not a measure of efficient budget build-up. Western Power has indicated that the business cases (need statement, credible solutions, option analysis, cost estimates, preferred solution) for proposing such programs and the basis for estimating them are not available and the forecast is based on high level extrapolation of historical experience. This historical and forecast trend is shown in Figure 30.

Figure 30 Distribution growth customer driven CAPEX ($M direct costs at 30 Jun 2017)

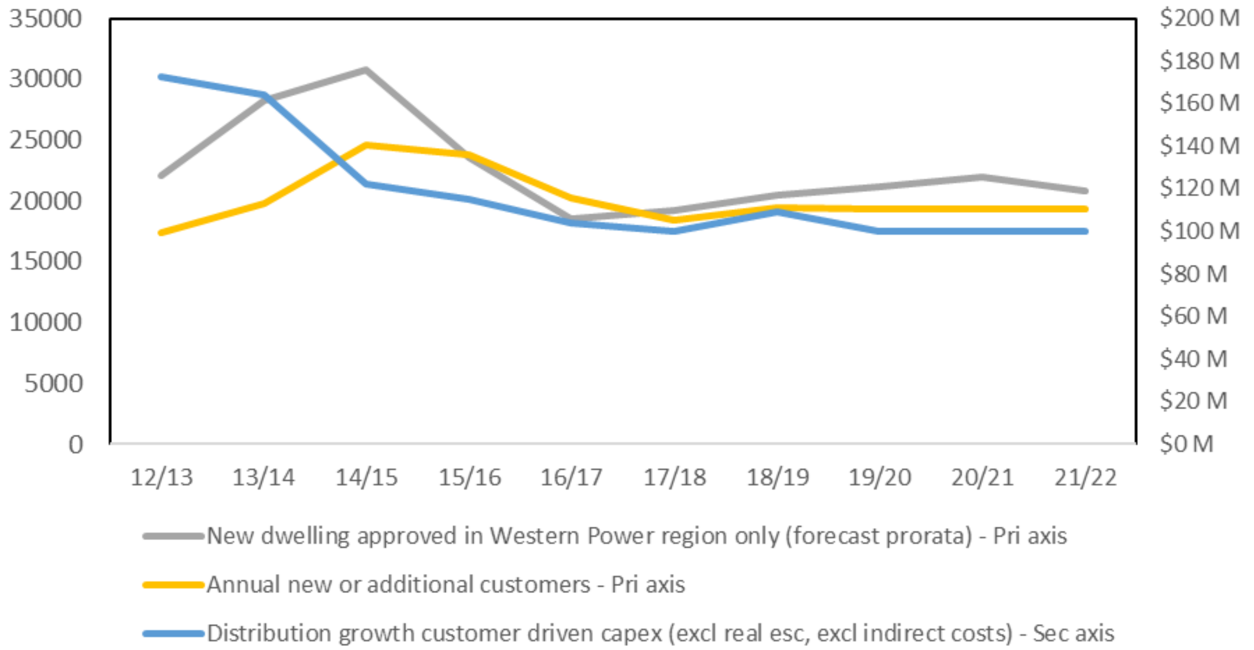


The development of this forecast is based on HIA forecasts, customer number, energy forecasts and historical trend analysis. Western Power's approach is to forecast this cost category as a whole and then allocate this total forecast into sub-categories of work (i.e. network extension, connections, etc.).

We requested historic and forecast trends of these econometric variables and reviewed how they compare with the historical and forecast expenditure trends with the purpose of determining the statistical correlation between these variable against the expenditure level.

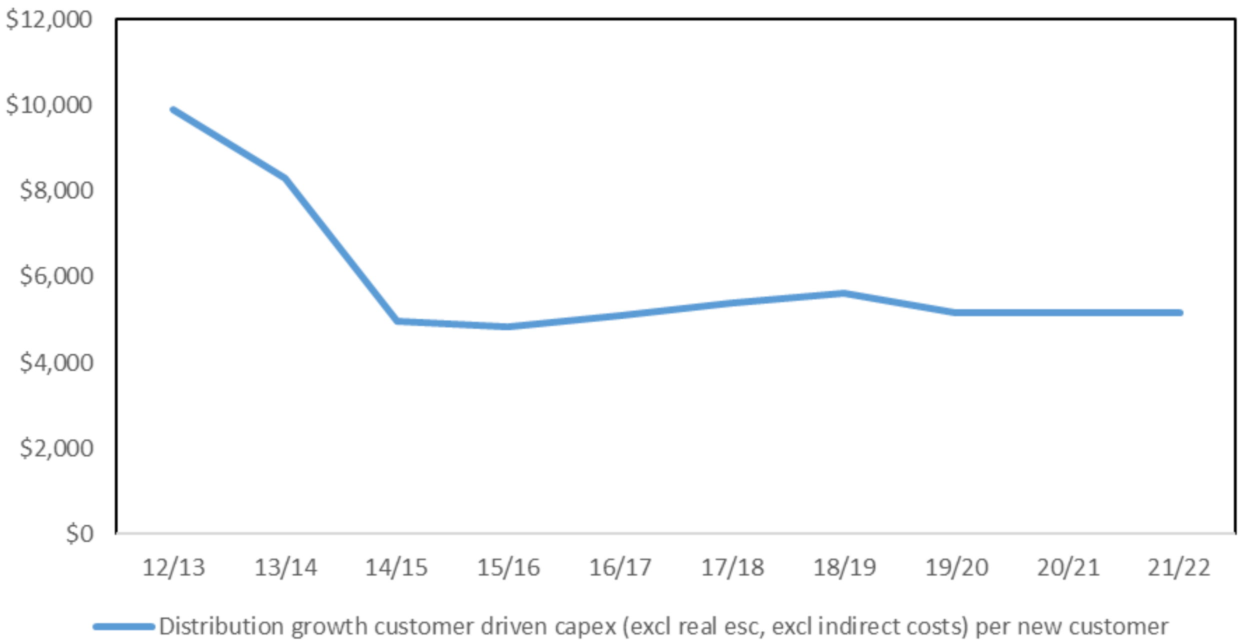
We examined the historical and forecast trends of CAPEX against the HIA dwelling growth and customer growth. The correlation or trend pattern match is as expected. The energy GWh growth trend was excluded from this statistical test as it distorts this comparison because Western Power has to still provide connection even if the GWh consumption is falling due to recent trend of solar PV intake offsetting the energy growth. This correlation is shown in Figure 31.

Figure 31 Distribution growth customer driven CAPEX trend vs econometric variables ($M direct costs at 30 Jun 2017)



We also looked at the historical actual expenditure level of this cost category and note that Western Power's expenditure was relatively high 2012/13 and 2013/14, followed by declining actual volumes and expenditure from 2014/15. Western Power considered the recent most three years to be the reflective of the growth outlook and therefore utilised a three-year historical average in place of a five-year historical average. This historical annual average is approximately $114 million. This historical average was validated internally with relevant stakeholders in Western Power and externally against the independently sourced econometric variables identified above. Western Power then applied a 10% efficiency adjustment to reflect expected process improvements flowing on from the Business Transformation Project. This brought the annual spend down to approximately $103 million (which aligns with the 2016-17 financial year actual). This is illustrated in the following graph which charts the cost per new customer for this distribution CAPEX category.

Figure 32 Distribution growth customer driven CAPEX trend per new customer rate ($M direct costs at 30 Jun 2017)



We compared the proposed new customer cost with other Australian DNSPs in the NEM (i.e. total connection and augmentation cost per new customer) and found the proposed rate to be reasonable.

Any changes in expenditure as a result of significant increases in customer demand will be addressed via the IAM in AA5.

Also, the proposed $101 million forecast labelled as 'Major Capital' within this CAPEX category is neither explained in Western Power's documentation nor is it recorded in the AA3 historic CAPEX. Upon query, we now understand that, following a number of changes to business processes through Western Power's BTP in the customer-funded space, accountabilities for the delivery of customer driven projects have changed. There are now different areas of Western Power responsible for 'simple' vs 'complex' customer projects. This has led to the creation of a new sub-category of expenditure 'Major Capital' that represents CAPEX on larger, complex projects that was historically included across a range of other categories (e.g. 'other' and 'connections'). There are a number of known projects in the early years of AA4 (including connection of distribution generators, Perth City Link and undergrounding projects outside of SUPP); however, beyond the early years it is not possible to forecast the exact projects and so a historical rate of spend has been applied. As a result of this re-categorisation, some of the sub-categories will show a variance when compared to the AA3 volumes of the sub-category.

10.4.3 Conclusion

We recommend accepting the proposed amount for this CAPEX category.

10.5 Improvement in service

Table 56 shows a comparison of the expenditure approved and incurred for AA3 and the proposed forecast expenditure for AA4 (including real cost escalation and indirect costs).

Table 31 Comparison of AA3 and AA4 service improvement CAPEX ($M real at 30 June 2017) [77]

Regulatory category	AA3 approved	AA3 actual	AA4 forecast
Reliability driven	3.36	6.57	23.10
SCADA & Communications	32.36	18.01	90.19
Total	**35.72**	**24.58**	**113.28**

Table 57 shows the total proposed forecast service improvement CAPEX (including indirect costs and escalation) during AA4.

Table 32 AA4 total proposed service improvement CAPEX ($M real at 30 June 2017) [78]

Regulatory category	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Reliability driven	5.08	10.61	3.22	2.09	2.10	23.10
SCADA & Communications	22.77	24.07	15.68	14.73	12.94	90.19
Total	**27.85**	**34.68**	**18.90**	**16.82**	**15.03**	**113.28**

Table 58 shows the proposed forecast service improvement CAPEX (direct costs only) during AA4.

Table 33 AA4 proposed service improvement CAPEX ($M real direct costs at 30 June 2017) [79]

Regulatory category	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Reliability driven						
Dx reliability	2.99	7.65	1.51	0.50	0.50	13.15
R&D Pilot projects	0.10	0.10	0.10	0.10	0.10	0.50
TRDA	1.11	1.11	1.11	1.11	1.11	5.55
SCADA & Communications						
Asset replacement	3.91	5.16	7.57	7.41	8.20	32.25
Core infrastructure growth	0.22	-	-	-	-	0.22
Corporate	10.45	10.45	1.55	1.65	1.01	25.11
Master station	4.23	4.50	4.13	3.01	1.33	17.20
Total	**23.01**	**28.97**	**15.97**	**13.78**	**12.25**	**93.98**

[77] Western Power Excel model *10.4 - AA Regulatory Revenue Model,* worksheet *Dx_Inputs,* rows 112 to 156

[78] Western Power Excel model *8.3 - Western Power AA4 capital expenditure and capital contribution model,* worksheet *Capex calcs*

[79] Ibid.

10.5.1 Kalbarri microgrid project

Kalbarri is a small community located at the northern edge of the South West Interconnected System (SWIS), and is currently supplied via a 150 km 33 kV radial feeder from Geraldton substation. This feeder is considered one of the worst performing feeders in the SWIS, and is subject to several environmental factors, due to the proximity of the feeder to the Western Australian coastline.

There is an existing Synergy windfarm that currently cannot supply Kalbarri during an outage on the line due to the existing network configuration.

In examining the possible solutions to providing more reliable supply to Kalbarri, Western Power considered their long-term view on network configuration, and the following possible augmentation options:

a. undergrounding the existing Geraldton - Kalbarri (GTN-KBR) feeder

b. replacing the existing conductor with Hendrix covered conductor

c. extension of the existing Northampton feeder

d. installing a microgrid based on:

- diesel power station
- battery energy storage system (BESS)

e. increased maintenance effort on the existing 33 kV GTN-KBR overhead line

Following community engagement, and discussions with the Mid West Development Commission, Western Power decided that the preferred solution should consider the use of renewables and not diesel, and should include the existing Synergy windfarm.

With reference to Appendix A, the optimal solution proposed by Western Power is the installation of a BESS, with the existing 33 kV feeder retained and maintained to minimise outages, including applying silicone to pole-top insulators.

We have reviewed the feasibility study[80] for this project and concluded:

- The proposed solution is an appropriate solution to address the reliability issues associated with the existing 33 kV feeder. It makes best use of the alternate generation available through the existing Synergy windfarm, and is suitable for the changing seasonal maximum demand requirements for Kalbarri during peak tourist times.
- Using an internal GHD model for examining costs related to edge-of-grid power supply options, we estimated a capital expenditure of $10.88 million for the installation of the BESS which is within 15% of the Western Power proposed $9.5 million capital expenditure for this project. We are therefore satisfied that the capital estimate is reasonable.
- Reviewing the proposed solutions against a base case of constructing an additional 33 kV line from Geraldton (GTN) to duplicate supply to Kalbarri (KBR), we determined the comparative NPV values considering whole-of-life costs over a 30-year period as shown in Table 34.

[80] Western Power, *Attachment 6.3 Study into the feasibility of a microgrid at Kalbarri*, 2 October 2017

Table 34 NPV for Kalbarri supply options[81]

Option	30-year NPV based on industry std lives[82]	30-year NPV based on nominal 15-year lives[83]
Base case: construction of additional 150 km 33 kV GTN-KBR overhead line	- $ 53.79 M	- $ 53.79 M
Construction of 150 km 33 kV GTN-KBR underground cable	- $ 201.03 M	- $ 201.03 M
Installation of BESS in Kalbarri plus ongoing annual maintenance on existing 33 kV GTN-KBR overhead line	- $ 32.53 M	- $ 29.29 M

Details of the NPV analysis for these options are included in Appendix A.

We are satisfied that the option proposed by Western Power is reasonable, as it represents the best engineering solution to the current reliability problems being experienced by the Kalbarri community, has a proposed capital cost that is reasonable in comparison to an indicative estimate we prepared using a bespoke edge-of-grid supply model, and has a better 30-year NPV value than potential network augmentations.

We recommend the proposed $9.5 million CAPEX allowance is accepted as part of the Distribution Reliability regulatory activity forecast for AA4.

10.5.2 SCADA & Communications

The Western Power approach to distribution SCADA & Communications investment and operations has until recently been predominately reactive, with investment focused almost exclusively on repair of failed equipment. As a result, the current Western Power distribution SCADA & Communications equipment is in poor condition and represents a risk to the safe and reliable performance of the distribution network.

The key issues[84] that Western Power has identified in the NMP are:

- technical obsolescence of distribution SCADA & Communications assets
  - field devices including controllers, VHF/UHF radios, modems and antennas based on obsolete and unsupported analog electronic components and anticipated withdrawal of commercial telecommunications services
- technical obsolescence of master stations, with obsolete and unsupported computing hardware and software and elevated cyber security risk
- SCADA & Communications systems at all Western Power substations are non-compliant with AEMO communication standards for data quality, data latency and SCADA service reliability
- existing trial Smart Grid network with ageing UIQ operating system that is no longer supported

Western Power advised that the main replacement and upgrade projects planned for AA4 in line with the change to a proactive asset management strategy are as shown in the following table.

[81] NPV values on CAPEX and OPEX related to options, and excludes consideration of revenue or benefits arising from options

[82] Based on industry standard asset lives - 7 years for batteries and enclosures and 10 years for inverters

[83] Refer Western Power assumption for renewable assets - batteries, enclosures and inverters

[84] Western Power, *Network Management Plan 2017/18 - 2027/28*, August 2017, table 242, pp. 206-7

Table 35 Distribution SCADA & Communications - AA4 asset replacement & renewal projects

Project	Equipment scope
Replace Dx SCADA/Comms	Digital backhaul radio
CBD: Replace SCADA/Comms	Remote Terminal Units Modems Data concentrators Optic fibre cables
Replace Operational Country Mobile Voice Network	Digital voice radio
Implement Last Mile Telecomms Expansion	Mesh radio distribution automation

Western Power advised that the SCADA master station and advanced metering support have been estimated on either a top-down approach where similar projects have been undertaken; or a bottom-up estimate where similar projects have not been undertaken and sufficient scope detail is available to enable accurate costing.

The asset replacement and renewal program for SCADA & Communications was commenced during AA3, with the reported actual expenditure suggesting that the scope of work for core infrastructure growth and master station improvements was achieved, whilst there was considerable deferment of expenditure in asset replacement works due to other high priority projects and business transformation initiatives. The main programs deferred were:

- communication NMS equipment replacement by extending the asset life
- radio replacements due to "*delivery resource constraints*"
- upgrading of *Geoview* application at East Perth Control Centre not proceeding as it was superceded by the functionality of a *PowerOn Mobile* application

We have concerns about Western Power deferring expenditure on equipment that is considered important to the safe and efficient operation of the distribution network by extending the asset life, unless this extension has been supported through asset condition analysis and verification that the extension of the asset life did not increase the risk level associated with this asset class.

That noted, we accept that replacement of obsolete equipment is prudent, and that proposed AA4 program is a continuation of that started in AA3, with the expenditure during the AA3 period considered reasonable in the GBA review. We did not have available any detailed estimates for the planned AA4 asset replacement and renewal activities, and assume that the estimating processes used for generating expenditure forecasts for AA3 (see above) that were considered reasonable are similar to those used in forecasting allowances for AA4.

A benchmarking review[85] of 6 electricity distribution utilities highlighted that Western Power currently has higher than average SCADA OPEX costs and typical CAPEX costs measured against cost per circuit kilometre. A participant to the study stated they had "*… made considerable investment in SCADA assets in previous years and currently enjoys both low OPEX and CAPEX spend*" (refer section 13.5.6.3).

[85] GHD, *Investigation into Industry Practices for Managing SCADA and Telecommunications Infrastructure*, August 2017, section 3.2.4, pp. 21-31

We note that Western Power has stated that the asset replacement program will continue with asset replacement works deferred from AA3 that are consistent with the proactive asset strategy, and a $17 M upgrade of the master station to ensure the system remains vendor supported.

Whilst we have been unable to separately assess the estimates in detail, given the benchmarking study found that Western Power was comparable to the industry average CAPEX per circuit kilometre, and the AA4 program is a continuation of the previously approved AA3, we are of the opinion that the proposed AA4 CAPEX allowances are reasonable.

We therefore recommend that the CAPEX allowances proposed by Western Power are accepted.

10.6 Summary

The allowances for direct costs recommended for distribution CAPEX are shown in the following tables.

Table 36 Recommended asset replacement CAPEX ($M real direct costs at 30 June 2017)[86]

Distribution asset replacement	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Cable management	7.5	1.5	1.5	1.5	1.5	1.5	7.5
Conductor management	218.7	35.8	34.7	41.5	46.2	51.8	210.0
Dx Other REPEX	20.5	2.8	5.7	4.9	3.0	4.0	20.5
Protective device management	19.4	2.5	3.9	3.7	3.8	5.6	19.4
Streetlight management	19.4	3.9	3.9	3.9	3.9	3.9	19.4
Switchgear management	18.9	3.9	3.8	3.8	3.8	3.8	18.9
Transformer management	48.3	9.5	9.9	9.6	9.7	9.6	48.3
Meters	137.3	15.4	19.8	23.0	23.6	23.9	105.7
Pole management	525.0	137.2	106.6	99.8	94.8	86.5	525.0
State UG Power Program	124.3	32.5	42.3	27.8	6.9	14.8	124.3
Total	**1,139.4**	**245.1**	**232.1**	**219.4**	**197.1**	**205.4**	**1,099.1**

[86] The recommend CAPEX allowances include our change in unit rate for conductor management (refer section 10.2.2.3) and the 23% reduction in volumes for meter replacement (refer section 10.2.3.5)

Table 37 Recommended regulatory compliance CAPEX ($M real direct costs at 30 June 2017)[87]

Distribution regulatory compliance	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Bushfire management	25.9	2.4	9.1	9.1	2.6	2.6	25.9
Conductor management	7.0	1.4	1.4	1.4	1.4	1.4	7.0
Connection management	35.4	7.6	7.1	7.1	7.1	6.6	35.4
Pole management	40.5	2.8	9.5	9.4	9.3	9.5	40.5
Poletop management	2.3	0.1	0.4	0.6	0.4	0.8	2.3
Power Quality compliance	20.3	4.1	4.1	4.1	4.1	4.1	20.3
Reliability compliance	18.3	4.4	4.4	3.5	3.0	3.0	18.3
Security	0.5	0.1	0.1	0.1	0.1	0.1	0.5
Total	**150.3**	**22.9**	**36.1**	**35.3**	**28.0**	**28.1**	**150.3**

Table 38 Recommended growth CAPEX ($M real direct costs at 30 June 2017)

Distribution growth	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Capacity expansion							
HV distribution driven	65.9	13.2	18.1	12.3	6.4	16.1	65.9
HV fault rating & protection	38.5	13.9	8.2	7.4	7.1	1.9	38.5
O_L transformers	18.0	3.6	3.6	3.6	3.6	3.6	18.0
Transmission driven	34.1	5.6	4.8	5.0	9.5	9.2	34.1
Subtotal	*156.5*	*36.2*	*34.7*	*28.3*	*26.6*	*30.7*	*156.5*
Customer driven							
Connection	48.1	9.6	9.6	9.6	9.6	9.6	48.1
Fully funded line relocation	9.3	-	9.3	-	-	-	9.3
Major capital	100.6	20.1	20.1	20.1	20.1	20.1	100.6
Network extension	261.4	52.3	52.3	52.3	52.3	52.3	261.4
Relocation	28.3	5.7	5.7	5.7	5.7	5.7	28.3
Subdivision	60.4	12.1	12.1	12.1	12.1	12.1	60.4
Subtotal	*508.1*	*99.8*	*109.1*	*99.8*	*99.8*	*99.8*	*508.1*
Gifted assets	400.0	80.0	80.0	80.0	80.0	80.0	400.0
Total	**1,064.6**	**216.0**	**223.8**	**208.1**	**206.4**	**210.5**	**1,064.6**

[87] Western Power Excel model *8.3 - Western Power AA4 capital expenditure and capital contribution model,* worksheet *Capex calcs*

Table 39 Recommended service improvement CAPEX ($M real direct costs at 30 June 2017)[88]

Distribution improvement in service	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Reliability driven							
Dx reliability other	13.2	2.9	7.7	1.5	0.5	0.5	13.2
RD pilot projects	0.5	0.1	0.1	0.1	0.1	0.1	0.5
TRDA	5.5	1.1	1.1	1.1	1.1	1.1	5.5
Subtotal	*19.2*	*4.2*	*8.9*	*2.7*	*1.7*	*1.7*	*19.2*
SCADA & Communications							
Asset replacement	32.2	3.9	5.2	7.6	7.4	8.2	32.2
Core infrastructure growth	0.2	0.2	-	-	-	-	0.2
Corporate	25.1	-	-	-	-	-	-
Master station	17.2	4.2	4.5	4.1	3.0	1.3	17.2
Subtotal	*74.8*	*8.4*	*9.7*	*11.7*	*10.4*	*9.5*	*49.7*
Total	**94.0**	**12.6**	**18.5**	**14.4**	**12.1**	**11.2**	**68.9**

Table 40 Recommended AA4 distribution CAPEX ($M real direct costs at 30 June 2017)

Distribution CAPEX	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Asset replacement	1,139.4	245.1	232.1	219.4	197.1	205.4	1,099.1
Regulatory compliance	150.3	22.9	36.1	35.3	28.0	28.1	150.3
Growth	1,064.6	216.0	223.8	208.1	206.4	210.5	1,064.6
Improvement in Service	94.0	12.6	18.5	14.4	12.1	11.2	68.9
Total	**2,448.3**	**496.5**	**510.4**	**477.2**	**443.6**	**455.2**	**2,382.9**

[88] The recommended service improvement CAPEX disallows the proposed incremental SCADA & Communications allowances associated with the AMI project (refer section 10.2.3.5)

11. Forecast CAPEX - transmission

11.1 Western Power AA4 proposal

Western Power has forecast transmission CAPEX of $947.3 million, in real FY2016/17 terms, which represents 22% of total CAPEX for AA4. Table 41 shows the AA3 approved and actual expenditures, and the proposed forecast AA4 transmission CAPEX.

Table 41 Comparison of AA3 and AA4 transmission CAPEX ($M at 30 June 2017)[89] [90]

Regulatory category	AA3 approved	AA3 actual	AA4 forecast
Growth	1,351.0	564.0	355.8
Asset replacement/renewal	184.1	186.3	296.2
Improvement in service	84.3	60.2	108.4
Compliance	135.6	111.9	186.9
Total	**1,754.8**	**922.5**	**947.3**

Table 42 shows the total proposed forecast transmission CAPEX (including indirect costs and escalation) in AA4 by regulatory category in real FY2016/17 dollars.

Table 42 Total proposed transmission CAPEX for AA4 ($M at 30 June 2017)[91]

Regulatory category	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Growth	53.5	53.7	68.0	95.4	85.2	355.8
Asset replacement/renewal	42.5	70.5	56.9	57.9	68.5	296.2
Improvement in service	14.0	23.6	27.0	24.7	19.2	108.4
Compliance	39.5	40.4	40.5	33.2	33.3	186.9
Total	**149.4**	**188.2**	**192.4**	**211.2**	**206.1**	**947.3**

For AA3, Western Power underspent their approved capital expenditure allocation of $1.75 billion by approximately 47%, and for AA4, Western Power is proposing an increase on AA3 actual expenditure of approximately 3%, due to increases in asset replacement and renewal programs, improvement in service through the replacement of SCADA & communications assets, and compliance programs for substation security and transmission support structures.

Table 43 shows the total proposed forecast transmission CAPEX (direct costs only) in AA4 by regulatory category in real FY2016/17 dollars.

[89] Includes real cost escalation and indirect costs

[90] Western Power Excel model *10.4 - AA4 Regulatory Revenue Model.xlsx*, worksheet *Tx_Inputs* rows 101 to 137

[91] Ibid.

Table 43 Total proposed transmission CAPEX for AA4 ($M direct costs at 30 June 2017)[92]

Regulatory category	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Growth	44.2	44.9	57.4	78.1	69.4	294.1
Asset replacement/renewal	35.1	58.9	48.0	47.4	55.8	245.2
Improvement in service	11.5	19.7	22.8	20.2	15.6	89.9
Compliance	32.6	33.7	34.2	27.2	27.2	155.0
Total	**123.5**	**157.2**	**162.5**	**173.0**	**168.0**	**784.2**

11.2 Asset replacement

Western Power is proposing an increase of $110 million or 59% in asset replacement CAPEX for AA4 compared to the actual expenditure for AA3. With reference to Figure 33, the main contributory factors are the replacement of:

- SVCs
- switchboards
- protection equipment

Western Power is basing the proposed replacement program for AA4 on assessments of:

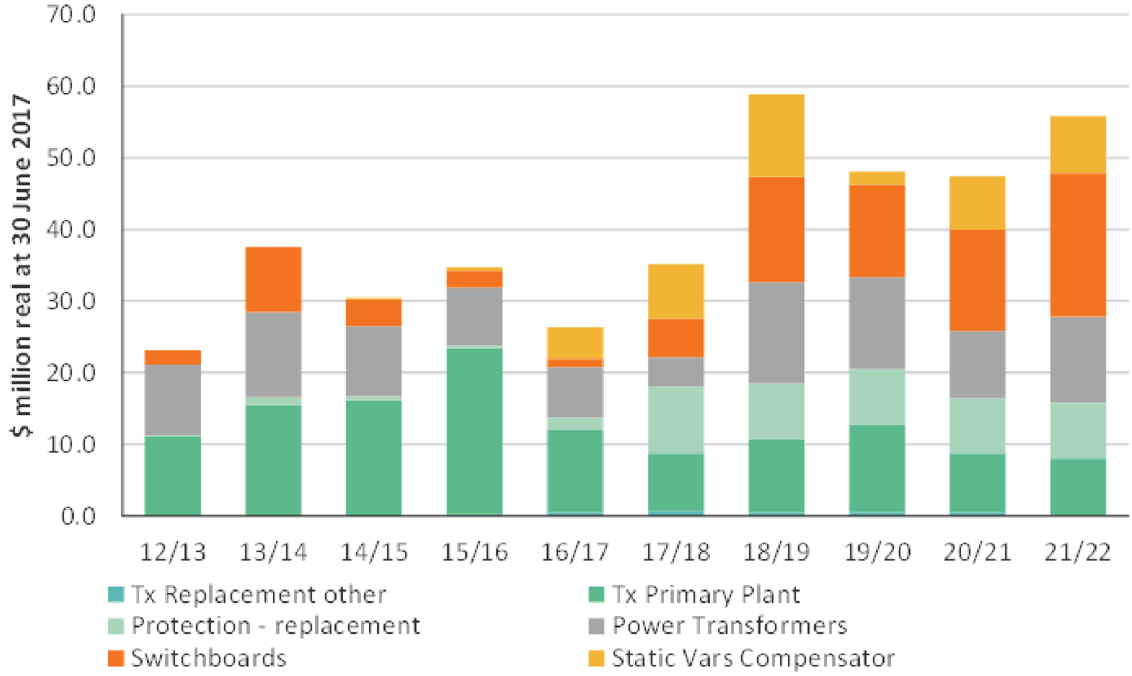
- asset condition
- asset in-service age
- technical obsolescence
- risk

This significant increase in forecast asset replacement CAPEX for AA4 is in part due to some of this work having been deferred during AA3 as a result of major transformer failures at Muja Terminal Station[93], and is offset by a forecast decrease of $208 million in growth-related expenditure.

92 Ibid.

93 Western Power, *Access arrangement information for AA4 period*, EDM #43728581, 2 October 2017, clause 618, p. 165

Figure 33 AA4 forecast replacement CAPEX ($ million at 30 June 2017)[94]



11.2.1 Power transformers

Western Power has 342 in-service, 4 rapid response, 22 strategic spares. The justification for the expenditure is based on service reliability associated with 90 transmission transformers assessed as being in 'bad'' or "poor" condition, with predominant issues associated with high oil moisture content, ageing bushings, type related tap changer performance issues, winding movements due to substandard clamping. 36 of the currently known 90 bad/ poor condition transformers are planned to be addressed, with the plan optimised with the NDP including the replacement of 3, decommissioning of 19 and refurbishment of 14 power transformers. In addition 4 new transformers will be installed.

Western Power plans to mitigate the risks associated with remaining poor/ bad condition transformers using rapid response transformers and spare transformers being deployed as required. In addition, 1 reactive replacements, 2 strategic spares and 1 mobile transformers are included in the plan.

We agree that the overall approach is reasonable with refurbishment being able to resolve some of the issues and deferring full replacement cost which is both an economic solution, allows more timely action to improve the asset and avoids long duration security risks with outages.

Detailed business cases and condition reports supporting the proposed CAPEX of $52.4 million (direct costs only) for power transformers were not available to us at the time of this review.

Given the previous history of deferment of asset replacement during AA3, we have adopted a conservative view that 15% of the proposed replacements could be deferred with appropriate maintenance repairs until AA5. In addition, based on our market data and an assumed scope of work, we would suggest further a 30% reduction in this area as available to Western Power through *"… efficiencies identified during project development and implementation*" as stated in their submission.

[94] Direct costs only

Therefore, we recommend a reduction of approximately 40% on the Western Power proposed expenditure of $52.4 million, resulting in an allowance of $31.95 million.

11.2.2 Primary plant

11.2.2.1 Outdoor switchgear

Western Power has 1,587 outdoor circuit breakers, and a high number of outdoor circuit breakers are beyond their MRL. Some of these assets have make/ type defects leading to Sulphur Hexafluoride (SF_6) gas leaks or incorrect operation. Maintainability of these circuit breakers is made more difficult due to lack of spare parts and minimal manufacturer support.

A total of 53 circuit breakers are defined as in “bad” condition, 91 circuit breakers have make/type defect with maintainability issues, 150 circuit breakers have maintainability issues due to lack of manufacturer support.

We agree with the approach taken by Western Power in monitoring condition through routine inspections and repair/ treat defects prioritised by risk.

We do not have sufficient information available to us for a detailed assessment of the scope and associated costs for outdoor switchgear replacement work planned for AA4. We would expect some efficiencies through business transformation and greater efficiency in delivery and would recommend an allowance of $39.74 million, assuming a 15% efficiency through improved delivery.

11.2.2.2 Static VAr Compensators

Western Power has forecast a total of $36.2 million[95] for replacement of SVCs during AA4.

Transmission reactive plant has been assessed a low risk on safety and a medium risk on reliability and power quality. The Western Power strategy to mitigate against failure of these types of assets is based on condition assessment. For SVCs, these types of assets can potentially have significant impact on network reliability and typically have long lead time for replacement. Therefore, the three SVCs in the Western Power network located at Merredin Terminal Station, West Kalgoorlie Terminal Station and Southern terminal Station are routinely monitored. The investment in replacement of two of these SVCs has been deferred over the last two regulatory periods and the condition of these SVCs is considered to be poor leading to reliability issues.

Western Power has stated that the costs of $23 million for the T0410271 West Kalgoorlie project including two 8 MVAr capacity units[96] are based on “… *market research for new technology, feedback from tendering processes and detailed construction and control philosophy design.*“ Information was not available to us to allow an assessment of these projected costs.

The replacement of the SVC at Merredin Terminal is planned from 2020/21, with a total expenditure during AA4 of $13.2 million. A further $2.8 million is forecast to be spent on this project in 2022/23 during AA5. At the time of our review, there was no scope of work available to us for this project.

Based on market data available to us at the time of this review, and given the minimal project definition available to us, our comparative estimate for these SVC replacements is approximately $14.6 million.

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[95] Direct costs only as at 30 June 2017

[96] Western Power, *Network Development Plan 2016/17 - 2027/28*, June 2017, section 5.4.7.1, p. 54

11.2.3 Switchboards

[redacted]

[redacted]

[redacted] [redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The 3 substations in the CBD Hay Street, Milligan Street and Forest Avenue are interconnected as are a number of the Metro substations around University. This will lead to conflict on any work at these sites where they will be unable to carry out work concurrently, and with the restrictions on outages due to season, and peak demands it is prudent to target some replacement in AA4 while managing the adjacent site issues. Western Power has therefore chosen to replace the following switchboards.

The forecast costs provided for these projects are shown in the following table.

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total			**13**	**67.4**	

[redacted]

[redacted]

[redacted]

[redacted]

11.2.4 Protection

Western Power is proposing a marked increase in replacement rates of protection systems during the AA4 period, justified as necessary to maintain network reliability and stability. Past expenditure on secondary systems is considered to have been low.

In the Access Arrangement Information for AA4, Western Power has justified the investment in protection in AA4 as more crucial given the proposed decrease in primary plant replacement.[97] There are also known performance and obsolescence issues.[98]

Forecast expenditure on protection replacement for the AA4 period is $40 million. The key strategy is assessing condition through routine visual inspections, testing and remote monitoring. Currently, approximately 36% of the protection relays have been in-service beyond their nominal asset life. This is projected to increase to 50% by 30 June 2022 and 61% by 30 June 2027 without proactive replacement.[99] For protection relays, Western Power has assessed a low risk on the reliability of the network and a medium risk with regards safety.

The program for the proposed AA4 relay replacement is shown in Table 46.

Table 46 Relay replacement program for AA4 ($ million at 30 June 2017)[100]

	Proposed volumes for AA4 period						AA4 Cost ($M)
	2017/18	2018/19	2019/20	2020/21	2021/22	Total	
No. of main relays	89	88	88	88	88	441	38.6
Unit rate ($,000)	87.31	88.31	88.31	88.31	88.31		
Other (non-volumetric)	-	-	-	-	-	-	1.7
Total							**40.3**

[97] Western Power, *Access arrangement information for AA4 period*, EDM #43728581, 2 October 2017, clause 83, p. 14

[98] Western Power, *Network Management Plan: Transmission and Distribution Network 2017/18 - 2027/28*, EDM #34159326, section 8.6, table 263, p. 240

[99] Ibid., p. 124

[100] Direct costs only

We understand that Western Power manages replacement of protection systems on a volumetric program basis. The volume of protection equipment represents the number of “main relays” e.g. for a 132 kV circuit with duplicate protection, each end will have two “main relays”. Therefore, the proposed program as shown in Table 46 represents the equivalent of 22 132 kV circuits per year over the 5 years of AA4.

We consider the proposed replacement program to be substantial increase on the previous AA3 forecast expenditure of $10.6 million, particularly given actual expenditure in AA3 was $5.1 million.[101]

Given the historic expenditure in this category, the assessed relative lower risk and that many of the key drivers identified for replacement would have equally applied during AA3 when 52% of the proposed expenditure was deferred, we do not accept that the step change in expenditure has been sufficiently justified.

In the absence of additional supporting evidence, we would expect the projected costs to be closer to the AA3 actual spend although we do accept that the underspending in AA3 would result in an increase in AA4. We recommend an allowance of $20.1 million, which is nominally 50% of the Western Power proposed allowance.

11.3 Compliance

Compliance CAPEX relates to a range of safety, environmental and service compliance obligations for Western Power, and encompasses non-growth investment on the transmission network due to the Technical Rules, environmental protection regulations and electricity industry statutory codes and regulations.

Table 47 shows a comparison of expenditure patterns between AA3 and AA4 for compliance CAPEX on the transmission network.

Table 47 Comparison of AA3 and AA4 compliance CAPEX ($M real at 30 June 2017)[102] [103]

Regulatory category	AA3 approved	AA3 actual	AA4 forecast
Compliance	135.6	111.9	186.9

Table 48 details the total proposed forecast CAPEX (including indirect costs) for the regulatory compliance activities during AA4.

[101] Western Power *5.2 - AA3 Capital Expenditure Report - Variance* Excel model, row 63

[102] Includes real cost escalation and indirect costs

[103] Western Power Excel model *10.4 - AA4 Regulatory Revenue Model.xlsx*, worksheet *Tx_Inputs* rows 101 to 137

Table 48 AA4 total proposed compliance CAPEX ($M real at 30 June 2017)[104]

Transmission regulatory compliance activity	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Poles and towers	15.2	15.0	15.0	13.6	13.6	72.5
Cross arm replacement	1.2	1.1	1.1	1.2	1.2	5.8
Substation security	22.0	15.8	20.2	15.1	13.9	87.0
Transformers	0.5	6.3	4.1	3.0	1.4	15.2
Protection	0.6	2.2	-	-	-	2.8
Cables	-	-	0.1	0.3	3.4	3.7
Total	**39.5**	**40.4**	**40.6**	**33.2**	**33.3**	**186.9**

Table 49 shows the AA4 proposed forecast CAPEX (direct costs only) for regulatory compliance activities.

Table 49 AA4 proposed compliance CAPEX ($M real direct costs at 30 June 2017)[105]

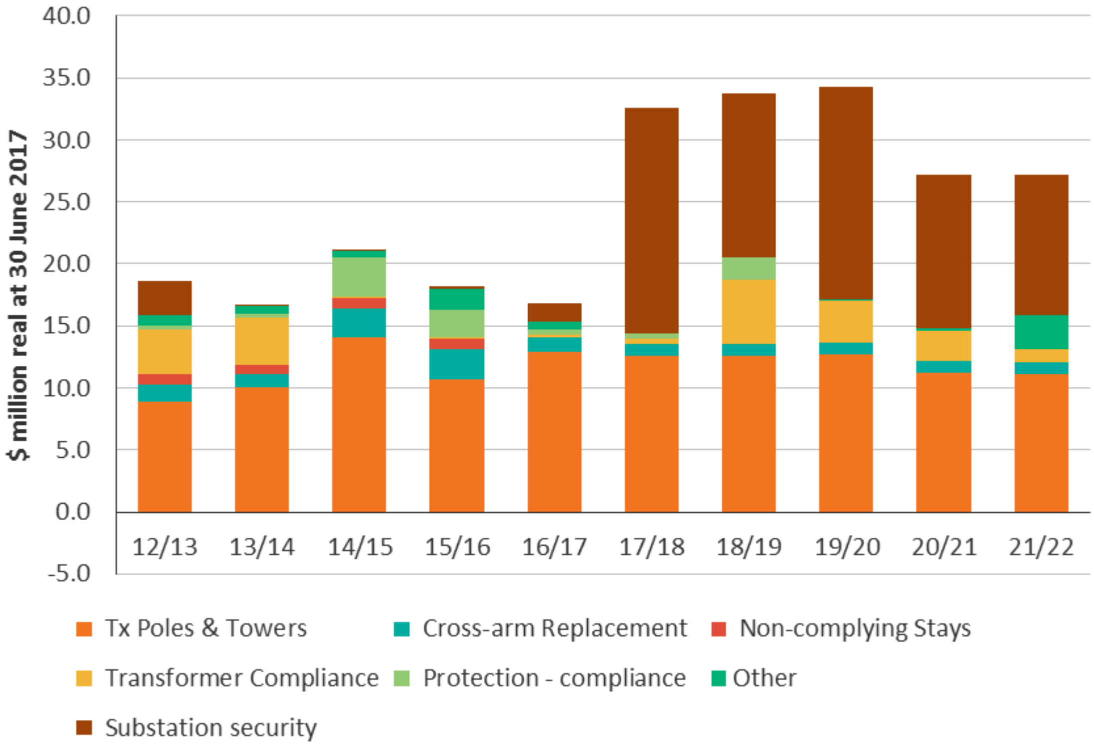
Transmission regulatory compliance activity	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Poles and towers	12.6	12.6	12.7	11.2	11.1	60.0
Cross arm replacement	1.0	0.9	0.9	0.9	0.9	4.8
Substation security	18.2	13.2	17.1	12.4	11.3	72.1
Transformers	0.4	5.2	3.5	2.5	1.1	12.7
Protection	0.5	1.8	-	-	-	2.3
Cables	-	-	0.1	0.2	2.7	3.0
Total	**32.6**	**33.7**	**34.2**	**27.2**	**27.2**	**155.0**

Figure 34 illustrates the compliance CAPEX for AA3 and the AA4 forecast for each of the regulatory activities. The values shown are at 30 June 2017, and represent direct costs only. The two main programs that are contributing to the compliance CAPEX for AA4 are substation security and transmission support structures (poles and towers).

[104] Western Power Appendix *8.3 - Western Power AA4 capital expenditure and capital contribution model.xlsx*, worksheet *Capex calcs,* columns AF to AK

[105] Western Power Appendix *8.3 - Western Power AA4 capital expenditure and capital contribution model.xlsx*, worksheet *Capex calcs,* columns H to M

Figure 34 Forecast compliance CAPEX for AA4 ($ million at 30 June 2017)



11.3.1 Substation security

11.3.1.1 Background

The investment proposed for substation security during AA4 is shown in Table 49 with a substantial increase from that incurred during AA3. The overall expenditure on security dominates the compliance expenditure forecast for AA4.

Western Power regularly assesses the safety risks that may result from unauthorised entry into transmission substation sites, distribution substation sites and enclosures, and the consequent damage to perimeter fencing, theft of property and vandalism at their 154 substations [redacted] This approach by Western Power is consistent with other electricity utilities, and relies on monitoring through routine inspection, carrying out repairs as required and, where third-party access is persistent, enhance the security.

As part of the security review process, in 2016 Western Power undertook a review [redacted] of selected substations, communication facilities and depots in metropolitan and regional areas to assess the vulnerabilities and existing security measures, to identify any specific issues and develop a common approach. [redacted]

[redacted]

- [redacted]
- [redacted]

[106] AECOM, *Physical Security Strategy Stage 1: Security Review*, 03 March 2016

- [redacted]
- [redacted]
- [redacted]

The report notes that Western Power has subsequently developed a draft Security Management Framework.

In addition, the study discussed the potential for the following security incidents due to unauthorised access to Western Power sites:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

It was recommended that Western Power should be aware of the national terrorism threat advisory system, and that they should continue liaising with intelligence and law enforcement agencies to review appropriate security measures.

11.3.1.2 Assessment

The *National Guidelines for Protecting Critical Infrastructure from Terrorism*[107] provides a national and consistent approach for the protection of critical infrastructure from terrorism for businesses and State and Territory governments. These guidelines establish the basic common framework for all States and Territories in Australia for identifying critical infrastructure and assessing risk and its mitigation, response and security considerations.

The National Guidelines do not set any mandatory requirements with regards to timeline for compliance, nor are they prescriptive about the measures to be taken or the assets to be assessed. This is left with the individual States or businesses to assess within their own risk assessment frameworks. The document defines critical infrastructure as *"… those physical facilities, supply chains, information technologies and communications networks which, if destroyed, degraded or rendered unavailable for an extended period, would significantly impact the social or economic wellbeing of the nation or affect Australia's ability to conduct national defence and ensure national security*."[108]

The Western Power substation security review report provides no quantified number of incidents where unauthorised access has occurred or where costs have been incurred, or where there are remote substations which have not been subject to access inside buildings or fences. It focused on the security issues that were identified for the sites selected for the review only. [redacted]

With regards to the critical nature of assets, the Western Power substation security review quoted the WA Office of the Auditor General as stating it identified [redacted]

[107] Published by the Australia-New Zealand Counter-Terrorism Committee, 2015

[108] p. 3

[109] [redacted]

[redacted]

We note that the NMP does not directly address the National Guidelines relating to critical infrastructure, nor does it include any risk assessment of assets, plant, equipment or sites that are classified as critical infrastructure in line with the definition included in the National Guidelines.

We disagree with the broad conclusion of the Western Power substation security review report regarding the prudency of classifying the entire SWIN as critical infrastructure, as we consider this was not the intent of the National Guidelines or the WA Office of the Auditor General, nor do we consider a blanket assessment of criticality is sufficient. For example, a disruption in service due to unauthorised access and criminal damage or terrorist act in a remote substation in the Eastern Goldfields or North Country will likely be a major event for the customers directly affected, but we do not think this would satisfy the test for critical infrastructure of affecting the social or economic well-being of Western Australia, or the nation.

To satisfy the definition for critical infrastructure, we would expect to see specific risk assessments under the NRMT for each substation, and for these to be prioritised in accordance with the WA Office of the Auditor General definition for services that are essential to the State's social and economic well-being.

In the absence of any directive or legislation from the WA Government instructing compliance for all assets within the SWIN to be regarded as critical infrastructure, we do not accept the proposed expenditure of $72.1 million for upgrading substation security during AA4.

[redacted]

[redacted] We note that substation security expenditure during AA3 was relatively minor, with the largest allocation in 2012/13 being approximately $2.5 million (refer Figure 34). Therefore, we recommend an annual allowance of $2.5 million during AA4, totalling $12.5 million.

11.3.2 Transmission support structures

For the asset replacement program for transmission support structures, Western Power has proposed a total of $60 million for AA4.

The transmission support structure population as at 30 June 2016 consisted of:

- 27,620 wood poles
- 6,566 non-wood poles - concrete, steel and gantries
- 6,257 steel towers

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110 Ibid.

111 Ibid.

112 Western Power, *Network Management Plan: Transmission and Distribution Network 2017/18 - 2027/28*, section 5.10, p. 201

- 7,501 cross-arms and cross-beams
- 5,656 stay systems

Key issues[113] identified in the NMP are:

- The MRL of the transmission wood pole population is approximately 62 years, with 2% of the population in-service beyond the MRL. If poles are only replaced upon failure, the over-age population is projected to be 4% by the end of the AA4 period (2021/22) and 7% in by the end of the AA5 period (2026/27).
- Approximately 58% of the wood pole population is Jarrah, which can suffer internal rot that makes accurate condition assessment difficult
- Approximately 1% of the non-wood poles will be in-service beyond their MRL by the end of the AA5 period.
- Approximately 30% of cross-arms and beams are currently operating beyond their MRL (steel cross-arms and beams 50 years, wood 40-48 years)

Western Power has noted that it has a "*… long term plan to upgrade its 66 kV network to 132 kV. Continuing to replace 66 kV poles like-for-like, does not offer optimised whole-of-life-cycle cost for a line section (that can be achieved by a complete section rebuild to upgrade from 66 kV to 132 kV) and possess a key asset management challenge.*"

Based on their experiences in addressing the EnergySafety order for distribution pole rectification during AA3, we understand that Western Power is improving their pole management and predictive failure techniques and therefore we expect that there will be fewer and more targeted pole replacements planned for AA4. The NMP nominates the challenges for the transmission support structures as:

- deteriorating condition due to ageing
- 846 wood poles require replacement and 6,449 wood poles require reinforcement, with approximately 21% of these located in extreme/high risk fire zones or high public safety zones
- 20 steel poles, 42 gantries and 1 concrete pole require replacement
- 219 steel lattice towers require repair due to corrosion
- 275 cross-arms and 651 stay systems to be replaced
- progressively remove wood poles from substations and replace with steel poles
- wash insulators in high pollution and high risk zones

For the AA4 period, the plan proposed by Western Power based on historical pole failure data, backlog of pole treatment requirements, forecast pole treatment requirements and cross-arm asset condition & risk assessment is:

- replace 2,534 wood poles[114] and reinforce a further 8,008 wood poles[115]
- replace existing 94 wood poles in substations with steel poles[116]

[113] Western Power, *Transmission Lines Asset Management Strategy*, EDM# 41008510, October 2017, section 3.2.1, p. 21

[114] Western Power, *Attachment 8.1: AA4 Forecast Capital Expenditure*, 2 October 2017, section 1.2.1.6.1, p. 46

[115] Western Power, *Transmission Lines Asset Management Strategy*, EDM# 41008510, October 2017, p. 82. Asset strategy includes reinforcement of all hardwood poles that have been in-service for at least 25 years of age to reduce unassisted failures

[116] Ibid., p. 6

- replace 829 cross-arms
- wash 19,715 insulators and silicone an additional 11,560 insulators

The residual risk level for transmission support structures as at 30 June 2016 was assessed as an overall medium network risk, with 3 Medium ratings (reliability, fire and physical impact) and 2 Low ratings (shock and environment). This is a lower than for distribution poles that have an assessed high network risk (refer section 10.2.1).

We note that the proposed volume of cross-arm replacements planned for AA4 represents approximately 11% of the total cross-arm population. The AMP highlights that the average unassisted failure rate for a 4-year period to 2015/16 was 7 per year, but which is forecast to increase sharply to 45 per year[117] if only replaced on failure during AA4. Approximately ⅓ of the unassisted failures for the 4-year period to 2015/16 were in extreme and high FRZs.

As the MRL is currently only exceeded by 2% of the wood pole population, we would expect, consistent with standard electricity industry practice, Western Power could potentially allow this percentage to increase during AA4, with an associated reduction in the CAPEX allowance. However, Western Power has noted that 58% of all transmission wood poles are Jarrah, which is a local hardwood timber species grown only in Western Australia, and "*… being the most common hardwood species Jarrah wood poles set the performance pattern for the whole of the wood pole population. These poles often develop an internal rot (carroty rot) that increases the risk of failure and may remain undetected during inspection while other conditions in the pole are duly identified. This therefore presents challenges in accurate condition assessment of these poles.*"[118]

Western Power has noted that with the completion of the work under the EnergySafety order (refer section 10.2.1), the asset focus has been shifted to the management of transmission support structures, particularly as 26% of transmission wood poles require treatment as at 30 June 2016.

We are of the opinion that the scope of work is reasonable, given the condition assessment reported, and in addressing the risks identified; particularly given the age of the pole and cross-arm populations in relation to the MRL for these asset types[119], the associated forecast sharp increases in over-age cross-arm assets if only replaced on failure, and the currently high number of Jarrah poles that are difficult to condition assess due to their failure mode.

Similar to distribution poles (refer section 10.2.1.1), whilst Western Power suggests that the investment is linked to the quality of condition data, and targets assets with historically high likelihood of failure, we would expect that Western Power will not allow safety or the risk profile of the current transmission wood pole population to be compromised should condition assessment recommend replacement or reinforcement in volumes and costs beyond those forecast, particularly given that the current replacement/reinforcement volumes project a potentially higher wood pole unassisted failure rate by the end of AA5.

Based on the Western Power scope of works, our comparative estimate[120] for the scope of work outlined above for AA4 is $51.5 M which varies from the Western Power proposed $60 M by approximately 14%, which is within our nominal ±15% range for reasonableness. Our estimate does not consider any additional

117 Ibid., p. 81

118 Ibid., section 3.2, p. 17

119 62 years for transmission wood poles, 50 years for steel cross-arms & beams, 40-48 years for wood cross-arms

120 Our comparative estimate includes $9,725 for pole replacement, $1,247 for pole reinforcement, $10,143 for new steel pole which are approximately 20% higher than the distribution rates used in section 10.2.1.2

logistic costs, and have assumed typical construction conditions for pole replacement/reinforcement work (similar to assumptions in section 10.2.1.2).

Given the accuracy and limitations of our comparative estimate, we recommend the proposed allowance for AA4 of $60.0 million is accepted.

11.4 Growth

Growth CAPEX typically includes to discrete projects that address issues related to:

- Capacity expansion
  - Midwest
  - Supply
  - Thermal management
  - Voltage
- Customer driven
  - Customer access
  - Line relocations

Table 50 shows a comparison of the expenditure approved and incurred for AA3 and the proposed forecast expenditure for AA4 (including real cost escalation and indirect costs).

Table 50 Comparison of AA3 and AA4 growth CAPEX ($M at 30 June 2017) [121]

Regulatory category	AA3 approved	AA3 actual	AA4 forecast
Capacity expansion	1,053.60	487.63	241.94
Customer driven	297.37	76.40	113.87
Total	**1,350.97**	**564.04**	**355.81**

Table 51 shows the total proposed forecast growth CAPEX (including indirect costs and escalation) during AA4.

Table 51 AA4 total proposed growth CAPEX ($M real at 30 June 2017) [122]

Transmission growth	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Capacity expansion						
Midwest	0.39	0.06	0.04	-	-	0.49
Supply	22.75	24.57	19.35	65.07	49.19	180.94
Thermal management	0.86	0.57	0.45	0.70	9.41	12.00

[121] Western Power Excel model *10.4 - AA Regulatory Revenue Model,* worksheet *Tx_Inputs,* rows 102 to 138

[122] Western Power Excel model *8.3 - Western Power AA4 capital expenditure and capital contribution model,* worksheet *Capex calcs*

Transmission growth	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Voltage	6.67	5.96	25.85	6.60	3.44	48.52
Subtotal	*30.68*	*31.15*	*45.68*	*72.38*	*62.04*	*241.94*
Customer driven						
Customer access	17.11	16.93	16.74	17.26	17.36	85.41
Line relocations	5.70	5.64	5.58	5.75	5.79	28.47
Subtotal	*22.82*	*22.57*	*22.32*	*23.02*	*23.14*	*113.87*
Total	**53.50**	**53.73**	**68.01**	**95.39**	**85.19**	**355.81**

Table 52 shows the proposed forecast growth CAPEX (direct costs only) during AA4.

Table 52 AA4 proposed growth CAPEX ($M real direct costs at 30 June 2017) [123]

Transmission growth	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Capacity expansion						
Midwest	0.33	0.01	0.00	-	-	0.41
Supply	18.80	20.52	16.34	53.31	40.08	149.06
Thermal management	0.71	0.48	0.38	0.57	7.70	9.81
Voltage	5.51	4.98	21.83	5.41	2.80	40.53
Subtotal	*25.38*	*26.02*	*38.59*	*59.29*	*50.55*	*199.81*
Customer driven						
Customer access	14.14	14.14	14.14	14.14	14.14	70.71
Line relocations	4.71	4.71	4.71	4.71	4.71	23.57
Subtotal	*18.86*	*18.86*	*18.86*	*18.86*	*18.86*	*94.28*
Total	**44.21**	**44.88**	**57.44**	**78.15**	**69.41**	**294.09**

There were 17 capacity expansion projects[124] deferred during AA3 (totalling $273.15 million), mostly due to a reduction in peak demand forecasts and diminished growth drivers during the regulatory period 2012/13 to 2016/17. Some of the projects deferred to AA4 included:

- Construction of a new CBD substation
- Hay/Milligan Street supply reinforcement
- Installation of reactive support at Katanning substation
- Installation of 3rd transformer at Rangeway substation

[123] Western Power Excel model *8.3 - Western Power AA4 capital expenditure and capital contribution model,* worksheet *Capex calcs*

[124] Western Power Excel model *5.2 - AA3 Capital Expenditure Report - Variance*

Due to the flat forecast in AA4 for network peak demand, any growth CAPEX during AA4 is focused on those areas where there is expected to be a localised steady growth in demand such as Mandurah, Rockingham, Bunbury, Busselton and the Eastern Goldfields.

11.4.1 Supply

The supply component of capacity expansion includes growth-driven reinforcement of substations.

11.4.1.1 T0362344 CBD new substation

This project relates to a new 132 kV substation at Bennett Street to address multiple asset condition issues in the existing Wellington Street and Forrest Avenue 66 kV substations.

There are issues reported in the Forrest Avenue substation of multiple transformer and switchboard asset condition problems, and a number of circuit breaker and other plant assets at Wellington Street substation that are degraded and requiring replacement. In addition, the 66 kV cables that supply both substations have been identified as having asset condition issues.[125] The transmission CAPEX forecast includes a total allowance of $62.2 million, with annual expenditure ramping up significantly from 2019/20.

The Western Power AA4 capital expenditure report[126] highlights that the new substation is expected to be in service by 2024/25 with Forrest Avenue and Wellington Street substations decommissioned by 2027/28. However, a footnote to the project description states that "…*Western Power has reviewed the CBD substation project in light of the updated 2017/18 load forecast and has determined the outcomes of addressing the aged asset conditions of Forrest Ave, Wellington St and East Perth 66kV substations can be addressed by transferring the load to the existing Hay and Joel Terrace substations with additional distribution feeders and the proposed new CBD substation project can be deferred outside the current 10-year investment plan. While there will be a reduction in transmission works associated with this deferment there will still be a requirement to invest in additional distribution works. The revised program will be included as part of Western Power's response to the draft decision.*"[127]

As part of our review of this project, Western Power advised that *"… this investment appears in the AA4 Forecast, and is at pre business case stage. As part of the Regulatory Test for the new Hay to Milligan Street 132 kV cable it has been identified that this substation can be deferred. This is outlined in footnote 23 on page 26 of the AA4 Capital Expenditure Report. Planning is underway to understand the impact of this deferral and this will be included in our response to the Draft Decision."*[128]

We note that in summarising the key AA transmission capacity expansion projects, Western Power stated that "*… a recent review of the 2017/19 load growth forecast suggest installation of the new CBD substation may be deferred to the AA5 period. However, it is likely some additional transmission and/or distribution networks will be required in lieu of the new substation during the AA4 period. Therefore, we have retained the CBD substation amount in the forecast amount in this proposal, and will revisit in our response to the draft decision by which time we will have more information.*"[129] This project was previously included in the AA3 CAPEX program but deferred due to a reduction in the peak demand forecast, and "diminished" growth drivers for a new substation.

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[125] Western Power, *Network Development Plan*, June 2017, section 5.13.7.2, p. 184

[126] Western Power, *Attachment 8.1: AA4 Forecast Capital Expenditure*, 2 October 2017

[127] Ibid., p. 26

[128] Email of 25 October 2017

[129] Western Power, *Attachment 8.1: AA4 Forecast Capital Expenditure*, 2 October 2017, Footnote 22 to Table 1.7, p. 24

Given the highly contingent nature of this project, we do not agree that it should have been included in the AA4 CAPEX forecast. The advice in the NDP and the footnote suggesting that the projected expenditure cost should be retained as a contingency against possible network augmentation is evidence that Western Power has not as yet developed an optimal solution to the asset condition problems identified at Forrest Avenue and Wellington Street substations. We do not accept it as reasonable to include the full substation costing as the contingent sum for possible unidentified distribution/transmission works, nor do we accept that Western Power should include a project deferred from AA3 on the AA4 program when the apparent construction difficulties for a new CBD substation in a highly developed area have not been fully investigated.[130] We also note that the switchboard at Forrest Avenue substation has been included in the switchboard replacement program (refer section 11.2.3 and Table 44). We believe that Western Power should have proposed a separate contingent sum for any additional distribution/transmission works, at a value more appropriate for the potential works rather than rolling over the CBD substation estimate.

We therefore do not accept the proposed $62.2 million CAPEX allowance, and recommend it is excluded from the AA4 CAPEX forecast.

11.4.1.2 T0362480 CBD Hay/Milligan supply reinforcement

Hay Street (HAY) and Milligan Street (MIL) substations are 132/11 kV substations supplying customers in the inner Perth CBD area. HAY is supplied via two 132 kV circuits from East Perth (EP) Terminal Station, whilst MIL is fed from Northern Terminal Station. The EP-HAY feeders are 39-year old oil-filled cables that in poor condition with increasing number of oil leaks. These cables are considered a risk to the security of supply to the CBD area, with a higher likelihood of failure and pose an environmental risk of oil contamination.[131]

Both Hay and Milligan Street substations have been designed to meet N-2 security criterion under the Western Power CBD planning criteria. Under an N-2 event, the loss of both 132 kV feeders at either Hay or Milligan Street substation during peak load currently cannot be mitigated due to inadequate distribution transfer capacity. The NDP highlights that under N-2, there is an existing substation capacity shortfall of approximately 4 MVA.[132]

Western Power has investigated a number of potential augmentations, including the construction of a new substation, and alternate substation connections between Milligan Street - James Street substations and Milligan Street - Cook Street substations. From the business case, the preferred option was the construction of the Hay Street - Milligan Street 132 kV underground cable feeder. The NDP noted the benefit of this option is it will "*… increase the maximum supportable demand in the CBD under N-2 conditions*".[133] The total estimated cost was $32.58 million.

A technical review[134] of the regulatory test application for this project identified asset condition replacement as an issue raised in the Western Power Options Paper[135] including the EP-HAY 132 kV cables. In this report, GBA also identified:

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[130] Western Power, *Attachment 8.1: AA4 Forecast Capital Expenditure*, 2 October 2017, clause 149, p. 26

[131] Western Power, *Network Development Plan 2016/17 - 2027/28*, section 5.13.5.1, p. 176

[132] Ibid., section 5.13.5.1, p. 175

[133] Western Power, *Network Development Plan 2016/17 - 2027/28*, section 5.13.7, table 66, p. 180

[134] Geoff Brown & Associates, *Technical Review of Hay St - Milligan St Cable Regulatory Test Application*, 17 November 2017

[135] Western Power, *Major Augmentation Proposal - Options Paper - Perth CBD: Hay/Milligan Supply Reinforcement Investment*, EDM# 42901215, 4 August 2017

- clause 2.5.3(b) of the Western Power Technical Rules states "*…following any outage within a sub-network to which the Perth criterion*[136] *applies … and irrespective of whether any single transmission element outage is planned or unplanned, there must be sufficient power transfer capacity in the transmission system to maintain supply to all consumers within the Perth CBD without the need to reschedule generation*"
- installation of an interconnecting 132 kV cable between HAY and MIL provides three incoming circuits to each substation, satisfying the N-2 requirement
- preferred option of HAY-MIL 132 kV cable reduces maintenance costs by more than any of the other proposed options
- increases the resilience of transmission network as HAY and MIL substations can then be supplied from either East Perth or Northern terminal stations
- concluded that HAY-MIL 132 kV cable option maximised net benefits and recommended ERA determine the project satisfies the requirements of the Regulatory Test

We note the technical review and ERA final determination on the regulatory application included some concerns regarding the appropriateness of the 2000 mm^2 cable size nominated by Western Power. The technical review speculated on possible loads on the cable and each substation, based on normal operating conditions and no increase in maximum load over a 30-year forecast period, and suggested that the proposed cable size may be "excessive". However, the review also noted that the cable "*… forms part of a 132 kV interconnection between the East Perth and Northern terminal stations and could potentially be required to carry a high load should an unlikely impact contingency arise that the network is not designed to withstand*".[137] GBA concluded that whilst any sizing issues will affect the cost of the preferred alternative, it did not change their assessment of the regulatory test alternatives rankings or qualify their recommendation that the project satisfied regulatory test requirements.

We acknowledge the concerns raised by GBA regarding the cable size, and that their assessment of an appropriate cable size was limited by Western Power not providing information to justify their projection of potential network contingencies requiring a minimum cable rating[138] of 175 MVA. We also note GBA suggested that it would be prudent to consider the possibility of current demand forecasts being conservative and that there could potentially be increases in demand within the lifetime of the assets. Whilst we agree that the lack of verification of the possible network contingency may potentially compromise the efficient sizing of the cable, we are of the opinion that the cost difference between a 1600 mm^2 cable and a 2000 mm^2 cable is only approximately 8%, and that it would be more appropriate for us to base our comparative estimate on the larger cable for the purposes of the AA4 CAPEX review. The project has been recommended to proceed, and the post-AA4 review of CAPEX will be better placed to appraise if the cable is over-sized or not for the purposes of recommending the amount to be added to the RAB.

We have therefore generated a comparative estimate for the nominated scope of works based on 2000 mm^2 cables, and excluding consideration of any site-specific requirements for connection of the 132 kV feeder at the two substations or other cost factors such as traffic control, we have calculated a comparative class 4

[136] N-2 planning criterion where there is no loss of load for two credible contingency events

[137] section 3.4.2, p. 9

[138] Western Power advised GBA that 1600 mm^2 cable has an installed rating of 166 MVA and 2000 mm^2 cable 194 MVA

estimate[139] of $30.68 million[140], which is within 6% variance from the Western Power estimate and within our nominal ±15% variance range for reasonableness. As a result, we consider the Western Power estimate as reasonable.

The sequencing of program stages in the Gate 3 Planning Estimate[141] suggests that the construction has commenced and is expected to be finished by March 2019. This is reflected in the CAPEX forecast for this project.

We recommend the proposed $23.8 million direct cost allowance for this project be included in the AA4 growth CAPEX forecast.

11.4.1.3 Kemerton Terminal 3rd transformer

In response to our request for a business case for this project, Western Power advised that "*… this investment is in early stages of planning and is in the AA4 Forecast with planning works commencing from 2018/19.*"[142] For the scope of works, Western Power referred to the CAPEX appendix to the AAI and the NDP for a project summary.

This summary stated that part of the southern and south-west networks in the Bunbury load areas is at risk of thermal overloads should credible single contingency events occur. Previously, these events were mitigated by the dispatch of the Muja A/B generators; however, these generators are planned to be retired by mid-to-late 2018 and Western Power has consequently investigated a network augmentation plan to mitigate the network security risks, together with the existing and emerging asset condition issues within the area.

As part of this broad long-term strategy, Western Power is proposing to address forecast thermal issues for existing transformers at Kemerton Terminal Station by installing a new 330 kV bay and 330/132 kV 490 MVA power transformer by summer 2021/22.

Based on this high-level description of the assets to be included in this project, we have generated a comparative class 4 estimate of $10.61 million[143] compared to the Western Power proposed $12 million (in real FY2017 terms). This is a variance of approximately 12%, which is within our nominal range of ±15% for reasonableness.

We recommend that the proposed CAPEX allowance of $12 million direct cost be included in the AA4 CAPEX forecast.

11.4.1.4 Substation decommissioning

During AA4, Western Power has proposed the eight (8) substations to be de-commissioned as shown in Table 53 and Table 54.

[139] A Class 4 estimate as classified in the AACE International *Recommended Practice No. 17R-97 Cost Estimating Classification System* is based on 1% to 15% project definition and has an expected accuracy range of ±30%. Class 4 estimates are used for feasibility and concept studies.

[140] Our comparative estimate includes three 2.5 km 132 kV 2000 mm^2 cables and a 132 kV GIS bay c/w CB

[141] Western Power, *Gate 3 Planning Estimate: Project Number T0362480 Hay/Milligan Supply Reinforcement*, EDM# 40497823, 24 January 2017, p. 3

[142] Email of 24 October 2017 - Western Power response to RFI GHD06

[143] Our comparative estimate includes an additional 330 kV feeder bay c/w CB, and a 330/132 kV 490 MVA with a transformer bay c/w CB on the primary and secondary sides at Kemerton Terminal Station

Table 53 AA4 proposed SS decommission CAPEX ($M real direct costs at 30 June 2017)[144]

Substation	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Mundaring Weir	0.04	0.69	0.18	-	-	0.91
Nedlands	0.02	0.35	-	-	-	0.36
Herdsman Parade	0.98	0.03	0.03	-	-	1.04
University	1.51	0.01	-	-	-	1.51
British Petroleum	0.02	-	-	-	-	0.02
Collie	-	-	-	-	0.13	0.13
Durlacher Street	-	0.05	0.51	2.39	0.31	3.26
Coolup	0.10	0.30	3.57	0.99	-	4.96
Total	**2.66**	**1.42**	**4.29**	**3.39**	**0.43**	**12.19**

Table 54 Proposed substations decommissioned during AA4 ($M real direct costs at 30 Jun 2017)

Project no.	Substation	Related project no.	Related project/details	AA4 Total
C1057216	Mundaring Weir	-	Retirement of aged substation, with load transferred to Sawyer Valley SS	0.91
T0180161	Nedlands[145]	-	Partial decommission by 2018/19	0.36
T0380537	Herdsman Parade	T0348702	Decommission as part of construction of new Shenton Park 132/11 kV SS	1.04
T0383976	University	T0367820 T0368532 T0342732	Retirement of aged 66 kV University substation as part of construction of new Medical Centre 132/66/11 kV SS	1.51
T0389229	British Petroleum	T0389229	Load transferred to Mason Road substation 2015/16, with retirement of aged substation by 2017/18	0.02
T0399302	Collie	-	Load to be transferred from Collie substation, with decommission by 2023/24	0.13
T0416418	Durlacher Street	N0375265 T0376054	Load transferred to Rangeway SS by 2018/19, with decommission by 2021/22; related network reinforcement at Geraldton by 2018/19 and installation of third 132/11 kV transformer at Rangeway SS by 2017/18	3.26
T0416509	Coolup	N0391925	Load to be transferred to Wagerup SS, with decommission by 2020/21; related feeder reconfiguration by mid-2019	4.96
Total				**12.19**

[144] Western Power Excel model *8.3 - Western Power AA4 capital expenditure and capital contribution model,* worksheet *Capex calcs*

[145] *Network Development Plan 2016/17 to 2027/28* p. 199 notes that Nedlands distribution feeder to be upgraded to 11 kV and entire load shifted to neighbouring Amherst, Cottesloe and Edmund St substations by summer 2018/19

In their review of AA3 capital expenditure projects[146], Geoff Brown & Associates (GBA) assessed the accounting treatment of substation commissioning costs and compliance against the provisions of:

- Australian Accounting Standard AASB 116
- Section 6.49 of the Access Code

Clause 16 of AASB 116 states that for elements of cost:

> *The cost of an item of property, plant and equipment comprises:*
>
> *(a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates;*
>
> *(b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management; and*
>
> *(c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.*

With regards to the costs that are to be included in the RAB, the Access Code states:

> *6.49 Subject to section 6.50, the capital base for a covered network must not include any amount in respect of forecast new facilities investment.*
>
> *6.50 For the start of each access arrangement period, the capital base for a covered network may include forecast new facilities investment which:*
>
> *(a) has not yet occurred but is forecast to occur before the access arrangement start date; and*
>
> *(b) at the time of inclusion is reasonably expected to meet the new facilities investment test when made.*
>
> *6.51 For the purposes of section 6.4(a)(i) and subject to section 6.49, the forward-looking and efficient costs of providing covered services may include costs in relation to forecast new facilities investment for the access arrangement period which is reasonably expected to meet the new facilities investment test when the forecast new facilities investment is forecast to be made.*

GBA concluded that "*… while we have no view on the correct accounting treatment of decommissioning costs where a site is no longer required, we do not think that decommissioning provisions meet NFIT requirements for inclusion in the RAB. In our view, this treatment is not permitted by the Code …*"[147]

That is, GBA considered that an asset that is removed without being replaced provides no ongoing economic benefits to Western Power, and therefore considers there is doubt about the appropriateness of capitalising the decommissioning costs.

As an example, for project T0383976 regarding the decommissioning of University substation, GBA noted that the original business case treated the decommissioning costs as non-recurring OPEX and that this was

[146] Geoff Brown & Associates, *Review of Western Power's Capital Expenditure during AA3 (2012-2017)*, 20 Dec 2017, section 3.1.1.5, pp. 14-15

[147] Ibid., p. 15

subsequently changed to capitalised costs as part of the AA4 submission. They noted that *"… it is not clear to us that Western Power should be capitalising decommissioning costs on a site* [that] *it no longer requires."* [148]

GBA did not recommend any particular treatment of these costs, leaving it to the discretion of the ERA.

For the decommissioning costs shown in Table 54, we consider that with the exception of project T0180161 (partial decommission of Nedlands substation), the remaining CAPEX totalling $11.83 M relates to the decommissioning of substations that are no longer required.

To be consistent with the AA3 capital expenditure review, we have included the forecast CAPEX allocations for these decommissioning projects in our recommended alternate AA4 CAPEX forecast, subject to a decision by the ERA regarding the appropriate treatment of these forecast decommissioning costs.

11.4.1.5 Black Flag Substation 3rd transformer

With increased mining activity in the Eastern Goldfields area, there is a forecast substation capacity shortfall of 9.73 MVA at Black Flag substation by the end of 2021/22. Planning for a third transformer is in the early stages, with construction work planned from 2019/20. The existing substation capacity is 31.27 MVA. The proposed CAPEX allowance is $5.6 million.

We have generated a comparative class 4 estimate of $3.6 million [149] which does not include any consideration of remote work, or the transport costs for a 132/33 kV power transformer to the substation. From the spatial information available, there is sufficient spare space at the substation for the additional transformer.

Whilst there is a variance of 35% for our comparative estimate, which is outside of our first pass nominal range of ±15% for a test of reasonableness, we are satisfied that the additional logistical costs would be likely contributing factor to the $2 million difference.

We therefore recommend the proposed $5.6 million allowance is accepted.

11.4.2 Thermal management

Thermal management projects are intended to overcome thermal limitations on transmission and sub-transmission lines.

11.4.2.1 NBT - Install Line Reactors

The Neerabup Terminal (NBT) load area covers the northern most part of the Perth Metropolitan region, from Padbury and West Swan in the south to Yanchep in the north and Muchea in the east. The peak demand growth is expected to be flat until 2022, with a period of low load growth to approximately 400 MW by 2028.

There are currently thermal overloads on multiple 132 kV circuits [150] between Mullaloo and Pinjar:

- Mullaloo to Joondalup
- Joondalup to Wanneroo
- Clarkson to Wanneroo
- Clarkson to Yanchep

[148] Ibid., section 3.1.3.2, p. 18

[149] Based on 132/33 kV 35 MVA transformer and additional 132 kV and 33 kV transformer bays

[150] Western Power, *Network Development Plan 2016/17 - 2027/28*, June 2017, section 5.16.5.1, p. 214

- Pinjar to Yanchep

Following an investigation of potential options, including 132 kV network reinforcement and smart protection inter-trip schemes, Western Power decided that the preferred option is the installation of a series of line reactors across multiple 132 kV circuits in the NBT load area by 2022/23. The CAPEX allowance proposed by Western Power for AA4 totals $7.7 million, with $6.9 million planned for 2021/22.[151] We note that the *"… number of reactors required will … depend on new customer and generator connections.*"[152]

In response[153] to our information request, Western Power advised that this project was in the initiation phase, or pre-business case. As a result, the level of project definition was minimal, and no further information was available regarding the proposed number and rating of the 132 kV line reactors.

Our comparative estimate of $6.09 million was based on an assumption of a 132 kV 40 MVAr line reactor installed on each of the five circuits identified in the NDP. This estimate has a variance of approximately 21% from the Western Power proposed AA4 allowance, which is outside our first pass nominal range of ±15% for reasonableness.

Given that this project is planned for the end of the AA4 period, and has uncertainties regarding the number and rating of line reactors that will be required, we are of the opinion that Western Power has likely been conservative in its allowance included in the AA4 proposal. Our comparative estimate does not include consideration of network planning. Our estimate is comparable (with a variance of approximately 12%) of the planned expenditure forecast for 2021/22 ($6.9 million), which we assume is related to the installation of the line reactors. Therefore, whilst we acknowledge the variance between our comparative estimate and the Western Power proposed allocation is outside the range for our nominal test for reasonableness, we are of the opinion that the uncertainty in project scope and our estimate excluding network planning costs would be likely contributing factors to the $1.6 million difference.

As a result, we recommend the CAPEX allowance of $7.7 million (direct costs only) proposed by Western Power is accepted for the AA4 period.

11.4.3 Voltage

Voltage-related projects are designed to maintain adequate transient and voltage margins to maintain network security after network system disturbances.

11.4.3.1 T0357957 PIC-BSN construct new 132 kV line

The proposed CAPEX for AA4 is $19.2 million (direct costs only), with the bulk of the expenditure planned for 2019/20.

This augmentation project was previously proposed for AA3, but was deferred to AA4 due to *"… following completion of preliminary investigative works, the decision was taken to defer the project to ensure prudent timing of expenditure.*"[154]

As mentioned in the previous review for the AA3 period, this "*… second Picton-Busselton 132 kV line was planned to maintain the reliability and security of supply to the Busselton and Margaret River regions since,*

[151] Western Power, Excel model *8.3 - Western Power capital expenditure and capital contribution model*, worksheet *Capex calcs,* cell M84

[152] Western Power, *Attachment 8.1: AA4 Forecast Capital Expenditure*, 2 October 2017, clause 175, p. 29

[153] Response to our RFI GHD08 in email dated 13 November 2017

[154] Western Power, *Attachment 5.2: AA3 Capital Expenditure Report - Variance*

in the absence of a second 132 kV line, it was forecast that the loss of the existing Picton-Busselton 132 kV line would create an under-voltage condition at times of peak demand."[155] At the time of this AA3 review report, alternative solutions were investigated, including reactive power compensation, to defer the requirement for a second line but a 2007 load trend report indicated high rates of peak demand growth in the Busselton and Margaret River regions. Western Power suggested that the most cost-effective solution at that time was the installation of a 132 kV 40 MVAr shunt capacitor bank at Busselton, which could defer any need for augmentation to 2019/20.[156] The 2012 AA3 review concluded that based on a review of projected demand in the Busselton and Margaret River areas, the second PIC-BSN 132 kV line was unlikely to be the most cost effective solution.

The NDP notes that the transmission network south of Picton has exceeded its capacity where a number of unacceptable voltage conditions exist[157] following a loss of the Kemerton-Pinjarra-Picton-Busselton 132 kV circuit. This line is located in a high bushfire risk area and has tripped 11 times in the past 5 years due to bushfires. It also notes that the installation of capacitor banks at Bussleton (completed during AA3 at cost of $3.46 million)[158] provided some relief of the voltage limitations, although the arrangement is not sufficient to ensure reliable supply or any significant increase in demand. The NDP summarises the review of the Bunbury load area by stating that *"… there are no current replacement plans within the study period due to current asset condition knowledge. However, poor asset conditions are often age related and therefore Western Power continues to monitor the condition of the* [following] *assets. A number of wood pole 66 kV transmission line assets exist within the Bunbury load area that are either approaching or already exceeded their mean replacement lives.*

- *KEN-MRR 82 - 61 years*
- *PIC-MRR 81 - 61 years*
- *PIC-PNJ/BSN 81 - 58 years*"[159]

The augmentation options discussed in the NDP include the conversion of an existing 66 kV line between Picton and Busselton to 132 kV[160], but not the construction of a new line. The forecast substation shortfall at Busselton is projected to increase from 5.53 MVA in 2021/22 to 13.36 MVA in 2027/2. A project currently underway involves the installation of a new 132/22 kV transformer at Busselton, and the two 66/22 kV transformers at the substation are sufficient to supply the forecast peak in the event of the loss of one of the 132/22 kV transformers.

The original justification for a second PIC-BSN 132 kV line was based on growth in demand that has not occurred, and there is insufficient evidence provided to suggest that the increase in demand projected in 2007 is likely to occur. The deferment of this project from AA2 to AA3 was in part based on the installation of a capacitor bank at Busselton substation to address the voltage conditions in the region. The project has again been proposed for AA4, with the primary drivers being to address both moderate projected growth in the Bunbury load region, and ageing 66 kV assets.

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155 Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, 27 March 2012, Appendix A.8.1, p. A22

156 Ibid., p. A23

157 Western Power, *Network Development Plan*, June 2017, section 5.7.5.1, p. 94

158 Geoff Brown & Associates, *Review of Western Power's Actual Capital Expenditure during AA3*, November 2017, p. 8

159 Western Power, *Network Development Plan*, June 2017, section 5.7.5.1, p. 95

160 Ibid., p. 106

We do not accept that the justification included in the AA4 forecast capital expenditure is sufficient for this project to be included in the current portfolio. We invite Western Power to provide additional information to support this project, particularly as it relates to the asset condition assessment of the existing PIC-PNJ/BSN 66 kV line and other 66 kV assets, and any network security issues relating to the Picton South area due to a bushfire contingency.

We therefore do not accept the proposed $19.2 million CAPEX allowance, and recommend it is excluded from the AA4 CAPEX forecast.

11.4.4 Customer driven

Customer driven expenditure is related to all CAPEX required to augment the transmission network where customers intend to connect facilities and equipment, or generation at a new connection point. This CAPEX is driven entirely by customer requirements, and therefore any forecast must consider expected economic conditions or market trends.

For AA4, Western Power has proposed annual allocations (direct costs only) of $14.1 million for customer access and $4.7 million for line relocations, totalling $70.7 million for customer access and $23.6 million for line relocations.[161] In the AAI, Western Power notes that, due to the uncertainty and difficulty in forecasting accurately, the AA4 allocations are based on an estimate of the proportion of customer lines installed during AA3 to forecast the customer driven transmission line growth for AA4.

Western Power noted that AA3 customer driven CAPEX expenditure was lower than forecast, due to a slowing of demand growth and weakened economic activity resulting in less investment in capacity expansion and customer driven work.

Figure 35 shows a comparison between the actual expenditure during AA3 and the forecast AA4 allocations. The negative Customer Access value was a one-off transfer of approximately $22 million from the customer driven CAPEX category to the capacity expansion CAPEX category (MWEP) on completion of the Three Springs Terminal Station.

[161] Western Power Excel model *8.3 - Western Power AA4 capital expenditure and capital contribution model*, worksheet *Capex calcs*, rows 99 and 100

Figure 35 AA3 actual and AA4 forecast customer driven CAPEX ($M direct costs at 30 Jun 2017)[162]

From our analysis, the annual allowances in the AA4 forecast approximate to the average annual values of AA3 actual expenditure (excluding the Three Springs Terminal Station expenditure transfer).

The capital contribution rates for the AA4 forecasts are:

- Customer Access - 42%
- Line Relocations - 100%

Table 55 shows the AA4 forecast allowances for customer driven CAPEX and the associated forecast capital contributions.

Table 55 AA4 forecast customer driven CAPEX ($M direct costs at 30 June 2017)

Customer driven	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Customer access	14.1	14.1	14.1	14.1	14.1	70.7
Line relocation	4.7	4.7	4.7	4.7	4.7	23.6
Subtotal	*18.9*	*18.9*	*18.9*	*18.9*	*18.9*	*94.3*
Contributions - customer access	5.9	5.9	5.9	5.9	5.9	29.7
Contributions - line relocation	4.7	4.7	4.7	4.7	4.7	23.6
Subtotal - contributions	*10.7*	*10.7*	*10.7*	*10.7*	*10.7*	*53.3*
Customer driven less contributions	**8.2**	**8.2**	**8.2**	**8.2**	**8.2**	**41.0**

[162] Western Power, *8.1 - AA4 Forecast Capital Expenditure Report*, 2 October 2017, Figure 1.10, p. 31

Customer driven	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Capital contribution as % of total	**57%**	**57%**	**57%**	**57%**	**57%**	**57%**

Given that this CAPEX category is dependent upon economic and market conditions, we consider that it was reasonable for Western Power to use the average of actual expenditure during AA3 as the annual forecast allowances during AA4, particularly as there is no projected growth in demand as was the case at the end of AA3, and that prevailing market conditions are expected to continue in Western Australia.

Table 55 shows that the capital contributions offset for the AA4 period is forecast to be 57% of the gross total customer driven CAPEX. Western Power stated in the AAI that "*… while we access actual capital contributions on a case-by-case basis, these forecasting assumptions reflect the AA3 average recovery rate for capital contributions from transmission customers.*"[163] We confirmed that the applying the assumptions discussed previously in this section for capital contribution rates for AA4 to the actual AA3 customer driven CAPEX expenditure generated capital contributions that constituted 57% of the aggregated AA3 customer driven CAPEX.[164]

Given that forecasting customer driven expenditure is difficult since it is a reactive rather than proactive cost category, and the capital contribution assumptions are consistent with AA3 average recovery rate, we recommend that the customer driven allowances proposed by Western Power for the AA4 period are accepted - $14.1 million per year for customer access and an annual allowance of $4.7 million for line relocations.

11.5 Improvement in service

Table 56 shows a comparison of the expenditure approved and incurred for AA3 and the proposed forecast expenditure for AA4 (including real cost escalation and indirect costs).

Table 56 Comparison of AA3 and AA4 service improvement CAPEX ($M real at 30 June 2017)[165]

Regulatory category	AA3 approved	AA3 actual	AA4 forecast
Reliability driven	-	1.78	-
SCADA & Communications	84.27	58.43	108.42
Total	**84.27**	**60.21**	**108.42**

Table 57 shows the total proposed forecast service improvement CAPEX (including indirect costs and escalation) during AA4.

[163] Western Power, *Access arrangement information*, 2 October 2017, section 8.4.3, clause 715, p. 182

[164] GHD, Excel model *AA4 Transmission customer driven & capital contribution CAPEX*, worksheet *Tx Customer driven*

[165] Western Power Excel model *10.4 - AA Regulatory Revenue Model,* worksheet *Tx_Inputs,* rows 102 to 138

Table 57 AA4 total proposed service improvement CAPEX ($M real at 30 June 2017)[166]

Regulatory category	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Reliability driven	-	-	-	-	-	0.00
SCADA & Communications	13.97	23.63	26.99	24.68	19.15	108.42
Total	**13.97**	**23.63**	**26.99**	**24.68**	**19.15**	**108.42**

Table 58 shows the proposed forecast service improvement CAPEX (direct costs only) during AA4.

Table 58 AA4 proposed service improvement CAPEX ($M real direct costs at 30 June 2017)[167]

Regulatory category	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Reliability driven	-	-	-	-	-	0.00
SCADA & Communications						
Asset replacement - obsolete equipment & pilot cables	8.19	10.79	10.53	11.08	12.09	52.68
Compliance	0.35	2.00	4.10	3.55	3.02	13.02
Corporate - new control centre & depot modernisation	1.83	3.14	3.13	0.97	0.37	9.44
Master station	1.17	3.73	4.94	4.54	0.08	14.47
Third party actions	-	0.08	0.10	0.08	0.05	0.30
Total	**11.55**	**19.74**	**22.80**	**20.22**	**15.60**	**89.91**

11.5.1 SCADA & Communications

Similar to section 10.5.2, the Western Power approach to transmission SCADA & Communications investment and operations has until recently been predominately reactive, with investment focused almost exclusively on repair of failed equipment. As a result, the current Western Power transmission SCADA & Communications equipment is in poor condition and represents a risk to the safe and reliable performance of the transmission network.

The key issues[168] that Western Power has identified in the NMP are:

- technical obsolescence of transmission SCADA & Communications assets
  - multiplexing, microwave and tele-protection equipment based on obsolete technology and no longer supported by manufacturer
  - copper pilot cables in degraded condition and performance, and with 68% of pilot cable population in service more than 10 years past the intended 35-year asset life
- non-compliance with new AEMO Power Systems Data Communications Standard

[166] Western Power Excel model *8.3 - Western Power AA4 capital expenditure and capital contribution model,* worksheet *Capex calcs*

[167] Ibid.

[168] Western Power, *Network Management Plan 2017/18 - 2027/28*, August 2017, table 242, pp. 206-7

- [redacted]
- technical obsolescence of master stations, with obsolete and unsupported computing hardware and software and elevated cyber security risk

Western Power has advised the following details of the main projects for the functional like-for-like replacement of obsolete telecommunication and automation assets, as part of the strategic move to a proactive approach to asset management of SCADA & Communications.

Table 59 Transmission SCADA & Communications - asset replacement projects ($M real direct costs at 30 Jun 2017)[169]

Project	Scope	Status	Estimating method	AA4 cost
Replace Tx SCADA/Comms equipment: SCAR3	Remote Terminal Units Multiplexors Microwave Teleprotection supporting systems	Scoping	Top-down	25.1
Replace Tx Pilot Cables: STG3	Pilot cables	Scoping	Top-down	12.3
Replace Tx SCADA/Comms equipment: SCAR2	Microwave radios Remote Terminal Units Multiplexors Narrowband radio supporting systems	Execution	Bottom-up	12.3
Deploy Tx control systems	Remote Terminal Units Protection panels	Execution	Bottom-up	2.2
Total				**51.9**

Western Power has advised that top-down estimating methods rely on historical costs for replacing equipment on a like-on-like basis. These estimates are subsequently developed through the scoping and planning phase of the project into bottom-up estimates that incorporate details of specific sites and equipment configurations.

In AA3, Western Power commenced a program to replace copper pilot cables with fibre optic, with the initial plan to address thirteen sites mainly in the Perth metropolitan area. This work progressed during AA3, but was in part deferred due to changing priorities for other projects and business transformation initiatives.

Work also commenced during AA3 updating the master station, with the initial focus on upgrading the XA/21 hardware which had been in service beyond the current industry standard asset life and was no longer supported by the vendor. The software upgrade was deferred pending energy market rules/re-organisation and a decision on master station convergence.

We did not have the opportunity to review any detailed estimates for forecast costs for AA4, but note the following:

- The AA4 program is a continuation of the asset replacement and renewal program commenced in AA3. This program was reviewed as part of the AA3 proposed access arrangement review, and considered

[169] Western Power email response to RFI GHD011 10 November 2017

prudent.[170] GBA was not able to assess the proposed costs during their review due to a lack of detailed information available to them.

- In their draft report on the NFIT review of AA3 CAPEX, GBA noted that AA3 actual expenditure was less than that proposed, and comparable to AA2 actual expenditure, and was focused on the replacement of SCADA & Communications assets.

We agree with GBA's conclusion in their AA3 proposed access arrangement review that given the importance of SCADA & Communications to the operation of the transmission network, the replacement of obsolete equipment is reasonable. A recent benchmarking study conducted by GHD into industry practices for managing SCADA & Communications infrastructure concluded that all of the participants in the study considered "*… they were more proactive than Western Power (based on Western Power's historical SCADA/Comms strategy).*"[171] The benchmarking study noted that a change to a more proactive strategy will require additional CAPEX, although this investment "*… will start to align Western Power with other network operators*".[172] However, there are expected to be benefits in reduced OPEX associated with the increased CAPEX (refer section 13.6.6.2).

In comparison with other transmission utilities, the current Western Power CAPEX per circuit kilometre is well below the average expenditure for other industry participants, and that the forecast expenditure in 2018/19 would be more comparable with the industry average.

Given that Western Power has changed its asset strategy for SCADA & Communications from a reactive to largely proactive, and that the existing network is aged, technical obsolete and lacking manufacturer support, we are of the opinion that the forecast AA4 expenditure allowances are "catch-up" to bring Western Power in-line with a majority of transmission electricity utilities in the Australian market. Whilst we have been unable to review the forecast CAPEX in detail, given the benchmarking study found that the proposed Western Power AA4 forecast expenditure is comparable to industry average CAPEX per circuit kilometre, we are of the opinion that the proposed CAPEX allowances for AA4 are reasonable.

We recommend that the CAPEX allowances proposed for the AA4 period are accepted.

11.6 Summary

The following tables summarise our recommended CAPEX forecasts by regulatory category and in total.

For the growth component, we are satisfied from our analysis of the sample of projects reviewed that the capital estimates proposed by Western Power are reasonable, and we are therefore satisfied to accept the full growth project portfolio as proposed.

Table 60 Recommended asset replacement CAPEX ($M real direct costs at 30 June 2017)[173]

Transmission asset replacement	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Switchboards	67.4	3.0	8.1	7.2	7.8	11.1	37.3

[170] Geoff Brown & Associates, *Technical Review of Western Power's Proposed Access Arrangement for 2012-2017*, 27 March 2012, Appendix B4.3, p. B11

[171] GHD, *Investigation into Industry Practices for Managing SCADA and Telecommunications Infrastructure*, August 2017, p. iii

[172] Ibid., p. iii

[173] Ibid.

Transmission asset replacement	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Power transformers	52.4	2.5	8.6	7.8	5.7	7.3	32.0
Protection - replacement	40.3	4.6	3.9	3.9	3.9	3.9	20.1
Static VAr Compensator	36.2	3.0	3.0	3.0	3.0	2.6	14.6
Primary plant	46.8	6.9	8.7	10.4	7.0	6.8	39.7
Replacement other	2.2	0.7	0.5	0.5	0.5	0.1	2.2
Total	**245.2**	**20.7**	**32.8**	**32.8**	**27.9**	**31.7**	**145.9**

Table 61 Recommended regulatory compliance CAPEX ($M real direct costs at 30 June 2017) [174]

Transmission regulatory compliance	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Poles and towers	60.0	12.6	12.6	12.7	11.2	11.1	60.0
Cross arm replacement	4.8	1.0	0.9	0.9	0.9	0.9	4.8
Substation security	72.1	2.5	2.5	2.5	2.5	2.5	12.5
Transformers	12.7	0.4	5.2	3.5	2.5	1.1	12.7
Protection	2.3	0.5	1.8	-	-	-	2.3
Cables	3.0	-	-	0.1	0.2	2.7	3.0
Total	**155.0**	**16.9**	**23.0**	**19.7**	**17.3**	**18.4**	**95.3**

[174] Western Power Excel model *8.3 - Western Power AA4 capital expenditure and capital contribution model,* worksheet *Capex calcs*

Table 62 Recommended growth CAPEX ($M real direct costs at 30 June 2017)

Transmission growth	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Capacity expansion							
Midwest	0.4	0.3	0.1	0.0	-	-	0.4
Supply	149.1	18.6	20.2	10.0	25.7	12.5	86.9
Thermal management	9.8	0.7	0.5	0.4	0.6	7.7	9.8
Voltage	40.5	5.0	4.5	6.2	3.2	2.5	21.3
Subtotal	*199.8*	*24.6*	*25.2*	*16.6*	*29.4*	*22.6*	*118.4*
Customer driven							
Customer access	70.7	14.1	14.1	14.1	14.1	14.1	70.7
Line relocations	23.6	4.7	4.7	4.7	4.7	4.7	23.6
Subtotal	*94.3*	*18.9*	*18.9*	*18.9*	*18.9*	*18.9*	*94.3*
Total	**294.1**	**43.5**	**44.0**	**35.6**	**48.3**	**41.5**	**212.7**

Table 63 Recommended service improvement CAPEX ($M real direct costs at 30 June 2017)

Transmission improvement in service	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Reliability driven	0.00	-	-	-	-	-	0.00
SCADA & Communications							
Asset replacement	52.7	8.2	10.8	10.5	11.1	12.1	52.7
Compliance	13.0	0.4	2.0	4.1	3.6	3.0	13.0
Corporate	9.4	1.8	3.1	3.1	1.0	0.4	9.4
Master station	14.5	1.2	3.7	4.9	4.5	0.1	14.5
Third party actions	0.3	-	0.1	0.1	0.1	0.1	0.3
Total	**89.9**	**11.6**	**19.7**	**22.8**	**20.2**	**15.6**	**89.9**

Table 64 Recommended AA4 transmission CAPEX ($M real direct costs at 30 June 2017)

Transmission CAPEX	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Asset replacement	245.2	20.7	32.8	32.8	27.9	31.7	145.9
Regulatory compliance	155.0	16.9	23.0	19.7	17.3	18.4	95.3
Growth	294.1	43.5	44.0	35.6	48.3	41.5	212.7
Improvement in Service	89.9	11.6	19.7	22.8	20.2	15.6	89.9
Total	**784.2**	**92.6**	**119.6**	**110.7**	**113.7**	**107.2**	**543.9**

12. Forecast CAPEX - corporate

12.1 Western Power AA4 proposal

Western Power has forecast corporate CAPEX of $568.9 million (excluding equity raising costs), in real FY2016/17 terms, which represents 13% of total CAPEX for AA4. This represents a 151% increase in spend over the AA3 period. This major increase reflects strategic decisions by Western Power to make significant investments to its corporate asset base to counter underspending in previous periods. In addition to increasing capital spending, Western Power has proposed to incorporate its Fleet into the regulated asset base.

Table 65 shows a comparison of AA3 and forecast AA4 corporate CAPEX.

Table 65 Comparison of AA3 and AA4 corporate CAPEX ($M real at 30 June 2017)[175] [176] [177]

Network	Regulatory category	AA3 approved	AA3 actual	AA4 forecast	Growth Actual AA3 vs AA4
Distribution	IT	105.2	98.5	176.3	79%
	Business support	88.0	56.0	225.1	302%
Transmission	IT	63.5	44.0	70.2	60%
	Business support	53.1	28.4	97.2	242%
Total		**309.8**	**226.9**	**568.9**	**151%**

Western Power's proposed spend over the period is dominated by the timing of two events. The first and largest is the depot modernisation program. This program is scheduled to start in 2017/18 with the highest level of spending to be completed in 2019/20. The second event impacting spending is the capitalisation of leased Fleet assets. The timing for this event to occur is driven by a change in accounting standards which is set to take place in 2019/20.

Table 66 shows the forecast corporate CAPEX in AA4 by regulatory category and activity in real FY2016/17 dollars.

[175] Includes real cost escalation and indirect costs

[176] Western Power Excel model *10.4 - AA4 Regulatory Revenue Model.xlsx*, worksheet *Dx_Inputs* rows 111 to 156 and worksheet *Tx_Inputs* rows 101 to 137 and Excel model *Attachment 8.3 Western Power AA4 capital expenditure and capital contribution model*

[177] Excludes equity raising costs

Table 66 Forecast corporate CAPEX for AA4 ($M real at 30 June 2017)[178]

Regulatory category	Regulatory activity	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Business support	Corporate real estate	28.2	51.7	138.0	12.1	9.9	239.9
	Fleet CAPEX	11.9	6.1	9.2	7.2	12.9	47.3
	Fleet lease	-	-	17.9	0.6	12.4	30.9
	Property, plant & equipment	0.8	0.9	0.9	0.9	0.9	4.3
IT	Business driven	48.3	47.1	35.0	27.4	22.2	179.9
	Business infrastructure	10.3	14.4	20.2	13.2	8.6	66.6
Total		**99.5**	**120.2**	**221.1**	**61.2**	**66.8**	**568.9**

For AA3, Western Power underspent their approved capital expenditure allocation of $334.6 million by approximately 25%, and for AA4, Western Power is proposing an increase on AA3 actual expenditure of approximately $317.5 million, due to increases in both IT and business support activities.

Table 67 shows the AA4 proposed forecast CAPEX (direct costs only) for regulatory compliance activities.

Table 67 AA4 proposed compliance CAPEX ($M real direct costs at 30 June 2017)[179]

Regulatory category	Regulatory activity	2017/18	2018/19	2019/20	2020/21	2021/22	Total AA4
Business support	Corporate real estate	23.3	43.2	116.6	9.9	8.1	201.1
	Fleet CAPEX	11.8	6.1	9.1	7.1	12.6	46.7
	Fleet lease	-	-	17.7	0.6	12.1	30.4
	Property, plant & equipment	0.8	0.8	0.8	0.8	0.8	4.2
IT	Business driven	39.9	39.3	29.5	22.4	18.1	149.3
	Business infrastructure	8.5	12.1	17.0	10.8	7.0	55.3
Total		**84.4**	**101.5**	**190.8**	**51.6**	**58.7**	**487.1**

12.2 Business support activities

12.2.1 Corporate Real Estate

[redacted] [redacted]

[redacted]

[178] Ibid.

[179] Western Power Appendix *8.3 - Western Power AA4 capital expenditure and capital contribution model.xlsx*, worksheet *Capex calcs,* columns H to M

[redacted]

12.2.1.2 Assessment

We have reviewed the business case and noted the following:

- The process to forecast the capital costs estimate in this CAPEX category contained in the AA4 submission is based on a structured approach using independent/external specialists to assist in formulating the budgets.
- The process commenced with concept plans being developed based on a detailed understanding of the property outcomes sought by Western Power. These concept plans were developed by an architectural firm engaged by Western Power following extensive consultation with internal stakeholders. The consultation with internal stakeholders identified the requirements of the business. These concept plans were provided to an independent Quantity Surveyor who provided a detailed cost estimate of delivering the property, based on the concept plans. These estimated costs are used as the basis for the initial budgets. As each individual project progresses with designs refined and final costings submitted from developers engaged to deliver projects, budgets are reviewed and adjusted accordingly. The process adopted by Western Power is robust and should enable it to accurately forecast budgets.
- The justification of the depot modernisation program is provided in the initial submission documentation (refer section 12.2.1.3).
- [redacted]
- [redacted]

12.2.1.3 Depots

During AA3, Western Power undertook only essential care and maintenance of its depots. These facilities were generally in poor condition, and at the end of their economic life. A health and safety review identified several major issues:

- many existing depots are 40-50 years old and are poorly designed
- site flooding in heavy weather
- asbestos throughout buildings
- poor separation of vehicle traffic and pedestrians
- constrained work environment

[redacted]

[redacted]

We are of the opinion that, given the competitiveness of the construction market, an open tender will elicit a highly accurate cost for the development of the new depot.

Consequently, we are satisfied that market forces should ensure that costs are efficient, and we therefore recommend the AA4 provisions proposed by Western Power are accepted.

12.2.1.4 Property, Plant & Equipment

We reviewed the $4 million (excluding indirect costs and excluding real cost escalation) proposed for the Property, Plant & Equipment (PPE) program within the corporate business support CAPEX. We note that this proposed expenditure is separate to the corporate real estate program and it relates to the provision of operational equipment for operational staff based across the Western Power Depot network.

In previous Access Arrangements, the annual provision for PPE in AA2 was $5.2 million and $6.0 million per annum during AA3. The forecast allowance of $0.85 million per annum for AA4 is relatively modest and reflects the current optimisation program for depots and the associated field equipment, and therefore we recommend this forecast is accepted.

12.2.1.5 Conclusion

From our assessment:

- given the independent nature of the AA4 forecast for facilities [redacted] we accept the allowances as reasonable
- we are of the opinion the annual provision for PPE expenditure is efficient compared to previous Access Arrangements, and therefore we recommend the proposed CAPEX allowances be accepted

12.2.2 Fleet

During AA3, Western Power undertook a number of initiatives that reduced fleet costs and the number of vehicles that are required by the organisation to meet its obligations. We commend Western Power for these initiatives in reducing costs.

As a result of these changes, Western Power has forecast Fleet CAPEX will be $77 million over the AA4 period compared to expenditure of $112 million during AA3. Western Power is proposing to spend $30 million on light vehicles and $47 million on heavy vehicles. During the AA4 period, Western Power will be impacted by a change in accounting standards requiring operating lease assets be recognised as an asset (and the future payments as a liability).

In its AA4 submission, Western Power has also proposed to recover its costs associated with its plant and vehicle fleet directly through the access arrangement rather than indirectly through recovery of costs via OPEX and CAPEX. The latter approach has been used in the first three access arrangement periods.

Currently, the plant and vehicle costs within Western Power have been ring fenced from the access arrangement cost base. Plant and vehicle costs have been charged to operating and capital works on a usage basis ($ per hour). This means that these costs are expensed directly against the works and in the case of capital works, the costs are included in the regulated asset base. This approach has a number of benefits including that it is agnostic to ownership of the plant and vehicle fleet and is transparent in terms of plant and vehicle costs associated with various categories of work.

In Western Power's submission and subsequent presentation they have not provided a rationale for this proposed change, or explained how they will account for Fleet usage after the change in asset classification has been made.

Having reviewed this proposal we have identified the following issues with this approach;

- Complexity – Western Power will be required to book plant and vehicle costs to individual jobs for purposes of its statutory accounts. It is proposing that costs associated with Western Power owned vehicles will be excluded from its regulated costs for CAPEX works. This will require a complex reconciliation process to quantify differences between the statutory accounts and the regulatory accounts.
- Building blocks – Western Power's building block costs used in a bottom-up approach to determine the forecast costs of works have previously included costs associated with plant and vehicles. In its forecast of capital and operating costs for AA4, we are of the opinion that Western Power has not demonstrated that these costs have been excluded from the building block costs.
- Asset ownership – The proposal is not agnostic to ownership of the plant and vehicle fleet. There is no guarantee that in the long term, Western Power will continue to own its fleet, or even a reduced proportion of the fleet. If the ownership profile was to change then the proposed change would have a minimal impact on RAB, while still requiring a complex reconciliation process to be maintained.

12.2.2.1 Recommendation

We recommend that the ERA rejects the Western Power proposal to move fleet assets into the RAB, and exclude the proposed total $77.1 million allowance for fleet (Fleet CAPEX and Fleet lease) from the CAPEX forecast.

12.3 IT activities

Western Power is proposing to spend $205 million on IT over the AA4 period. This is an $88 million or 76% increase on actual expenditure during the AA3 period. A large part of the increase is catch-up investment in corporate IT systems that has been deferred over previous review periods. Consequently, Western Power proposes to replace a number of large systems during the AA4 period.

IT expenditure is split into two categories: Business Driven and Business Infrastructure. Business Driven is the larger area of investment, totalling $149 million of the $205 million budget.

12.3.1 Business Driven

The key Business Driven projects that Western Power is planning to undertake in the AA4 period are:

- Distribution and transmission network management systems used by the asset management and network planning - $30 million

  The continued investments in asset management systems will build on the investments made during the AA3 period. A key element of this investment will include the replacement of the current operational system which is out of date and unsupported as the vendor is no longer in business. Replacing this system will enhance operation of the network as well as improve efficiency in managing and maintaining the network, together with supporting a number of other initiatives Western Power is undertaking over the AA4 period.

- Customer Relationship Management (CRM) - $24 million

  The investment in a revised CRM system is driven by two key factors:

  - the need to replace the existing system that is over 10 years old

- o a desire for better enable customer engagement

  The aim of the new system is to create an integrated system that covers a disparate number of elements including customer quotations, fault reporting, metering, and vegetation management and work orders. From our review of this forecast expenditure, we accept that there is a requirement for a new and comprehensive system. However, following our internal discussions with our IT specialists, including staff with extensive experience in CRM systems, we believe the forecast CAPEX allowance for a new CRM system is excessive. We are of the opinion there are a number of different potential solutions that could work well for Western Power, including a number of Software as a Service (SaaS) products that could materially reduce the CAPEX required to implement a new CRM.

  As we do not have sufficient detail on the CRM project to propose an alternate estimate for a CRM upgrade, we recommend that the ERA accepts the proposed AA4 allowance of $24 M for this project, but also requests Western Power to re-assess the planned expenditure, particularly with consideration of solutions that require a lower investment in regulated assets.

- AMI - $15 million

  The investment in advanced metering IT software is tied directly to the overall advanced metering business case. This business case is assessed elsewhere in this document. In reviewing this business case, we have made a recommendation to change the option that is adopted by Western Power (refer section 10.2.3). We have recommended that the proposed allowances for AMI are not accepted.

- Human Resource Information System (HRIS) and Payroll - $7 million

  We consider the investment in a cloud-based HRIS solution is justified and reasonable.

The balance of the Business Driven CAPEX is associated with works management, and corporate and compliance activities.

12.3.2 Business Infrastructure

Business Infrastructure spend covers investment in the core IT infrastructure including computers and servers, operating systems and desktop applications. Western Power is proposing to spend $55 million over the AA4 period in this area.

The most important projects proposed in the AA4 period are:

- upgrading of the Enterprise Resource Planning (ERP) system
- upgrade the SPIDA geographical information system (GIS) and its associated systems

The ERP system, Ellipse, is commonly used by electricity network companies. The version currently operated by Western Power is eight years old and is no longer supported by the vendor. Updating the system will improve functionality and efficiency as well as reduce risks from operating an unsupported system.

The SPIDA GIS enables the accurate and timely analysis of the network and upgrading this system will enhance pole management and the operation of the network, and facilitate additional operational efficiencies.

Given we accept that it is important that these critical asset and network management systems are current and supported, we recommend the proposed investment in Business Infrastructure of $55 M is accepted.

12.4 Summary

We recommend:

- the investments in depot redesign refurbishment and consolidation be accepted as proposed by Western Power as these should provide a benefits in safety, operational efficiency and security of tenure
- the proposed inclusion of Fleet assets into the regulated asset base should be rejected by the ERA as we are of the opinion that the disadvantages of including these in the RAB appears to outweigh any perceived benefits, and not accept the proposed Fleet CAPEX and Fleet lease allowances totalling $77.1 M
- the ERA requests Western Power to review their proposed solution and explore low capital solutions to the CRM needs, as we are of the opinion that the level of investment in CRM systems appears high and the proposal included in the application does not take into account less capital intensive options
- that the proposed $15 M ICT component of AMI in IT Business Driven be disallowed
- the proposed investment in IT Business Infrastructure for upgrading of ERP and GIS systems be accepted as we are of the opinion that it is reasonable

Table 68 shows the recommended corporate CAPEX forecast for AA4.

Table 68 Recommended corporate CAPEX ($M real direct costs at 30 June 2017)

Corporate	Proposed AA4 CAPEX	Recommended AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Business Support							
Corporate real estate	201.1	23.3	43.2	116.6	9.9	8.1	201.1
Fleet CAPEX	46.7	-	-	-	-	-	-
Fleet lease	30.4	-	-	-	-	-	-
Property, plant & equipment	4.2	0.8	0.8	0.8	0.8	0.8	4.2
Subtotal	*282.4*	*24.2*	*44.1*	*117.4*	*10.7*	*8.9*	*205.3*
IT							
Business driven	149.3	29.9	37.3	28.6	21.5	16.9	134.3
Business infrastructure	55.3	8.5	12.1	17.0	10.8	7.0	55.3
Subtotal	*204.6*	*38.4*	*49.4*	*45.7*	*32.3*	*23.9*	*189.6*
Total	**487.1**	**62.6**	**93.4**	**163.1**	**43.1**	**32.8**	**394.9**

13. Forecast OPEX

13.1 Western Power AA4 OPEX proposal

Table 69 shows Western Power's OPEX proposal in $'000 real at 30 June 2017, including indirect costs.

Table 69 Western Power proposed AA4 OPEX ($'000 real at 30 June 2017) [180]

Category	Base Year	AA4 period					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Transmission							
Operations - SCADA & Comms	10,880	9,962	9,747	9,600	9,834	9,799	48,942
Operations - Network	4,654	4,500	4,465	4,465	4,456	4,436	22,322
Maintenance - Preventive Condition	13,624	12,683	12,409	12,223	12,521	12,476	62,312
Maintenance - Preventive Routine	20,538	19,116	18,703	18,423	18,872	18,803	93,917
Maintenance - Corrective Deferred	9,447	8,699	8,511	8,384	8,588	8,557	42,739
Maintenance - Corrective Emergency	2,164	2,015	1,972	1,942	1,990	1,982	9,902
Other - Non-recurring OPEX	5,328	5,990	5,860	5,772	5,913	5,892	29,427
Sub-total	*66,635*	*62,966*	*61,667*	*60,810*	*62,174*	*61,945*	*309,560*
Distribution							
Operations - Reliability	1,452	1,355	1,344	1,332	1,376	1,386	6,792
Operations - SCADA & Comms	5,541	5,170	5,128	5,082	5,251	5,290	25,921
Operations - Network	14,845	14,515	14,599	14,691	14,786	14,886	73,477
Maintenance - Preventive Condition	25,265	24,007	23,812	23,601	24,385	24,566	120,371
Maintenance - Preventive Routine	54,741	50,798	50,384	49,938	51,598	51,980	254,697
Maintenance - Corrective Deferred	16,653	15,556	15,429	15,292	15,801	15,918	77,995
Maintenance - Corrective Emergency	68,731	59,500	59,015	58,493	60,437	60,885	298,331
Customer - Call Centre	3,866	3,888	3,910	3,935	3,960	3,987	19,679
Customer - Metering (network)	3,106	2,784	2,761	2,737	2,827	2,848	13,957
Customer - Metering (non-network)	11,677	11,499	11,565	11,638	11,713	11,792	58,207
Customer - GSL Payments	1,011	1,016	1,022	1,028	1,035	1,042	5,143
Customer - Distribution Quotations	6,682	5,963	5,915	5,862	6,057	6,102	29,900
Other - Non-recurring OPEX	11,371	11,931	11,834	11,729	12,119	12,209	59,824
Sub-total	*224,941*	*207,982*	*206,715*	*205,358*	*211,347*	*212,892*	*1,044,295*

[180] Western Power OPEX model *AA4 operating expenditure and indirect cost model* to the ERA, worksheet *BST calcs*

Category	Base Year	AA4 period					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Corporate							
Superannuation benefit scheme	199	200	200	201	202	202	1,004
EnergySafety levy	4,434	4,446	4,455	4,476	4,494	4,511	22,381
ERA fees	1,124	1,629	1,129	1,135	1,139	1,654	6,685
Business Support	77,709	109,134	78,337	77,704	77,830	78,122	421,127
Sub-total	*83,466*	*115,408*	*84,121*	*83,515*	*83,665*	*84,490*	*451,198*
Total	**375,041**	**386,356**	**352,503**	**349,683**	**357,186**	**359,327**	**1,805,054**

13.2 Base year for AA4 OPEX forecast

Western Power has proposed a base year of 2016/17, in which it states that the actual level of expenditure reflects the savings achieved through their business transformation program over the previous two years. It is noted that the actual OPEX real direct expenditure for the 2016/17 year was $318 million; or $375 million including indirect costs (totalling $57 million).

To establish the direct revenue cap efficient base year (refer Table 70), Western Power proposed the following adjustments to 2016/17 actual costs:

- Actual 2016/17 financial year expenditure less the non-revenue cap services was $440 million.
- Indirect costs incurred during 2016/17 of $57 million were removed - these costs relate to overhead costs recovered by the work program for both capital and operating expenditure. In removing these costs, a base year total can be determined for forecast expenditure in AA4. These indirect costs are captured and applied as overheads as per Western Power CRAM.
- An adjustment of $71 million due to business support costs of $71 million that are not required for AA4 - business transformation costs of $56 million as the program will now not be continuing during all of the AA4 period, and allocated costs associated with the Electricity Market Review of $15 million which were originally included in response to an anticipated transition from the Western Australian regulatory regime to the AER national regulatory regime, but which has been postponed indefinitely by the current Western Australian Parliament.
- Removal of a provision of $6 million previously included for the Midwest 330 kV line project as this is no longer required.

From this process, the proposed direct revenue cap value is **$318 million** for the base year.

Table 70 Western Power AA4 proposed base year ($'000 real at 30 June 2017) [181]

Category	Actual 2016/17 costs	AA4 base year			
		Indirect costs	Actual less Indirect	Step change	Total
Transmission					
Operations - SCADA & Comms	10,880	2,572	8,308	-	8,308
Operations - Network	4,654	129	4,525	-	4,525
Maintenance - Preventive Condition	13,624	3,046	10,578	-	10,578
Maintenance - Preventive Routine	20,538	4,595	15,943	-	15,943
Maintenance - Corrective Deferred	9,447	2,192	7,255	-	7,255
Maintenance - Corrective Emergency	2,164	483	1,681	-	1,681
Other - Non-recurring OPEX	-972	332	-1,304	6,300	4,996
Sub-total	*60,335*	*13,348*	*46,987*	*6,300*	*53,287*
Distribution					
Operations - Reliability	1,452	335	1,117	-	1,117
Operations - SCADA & Comms	5,541	1,277	4,264	-	4,264
Operations - Network	14,845	410	14,435	-	14,435
Maintenance - Preventive Condition	25,265	5,465	19,800	-	19,800
Maintenance - Preventive Routine	54,741	11,845	42,896	-	42,896
Maintenance - Corrective Deferred	16,653	3,823	12,830	-	12,830
Maintenance - Corrective Emergency	68,731	15,658	53,073	-	53,073
Customer - Call Centre	3,866	-	3,866	-	3,866
Customer - Metering (network)	3,106	810	2,296	-	2,296
Customer - Metering (non-network)	11,677	243	11,435	-	11,435
Customer - GSL Payments	1,011	1	1,010	-	1,010
Customer - Distribution Quotations	6,682	1,764	4,918	-	4,918
Other - Non-recurring OPEX	11,371	1,530	9,841	-	9,841
Sub-total	*224,941*	*43,161*	*181,780*	*0*	*181,780*
Corporate					
Superannuation benefit scheme	199	-	199	-	199
EnergySafety levy	4,434	-	4,434	-	4,434
ERA fees	1,124	-	1,124	-	1,124
Business Support	148,508	924	147,584	-70,799	76,785

[181] Western Power OPEX model *AA4 operating expenditure and indirect cost model* to the ERA, worksheets *Base year* and *BST calcs*

Category	Actual 2016/17 costs	AA4 base year			
		Indirect costs	Actual less Indirect	Step change	Total
Sub-total	*154,265*	*924*	*153,341*	*-70,799*	*82,542*
Total	**439,541**	**57,433**	**382,108**	**-64,499**	**317,609**

The base year value of $318 million comprises the following:

- $182 million of recurring OPEX on the distribution network
- $53 million of recurring OPEX on the transmission network
- $83 million of recurring corporate OPEX

13.3 OPEX forecast

Western Power has proposed trending from the base year of $318 million as follows:

- Adjust for step changes in recurrent OPEX:
  - an annual reduction of $5 million in OPEX has been proposed by Western Power as an overall cost reduction method
- Adjust for network growth:
  - Distribution network growth factors are based on forecasts of customer numbers, maximum demand, energy delivered, connection points, circuit length and maximum demand, based on the volume of work associated with the distribution network and network development.
  - Transmission network growth factor assumes increases in network length in all years of the AA4 regulatory period, based on projected customer connection requirements, maximum demand, energy delivered, connection points, network capacity augmentation requirements, and line decommissioning planned for AA4.
- A cumulative efficiency factor of 1% per annum has been applied across all years of the AA4 period, as a provision for anticipated productivity improvements from BTP initiatives during AA4
- Forecast non-recurrent expenditure during AA4 (refer section 13.3)
- Inclusion of forecast expensed indirect costs
- Labour rates were escalated in accordance with the rate of growth in the wage index for WA electricity, gas, water and waste water services

The top-down forecast of OPEX during AA4 is shown in Table 71 with a projected total OPEX of $1.8 billion over the 5-year period to 2021/22.

Table 71 Top-down development of proposed AA4 OPEX ($'000 real at 30 June 2017)[182]

Item	Base Year	AA4 period					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
AA4 base year	317,609	317,609	317,609	317,609	317,609	317,609	1,588,045
Annual reduction		-5,000	-5,000	-5,000	-5,000	-5,000	-25,000
AA4 recurrent OPEX sub-total		*312,609*	*312,609*	*312,609*	*312,609*	*312,609*	*1,563,045*
Escalation - network growth		2,940	5,892	9,376	12,649	15,709	46,565
Efficiency dividend		-3,155	-6,338	-9,563	-12,816	-16,091	-47,963
Non-recurrent OPEX		32,533	1,183	198	-	500	34,414
Expensed indirect costs		40,043	36,772	33,315	39,366	39,499	188,995
Escalation - labour		1,386	2,385	3,749	5,378	7,101	19,999
Total		**386,356**	**352,503**	**349,683**	**357,186**	**359,327**	**1,805,054**

The AA4 forecasts have been developed using a top-down approach, similar to the base-step-trend method used by the AER for electricity utilities in the NEM. This approach is consistent with the method adopted by Western Power for AA3 and accepted by the ERA, which used a "base year" which reflects business-as-usual recurring OPEX with adjustments for known operating conditions during AA4.

13.4 OPEX forecast adjustments

13.4.1 Annual reduction

Western Power has proposed an annual negative $5 million step change for efficiencies anticipated to be achieved during AA4 due to BTP initiatives. These include:

- refining the vegetation management process, through a risk-based approach and alternate practices
- reducing overtime through improved systems and process governing approval of overtime when responding to network faults

We accept these provisions.

13.4.2 Scale escalation

Western Power has applied two[183] distinctive growth trends for distribution and transmission, and a resulting weighted average corporate value.

The growth factors have been based on the following variables:

- Distribution network growth factors are based on forecasts of customer numbers, circuit length and maximum demand, based on the volume of work associated with the distribution network and network development.

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[182] Western Power Appendix *7.5 Western Power operating expenditure and indirect cost model.xlsx*, worksheet *Summary*

[183] Excluding indirect costs growth trend which is the weighted average of transmission and distribution growth rates

- Transmission network growth factor assumes increases in network length in all years of the AA4 regulatory period, based on projected customer connection requirements, network capacity augmentation requirements, and line decommissioning planned for AA4.

This approach is consistent with recent decisions from the AER for electricity distribution (TasNetworks September 2016).[184] and transmission (Powerlink September 2016).[185] utilities in the NEM. In addition, we note that Western Power has adopted the weightings for the variables for distribution and transmission network growth factors consistent with the recommendations of Economic Insights in their benchmarking report.[186] to the AER in 2014.

Table 72 summarises the network growth factors for distribution and transmission proposed by Western Power for AA4, and Table 73 shows the weighted average for corporate OPEX proposed for AA4, based on the Cost and Revenue Allocation Method (CRAM) and the distribution/transmission cost split from the 2016/17 regulated financial statements.

Table 72 Distribution and transmission network scale escalation factors

Variable	Weighting [187]	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Distribution							
Customer numbers	67.6%	1.65%	1.73%	1.69%	1.66%	1.63%	
Circuit length	10.7%	0.91%	0.91%	0.91%	0.91%	0.91%	
Annual average growth in highest max demand	21.7%	0.00%	0.00%	0.00%	0.00%	0.00%	
Distribution growth	*100.0%*	*1.21%*	*1.26%*	*1.24%*	*1.22%*	*1.20%*	
Compound growth		*1.21%*	*2.49%*	*3.77%*	*5.03%*	*6.30%*	*1.23%*
Transmission							
Circuit length	28.7%	0.32%	0.33%	0.22%	0.33%	0.32%	
Annual average growth in highest max demand	22.1%	0.00%	0.00%	0.00%	0.00%	0.00%	
Energy volumes delivered	21.4%	0.30%	0.00%	2.89%	2.50%	0.00%	
Annual average growth in entry & exit points	27.8%	-0.24%	-0.70%	-0.25%	-0.98%	0.00	

[184] AER, *Draft Decision - TasNetworks distribution determination 2017/18 to 2018/19: Attachment 7 - operating expenditure*, September 2016. The AER accepted the TasNetworks OPEX forecast for the 2017-19 period, noting that TasNetworks was operating efficiently relative to other NEM businesses, and relied upon historic actual costs for their (AER's) forecast analysis with growth factors in line with the AER standard approach. The AER alternative OPEX forecast was higher than that proposed by TasNetworks.

[185] AER, *Powerlink transmission draft determination 2017-22: Attachment 7 - Operating expenditure*, September 2016. The AER accepted the Powerlink OPEX forecast as proposed for the 2017-22 period, noting that it was lower than the actual spend during 2012-17. However, the AER also stated that whilst their benchmarking suggested Powerlink was not operating as efficiently as other NEM transmission businesses, the benchmarking was not sufficiently robust to support an alternative forecast for base OPEX. Powerlink acknowledged it has scope for efficiency improvements and included efficiency measures in their proposal that reduced their base OPEX by 12.2%.

[186] Economic Insights, *Economic benchmarking of operating expenditure for NSW and ACT electricity DNSPs*, 17 November 2014, pp. 9-10. In the Powerlink draft decision for OPEX, the AER noted that in this Economic Insights report, they discuss "*… the process for selecting the output specification in its economic benchmarking assessment of opex for the NSW and ACT electricity distributors.*"

[187] Weightings as nominated in TasNetworks and Powerlink proposals

Variable	Weighting [187]	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Transmission growth	*100.0%*	*0.09%*	*-0.11%*	*0.62%*	*0.35%*	*0.09%*	
Compound growth		*0.09%*	*-0.02%*	*0.59%*	*0.95%*	*1.04%*	*0.21%*

Table 73 Weighted average corporate growth factors

Network	Weighting [188]	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Distribution	73.2%	1.21%	1.26%	1.24%	1.22%	1.20%	1.23%
Transmission	26.8%	0.09%	-0.11%	0.62%	0.35%	0.09%	0.21%
Combined growth	*100.0%*	*0.91%*	*0.90%*	*1.08%*	*0.99%*	*0.91%*	
Compound growth		*0.91%*	*1.81%*	*2.91%*	*3.93%*	*4.87%*	*0.96%*

Table 74 shows the total network growth adjustment applied to the top-down forecast proposed by Western Power for AA4 OPEX.

Table 74 Western Power proposed scale escalation for AA4 OPEX ($,000 at 30 June 2017)

Item	AA4 period					
	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Escalation - distribution network	2,142	4,404	6,657	8,899	11,132	33,234
Escalation - transmission network	47	-12	316	506	556	1,414
Escalation - corporate	752	1,499	2,403	3,244	4,021	11,918
Total	**2,940**	**5,892**	**9,376**	**12,649**	**15,709**	**46,565**

We have reviewed the annual variables for the distribution and transmission networks and note:

- **Distribution**
  - The customer numbers for the distribution network do not directly correlate with the numbers provided in Appendix 7.3 to the AA4 AAI; however, the difference in percentage changes year-on-year are immaterial, and therefore we are satisfied to use the customer numbers as provided in modelling to the ERA.[189]
  - We note that Western Power has based its circuit length growth on historic AA3 distribution network growth, due to forecasting accuracy difficulties. We accept that these difficulties are valid, as the review of AA3 CAPEX[190] has noted that actual AA3 distribution growth CAPEX was 28% less than the approved allocation due to a depressed state economy, and renewable generation

[188] Based on the distribution/transmission cost split from the 2016/17 regulated financial statements

[189] Western Power provided the OPEX model *AA4 operating expenditure and indirect cost model* to the ERA, which was consistent with the model *7.5 - Western Power AA4 operating expenditure and indirect cost model (CONFIDENTIAL)* as provided as supplementary information to the AA4 Access Arrangement Information submission

[190] Geoff Brown & Associates, *Review of Western Power's Actual Capital Expenditure during AA3 (2012-2017)*

and energy efficiency initiatives being adopted by customers in lieu of previously planned network augmentations. Therefore, we accept using actual AA3 changes in network length as a proxy for changes in AA4, as we anticipate there will be similar underspend in growth CAPEX due to changing customer requirements and associated project deferrals. The annual change of 0.91% is considered reasonable, in relation to the projected change in customer numbers during AA4.

  - There is no forecast increase in peak demand for the distribution network during AA4.

- **Transmission**
  - Similar to the distribution circuit length, Western Power has relied upon changes in line length during AA3 as a proxy for forecast changes in AA4 due to forecasting accuracy difficulties. The AA3 CAPEX review has identified that 40 of 68 planned capacity expansion projects for AA3 did not proceed, primarily to changes in customer requirements, and the total expenditure on new customer connections was 83% lower than approved for AA3. We therefore accept that it is difficult to forecast changes in circuit length for AA4, and the modest 0.30% annual change proposed by Western Power is considered reasonable.
  - As for the distribution network, there is no increase forecast for peak demand during AA4.
  - The increase in transmission energy volumes are based on the energy and customer number forecasts[191] for AA4. These AA4 energy volume forecasts considered the increasing penetration of renewable generation and energy storage systems.
  - Consistent with the increased amount of renewable generation anticipated for AA4, Western Power has proposed small decreases in the number of entry & exit points for AA4, which we consider reasonable.

- **Corporate**
  - As shown in Table 73, Western Power has proposed scale escalation factors for corporate OPEX, based on the distribution/transmission expenditure split from the 2016/17 regulated financial statements. We do not accept that it is reasonable to apply scale escalation to business support activities, such as IT, levies, fees and insurances, as these are not proportional to any growth in service outputs that may result from changes in customer demand.[192] Therefore, we have not allowed for any scale escalation in our alternative AA4 OPEX forecast.

We note that Western Power has based its scale escalation factors on weightings previously used by electricity utilities in the NEM as part of their regulatory submissions to the AER in 2016/17. These weightings were based on advice from Economic Insights to the AER in the benchmarking studies in 2014 as reflecting the appropriate weightings based on the cost data available at that time. The values shown in Table 11 and Table 12 in the benchmarking analysis (refer section 7) are based on latest NSP cost and revenue information available to the AER.[193] [194]

[191] Western Power, *Attachment 7.3.5 Energy & Customer Numbers Forecast - 2017: Access Arrangement Information*, 2 October 2017

[192] In the explanatory statement to their expenditure forecast assessment guideline, the AER recognised that OPEX forecast expenditure should consider any increased demand for NSP's outputs that may require an expansion of the network, and that an efficient NSP will require more inputs to deliver more output.

[193] Economic Insights, *Position Paper for Review of TNSP Economic Benchmarking*, 9 August 2017, p. 31

[194] Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report*, 31 October 2017, section 1.1, p. 1

Based on these revised weightings, we have calculated the scale escalation factors as shown in Table 75.

Table 75 Revised distribution and transmission scale escalation factors

Variable	Weighting [195]	2017/18	2018/19	2019/20	2020/21	2021/22	CAGR
Distribution							
Customer numbers	45.8%	1.65%	1.73%	1.69%	1.66%	1.63%	
Circuit length	23.8%	0.91%	0.91%	0.91%	0.91%	0.91%	
Annual average growth in highest max demand	30.4%	0.00%	0.00%	0.00%	0.00%	0.00%	
Distribution growth	*100.0%*	*0.97%*	*1.01%*	*0.99%*	*0.98%*	*0.97%*	
Compound growth		*0.97%*	*1.99%*	*3.00%*	*4.01%*	*5.02%*	*0.98%*
Transmission							
Circuit length	38.0%	0.32%	0.33%	0.22%	0.33%	0.32%	
Annual average growth in highest max demand	19.0%	0.00%	0.00%	0.00%	0.00%	0.00%	
Energy volumes delivered	23.0%	0.30%	0.00%	2.89%	2.50%	0.00%	
Annual average growth in entry & exit points	20.0%	-0.24%	-0.70%	-0.25%	-0.98%	0.00	
Transmission growth	*100.0%*	*0.14%*	*-0.02%*	*0.70%*	*0.50%*	*0.12%*	
Compound growth		*0.14%*	*0.12%*	*0.82%*	*1.33%*	*1.45%*	*0.29%*

Table 76 shows our alternate network growth adjustment to be applied to the top-down forecast for AA4 OPEX.

Table 76 Alternate scale escalation for AA4 OPEX ($,000 at 30 June 2017)

Item	AA4 period					
	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Escalation - distribution network	1,718	3,517	5,308	7,092	8,868	26,503
Escalation - transmission network	75	63	438	707	774	2,057
Escalation - corporate	0	0	0	0	0	0
Total	**1,793**	**3,581**	**5,746**	**7,799**	**9,641**	**28,560**

[195] Weightings as nominated in TasNetworks and Powerlink proposals

13.4.3 Productivity adjustment

In their AAI submission, Western Power has included a compounding 1.0% per annum productivity improvement, based on anticipated ongoing savings during AA4 due to efficiencies achieved through business improvement initiatives and programs during AA3 and into AA4.

Table 77 Proposed productivity adjustment for AA4 OPEX ($,000 at 30 June 2017)

Item	AA4 period					
	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Productivity efficiency (% pa / CAGR)	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	
Productivity efficiency	-3,155	-6,338	-9,563	-12,816	-16,091	-47,963

In 2015, Western Power instigated a BTP to identify potential improvement opportunities in asset management, workforce productivity and management of external spend and business functions. The BTP is credited with achieving a total of approximately $330 million in recurring savings to 30 June 2017, through continuous improvement in:

- refined asset management strategies
- improved field workforce performance
- improved fleet and property management
- enhanced commercial practices in contract spend, materials handling and logistics
- reduced CAPEX

The estimated impact on OPEX due to BTP initiatives during AA3 is reported as a recurring saving of $72 million (as at 30 June 2017).

In the AA3 final decision[196], the ERA imposed an annual compound 2% efficiency factor from 2013/14 to drive efficiency gains identified during the review of the Western Power AA3 submission. This was based on the then forecast efficiency gains of $37 million per annum by 2016/17 that were used by Western Power as justification for the AA3 strategic program of works.

In the explanatory statement to expenditure forecast assessment guidelines, the AER recognised that any productivity forecast "*… should be firm specific given it is intended to reflect the potential productivity change the NSP can achieve in the next regulatory control period.*"[197] If we adopt a similar approach in assessing the proposed productivity efficiency of 1% per annum for AA4, we should recognise the improvements achieved during AA3 and the generally associated lower actual spend compared with the approved allocations for distribution and transmission OPEX (refer sections 13.5 and 13.6).

In this context, together with considering the reduced CAPEX program proposed for AA4, and the additional $5 million per annum reduction included in the AA4 OPEX forecast for anticipated efficiencies (refer section 13.4.1) we consider the proposed efficiency dividend of a compounding 1% per annum to be reasonable for AA4.

[196] ERA, *Final decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 5 September 2012, clause 49, p. 10

[197] AER, *Explanatory Statement: Expenditure Forecast Assessment Guideline*, November 2013, section 5.3.2, pp. 69-70

Based on the new weightings for scale escalation, our alternative forecast for productivity adjustment is located in Table 78.

Table 78 GHD alternative productivity adjustment for AA4 OPEX ($'000 at 30 June 2017)

Item	AA4 period					
	2017/18	2018/19	2019/20	2020/21	2021/22	Total
Productivity efficiency (% pa / CAGR)	-1.0%	-1.0%	-1.0%	-1.0%	-1.0%	
Productivity efficiency	-3,144	-6,292	-9,455	-12,625	-15,793	-47,310

13.4.4 Forecast non-recurrent OPEX during AA4

An adjustment for non-recurrent OPEX of $34.4 M has been included in AA4, in relation to the remaining costs associated with the Business Transformation Process ($28.3 M) and costs associated with the Electricity Market Review related to the transfer of system operations functions to the AEMO, involving relocation of staff from the network control centre in East Perth to the AEMO office in the Perth CBD and the transfer of IT systems.

The Access Code states that for Non-capital costs:

> *6.40 Subject to section 6.41, the non-capital costs component of approved total costs for a covered network must include only those non-capital costs which would be incurred by a service provider efficiently minimising costs.*
>
> *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 if:*
>
> *(a) the alternative option costs do not exceed the amount of alternative option 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 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.*

13.4.4.1 Business Transformation Program

Expenditure for the BTP has previously been included in the *Corporate -Business Support* cost category, and represented $55.7 M of a total $148.5 M Business Support expenditure in the audited regulated financial statement for 2016/17 (refer Table 70).

The BTP commenced in 2015 to identify cost improvement opportunities in business operations, and is credited with achieving $330 M in cost reductions across asset management strategies, field workforce performance and management of contract spend, fleet and property since its inception.

Western Power has advised that the BTP is scheduled to be completed in the 2017/18 financial year. As the program will be wound-up during 2017/18, the annual allocation for the BTP was removed from the base year, and a one-off allocation of $28.3 M included for the final 5 months of the program.

The Western Power AA4 OPEX proposal includes consideration of projected cost savings that will be achieved through the BTP, through both a $5 M per annum reduction for projected efficiencies in vegetation and overtime management and a 1% per annum efficiency dividend based on initiatives commenced in AA3 that will continue to reduce operating costs during AA4.

We recognise that the BTP has been accepted as an approved business-as-usual activity[198] during AA3, and that the annual expenditure on this program has been previously accepted as reasonable in the audited 2016/17 regulated financial statements.

Therefore, we accept that the projected costs to complete the program during 2017/18 are consistent with previous expenditure, and that the expenditure is justified in supporting the cost reduction initiatives included in the Western Power AA4 OPEX proposal.

13.4.4.2 Electricity Market Review

In March 2014, the Electricity Market Review (EMR) was launched to examine the structures of the electricity generation, wholesale and retail sectors within the SWIS. Stage 2 of the EMR included institutional arrangements that transitioned system management and retail market operations to AEMO to improve the co-ordination of system operations (including generator dispatch) with the commercial outcomes of the Wholesale Electricity Market. Legislative amendments related to these changes were gazetted on 30 May 2016, and took effect from 1 July 2016.

This transition includes the relocation of 30 staff from the network control centre in East Perth to the AEMO office in the Perth CBD, and the transfer of IT systems from Western Power to AEMO including record archives, system access and testing. The proposed one-off cost allocations for this transition total approximately $5.1 M during AA4.

Given that the transition has been mandated through legislation, and the relatively immaterial forecast one-off EMR expenditure compared to the total forecast AA4 OPEX, we accept the proposed allocations as reasonable, consistent with the Access Code requirements.

13.4.4.3 Conclusions

We accept the proposed one-off allowances for the final year of the BTP, Stage 2 institutional changes as part of the electricity market review and pass-through ERA regulatory costs, totalling $34.4 M over the AA4 period.

13.4.5 Indirect costs

Expensed indirect costs are management, planning and support services that cannot be directly attributed to operational activities. Indirect costs are categorised as network shared costs (and are allocated based on the CRAM).

The allocation method for each of these three types of shared costs is outlined below:

- Network shared costs

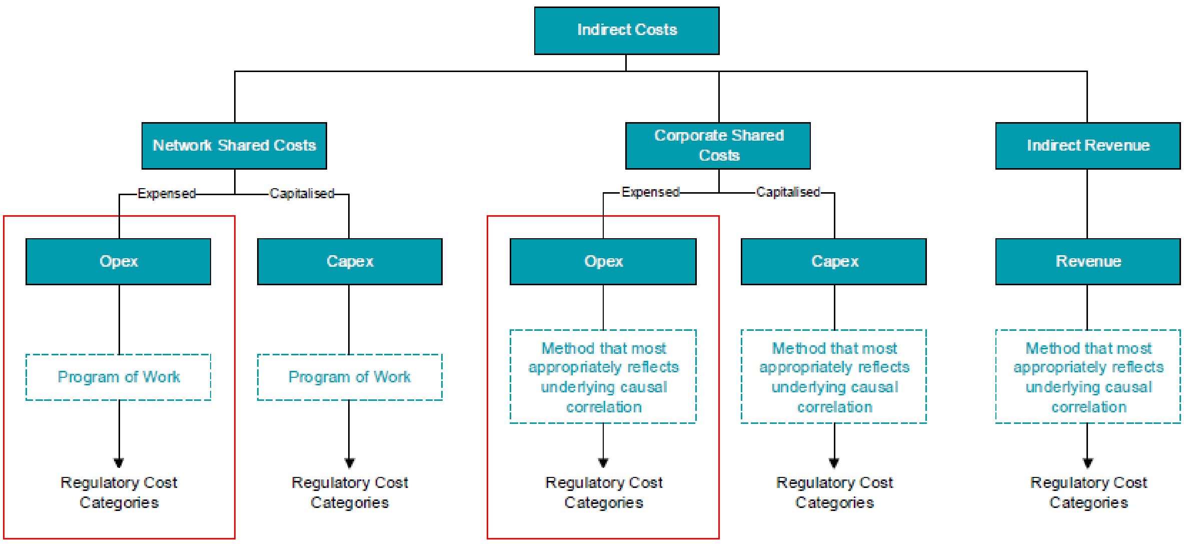
[198] We note that the business improvement program and the projected savings achieved through its initiatives were reported in the 2016 and 2017 Western Power Annual Reports

- These are identified in a “shared cost pool” and allocated using the indirect cost allocation method across the program of work (PoW). This is based on the proportion of direct costs incurred by each service and allows the allocation of network shared costs to the PoW.

- Corporate shared costs
  - These include common or shared functions not directly attributed or indirectly allocated to the PoW, and costs that do not fall within OPEX costs (such as depreciation and amortisation, bad debts etc.)
  - Corporate shared costs are allocated using the method that most appropriately reflects the causal correlation of the underlying transaction. Common causal correlations include allocation on a full time staff equivalents basis (for transactions that have a causal correlation to the consumption of labour) and allocation based on PPE, and intangible assets (for transactions that have a causal correlation to building, maintaining and operating the network)
- Indirect revenue
  - Indirect revenue includes proceeds from the disposal of network planning & operations and corporate related fixed assets, as well as other income
  - Indirect revenue is allocated based on the method that most appropriately reflects the causal correlation of the underlying transaction (the most common method being allocation based on PPE)

A diagram displaying the allocation method of indirect costs (with OPEX highlighted) is located in Figure 36.

Figure 36 Indirect Cost Allocation



OPEX and indirect costs are forecast using the same base-step-trend method (as outlined earlier in this section), but these forecasts are conducted independently of each other.

For the AA4 period, indirect costs are allocated to the following regulatory categories:

Transmission

- Preventive Condition
- Preventive Routine
- Condition Deferred
- Condition emergency
- SCADA & Communications
- Non-recurring OPEX

Distribution

- Preventive Condition
- Preventive Routine
- Condition Deferred
- Condition Emergency
- Reliability Operations
- SCADA & Communications
- Metering - Network
- Customer service - Distribution quotations
- Non-recurring OPEX

Table 79 shows the proposed annual forecast of expensed indirect costs for AA4, compared with the indirect allocations for equivalent transmission and distribution categories in the 2016/17 base year.[199]

Table 79 Proposed AA4 expensed indirect costs ($'000 real at 30 June 2017) [200] [201]

Category	Base Year	AA4 period					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Transmission							
Operations - SCADA & Comms	2,572	1,694	1,539	1,388	1,630	1,622	7,872
Maintenance - Preventive Condition	3,046	2,156	1,960	1,767	2,075	2,064	10,023
Maintenance - Preventive Routine	4,595	3,250	2,954	2,664	3,127	3,112	15,106
Maintenance - Corrective Deferred	2,192	1,479	1,344	1,212	1,423	1,416	6,874
Maintenance - Corrective Emergency	483	343	311	281	330	328	1,593
Other - Non-recurring OPEX	332	1,018	926	835	980	975	4,733
Sub-total	*13,220*	*9,940*	*9,035*	*8,147*	*9,564*	*9,517*	*46,202*
Distribution							
Operations - Reliability	335	230	212	193	228	229	1,093
Operations - SCADA & Comms	1,277	879	810	735	870	875	4,169
Maintenance - Preventive Condition	5,465	4,082	3,761	3,412	4,041	4,065	19,361

199 In the 2016/17 base year regulated financial statements from Western Power OPEX model *AA4 operating expenditure and indirect cost model* to the ERA, worksheet *Base year*, there were indirect allocations included for Network - Operations, non-network metering, GSL payments and corporate categories which have been excluded from this comparison.

200 For AA4 values, Western Power OPEX model *AA4 operating expenditure and indirect cost model* to the ERA, worksheet *BST calcs,* columns BC to BH

201 Excludes non-revenue cap services

Category	Base Year	AA4 period					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Maintenance - Preventive Routine	11,845	8,636	7,958	7,220	8,550	8,602	40,966
Maintenance - Corrective Deferred	3,823	2,645	2,437	2,211	2,618	2,634	12,545
Maintenance - Corrective Emergency	15,658	10,116	9,321	8,457	10,015	10,075	47,984
Customer - Metering (network)	810	473	436	396	469	471	2,245
Customer - Distribution Quotations	1,764	1,014	934	848	1,004	1,010	4,809
Other - Non-recurring OPEX	1,530	2,029	1,869	1,696	2,008	2,020	9,622
Sub-total	*42,507*	*30,103*	*27,738*	*25,168*	*29,802*	*29,983*	*142,794*
Total	**55,727**	**40,043**	**36,772**	**33,315**	**39,366**	**39,499**	**188,996**
Expensed indirect cost as % of total annual regulatory expenditure for categories allocated indirect costs	22.36**%**	17.00%	15.79%	14.46%	16.57%	16.55%	**16.08%**

We have reviewed the calculations provided by Western Power and are satisfied that the base-step-trend method has been applied correctly. However, due to the change in weightings for scale escalation, as well as the subsequent effect on productivity adjustment, the amount of indirect costs we have forecast vary for those calculated by Western Power. The alternate indirect cost forecast for AA4 is outlined in Table 80.

Table 80 GHD alternative AA4 forecast indirect costs ($'000 real at 30 June 2017)[202]

Category	Base Year	AA4 period					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Transmission	13,220	9,949	9,054	8,174	9,615	9,574	46,366
Distribution	42,507	30,044	27,622	25,009	29,560	29,682	141,916
Total	**55,727**	**39,993**	**36,676**	**33,183**	**39,175**	**39,256**	**188,283**
Expensed indirect cost as % of total annual regulatory expenditure for categories allocated indirect costs	22.36**%**	17.01%	15.80%	14.47%	16.59%	16.58%	**16.10%**

13.4.6 Scale escalation factors

Western Power has applied CPI and real labour cost escalators over the regulatory period. The following sections review the scale escalation applied by Western Power for the AA4 OPEX.

[202] Excludes non-revenue cap services

13.4.6.1 CPI

The CPI forecast was based on the RBA short-term outlook and the median of the acceptable range for CPI in the medium term, which resulted in an average annual CPI growth rate of 2.4% (refer Table 81).

Table 81 CPI forecast (% change, financial year average)[203]

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 average
CPI – Australia	2.0	2.5	2.5	2.5	2.5	2.4

We have verified the medium-term forecast to be consistent with the RBA's *Statement on Monetary Policy* of February 2017[204] as the mid-point of end-of-financial-year CPI inflation forecast.

To derive each year's maximum allowable revenue over the regulatory period, Western Power has used forecast CPI to roll forward the regulatory asset base for AA4, and escalated the input costs in real terms.

We note that Western Power has been inconsistent in the value of CPI that has been proposed for AA4 in the Revenue Model. Western Power has used a 1.64% value for CPI, rather than the 2.4% used above.

13.4.6.2 Labour

For the AA3 access arrangement review, there was consideration of the appropriate Australian Bureau of Statistics (ABS) index to be used as the basis for labour cost escalation:

- average weekly ordinary time earnings (AWOTE); or
- wage price index (WPI)

The Final Decision for the AA3 access arrangement considered the WPI approach was more appropriate, as changes in Western Power expenditure was related to changes in labour costs rather than a compositional change in the workforce.

Consequently, Western Power based the labour cost escalation for AA4 on the national WPI for electricity, gas, water and waste services (EGWWS) industries published by the ABS.

Table 82 shows the proposed labour escalation factors used in generating the OPEX forecasts for AA4.

Table 82 Proposed labour cost escalation (WPI) over AA4 period[205]

	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 average
Real wage price growth – EGWWS Western Australia (% p.a. / CAGR)	0.9	0.8	1.0	1.1	1.2	1.0

The labour escalation factors were generated as follows:

- As the ABS does not publish WA-based wage price indices for EGWWS industries, national WPI for EGWWS was adjusted to reflect:

[203] Western Power, *Access arrangement information for the AA4 period*, Attachment 7.4 (Synergies Economic Consulting), Table 2

[204] Table 6.1 of RBA statement

[205] Western Power, *Access arrangement information for the AA4 period*, p.144

- o an increase in wages growth across all industries in Australia, as well as the wages growth in WA, albeit at a slightly lower rate, reflecting the RBA view of a weaker labour market and inflation outlook
- o EGWWS wages in WA to follow a similar profile to those of all industries.

- adjusted from the nominal index using CPI (refer Table 81)

13.4.6.3 Western Power proposed labour weightings

Western Power has based its AA4 proposed labour weighting based on actual costs incurred during 2015/16 and 2016/17, and its definition of labour compared to non-labour components.

Table 83 shows that the calculated split is approximately 40:60 for labour/non-labour costs.

Table 83 Western Power 2015/16 and 2016/17 actual labour/non-labour cost split[206]

Cost Component	2015/16	2016/17	Total	% of Total (excluding Gifted assets)
Labour	$ 453,126,269	$ 393,700,657	$ 846,826,926	38.4%
Contractors	$ 23,552,575	$ 17,125,097	$ 40,677,671	1.8%
Non-Labour	$ 829,714,326	$ 698,075,513	$ 1,527,789,838	59.8%
Total	**$ 1,306,393,169**	**$ 1,108,901,266**	**$ 2,415,294,435**	
Gifted Assets	$ 126,166,034	$ 82,346,834	$ 208,512,869	
Total excluding gifted assets	**$ 1,180,227,135**	**$ 1,026,554,432**	**$ 2,206,781,566**	

The definition of labour as it applies to cost escalation has a significant effect on determining the proportion of labour. In its final decision on SA Power Networks, the AER stated that the labour component includes both labour directly employed by a benchmark efficient service provider and contract labour employed to provide field services (refer section 13.4.7). Western Power appears to have adopted a similar definition of labour. The following were notably excluded from the labour component of calculation, and have therefore been included in the non-labour[207] [208] proportion:

- Redundancy ($49,804,087) – Expense Code 240
- Consultancy ($21,133,034) – Expense Codes 400-407
- Non-labour proportion (as determined by Western Power) of Contractors – Operational ($160,206,779 of $167,317,926) – Expense Code 415
- Contractors – Fee for Service ($139,400,377) – Expense Code 416
- Contractors – DDP ($82,274,199) – Expense Codes 442-443

[206] RFI response ERA013 – Opex model sources – Labour proportion calc – 23 Nov 2017

[207] Refer to Excel model *ERA013 – Opex model sources – Labour proportion calc – 23 Nov 2017* for the expense codes used for each item

[208] Values shown are for 2015/16 only

13.4.6.4 Comparative AER regulatory decisions

From the benchmarking review (refer section 7), we concluded that the electricity utilities in the NEM that are comparable to Western Power are SA Power Networks (distribution) and ElectraNet (transmission) or AusNet Services (combined distribution/transmission utility).

In determining escalation factors, the AER approach is based on a "rate of change" method which considers price and productivity escalation. Price escalation is comprised of labour and non-labour real escalation rates, which are multiplied by their relevant share of labour and non-labour OPEX to obtain an overall price escalation.

13.4.6.4.1 SA Power Networks

In its final decision on SA Power Networks' distribution proposal 2015/16 to 2019/20, the AER:

- accepted CPI as the nominal escalation rate for the non-labour component of OPEX as proposed by SA Power Networks
- did not agree with SA Power Networks proposal to use Enterprise Agreements for the first two years of the regulatory period, or benchmarking of Enterprise Agreements to extrapolate for a further three years, to calculate labour cost escalation
- substituted WPI forecasts for EGWWS in South Australia as representing efficient labour cost escalation

13.4.6.4.2 ElectraNet

In reviewing the ElectraNet 2018-23 regulatory submission, the AER made the following comments:

- CPI was adopted to escalate non-labour costs, as proposed by ElectraNet

Table 84 shows that ElectraNet proposed an average real labour cost escalation factor of 0.61%.

Table 84 ElectraNet 2017 – real labour cost forecast (%) [209]

Labour escalation estimates	2018/19	2019/20	2020/21	2021/22	2022/23	Average 2019-23
Deloitte Access Economics May 2016	0.60	0.70	0.70	0.70	0.70	0.70
BIS Shrapnel January 2017	0.70	0.80	1.10	1.50	1.60	1.10
Average	0.65	0.75	0.90	1.10	1.15	0.91
Weighted average	0.44	0.50	0.60	0.74	0.77	0.61

- The AER made an alternative assessment of 0.63% based on forecasts of real WPI for EGWWS in Victoria.
- ElectraNet applied a 67:33 split for its labour to non-labour costs in calculating the price escalation factor; whilst the AER benchmark for the labour cost proportion is 62%.
- Overall, the AER draft decision concluded the cost escalation proposed by ElectraNet to be efficient.

[209] ElectraNet, *Revenue Proposal 2018-23*, Attachment 7 – Operating Expenditure, Table 7-5, p. 23

13.4.6.4.3 AusNet Services[210]

In its decision, the AER noted the following from the AusNet services regulatory proposal for 2017-22:

- AusNet Services used WPI for EGWWS in Victoria to forecast labour cost escalation, and proposed an escalation factor of 0.69%. The AER deemed in the draft decision that an efficient factor was 0.58%.
- AusNet services proposed a 78:22 split for labour and non-labour costs; the AER adopted their preferred benchmark split of 62:38
- In its final decision, the AER revised the labour cost escalation factor to 0.55%, based on updated WPI data.

13.4.7 Western Power comparison summary

Table 85 shows a comparison of the labour/non-labour splits for Western Power with the benchmark typically used by the AER and selected utilities in the NEM. Consistent with weightings used by Economic Insights in their benchmarking analysis[211] of OPEX for electricity utilities within the NEM, the AER has adopted 62:38 as the efficient split for labour/non-labour costs.

Table 85 Comparison of labour / non-labour splits

Weighting	AER Benchmark	Western Power	SA Power Networks	ElectraNet	AusNet Services
Labour	0.62	0.40	0.46	0.67	0.78
Non-Labour	0.38	0.60	0.54[212]	0.33	0.22

Western Power has a comparative low labour component in comparison with the AER benchmark for utilities within the NEM, although comparable to SA Power Networks who split their costs using different definitions to the AER. From Table 83 in section 13.4.6.2, Western Power has not included redundancy payments as labour costs, and has not included consideration of field service labour for contracted services.

Using Western Power labour escalation (1.0%) and weighting of 40% for labour, Western Power has applied a weighted labour escalation rate of 0.40%, which is significantly lower than other utilities.

Table 86 Comparison of weighted labour escalation rates

Price Escalation	Western Power	ElectraNet	AusNet Services
NSP submission	0.40	0.61	0.69
AER assessment		0.63	0.58
AER final decision		0.61	0.55

210 AER final decision dated April 2017

211 Economic Insights, *Economic Benchmarking of NSW and ACT DNSP Opex*, 17 November 2014

212 AER, *SA Power Networks determination 2015-20: Attachment 7 - operating expenditure*, section B.4.2, p. 7-49. SA Power Networks weighted its OPEX costs as 46% labour, 44% contracted services, 10% materials. The AER noted that "*… what we have included as labour is different to what SA Power Networks has included as labour*" and stated that their labour component "*… includes both labour directly employed by a benchmark efficient service provider and contract labour employed to provide field services.*" In comparing with other service providers in the NEM, the AER concluded that an efficient OPEX weighting split using the SA Power Networks approach was 43% labour, 40% contracted services, 17% materials; and that the total labour weighting in line with the AER definition for a labour component (compared to a non-labour component) would be the mid-point of the labour (43%) and the combined labour and contracted services (83%) weightings or approximately 62%.

13.4.8 Conclusions

In generating their proposed cost escalation factors, we note that Western Power has adopted an approach which is consistent with approaches of other electricity utilities in Australia, comparable to the preferred approach of the AER, and consistent with the previous ERA decision for the AA3 access arrangement period.

The use of CPI for the non-labour component has been broadly accepted by the electricity industry as being the suitable index under current market conditions in Australia. However, we note that Western Power has been inconsistent in the value of CPI that has been proposed for AA4 in the Revenue Model. The non-labour cost escalation has been based on short-term and medium-term forecasts from the RBA; whilst the reason for the CPI value of 1.64% used by Western Power in the Revenue Model is not apparent. We accept that approach used in generating the proposed average non-labour escalation rate of 2.4% is consistent with other electricity utilities.

Western Power has proposed the labour cost escalation factor based on movements in the Wage Price Index for electricity, gas, water and waste services industries, which is consistent with other electricity utilities. However, the proposed labour component split of 40% is lower than that typically applied by the AER in its regulatory reviews, and lower in comparison with the utilities identified in section 13.4.7 as comparable entities. We consider the weighted labour cost escalation factor of 0.40 is acceptable, given it has been based on the Western Power definition for labour costs, and is less than factors that have been previously approved for other NSPs.

13.5 Distribution OPEX categories

Table 87 compares the allocations (including indirect costs) for distribution OPEX categories that were approved and actual spends for the AA3 period, and the forecast allocations for AA4 in $'000s real at 30 June 2017.[213] The allocations exclude consideration of the Smartgrid program which was discontinued during AA3.

The actual expenditure excludes any non-revenue cap services incurred during AA3, and corporate OPEX which is discussed in section 13.7.

[213] Western Power Excel model *10.4 - AA4 Regulatory Revenue Model.xlsx*, worksheet *Dx_Inputs* rows 653 to 673

Table 87 Operating expenditure by regulatory category ($'000 real at 30 June 2017)

Regulatory category	Expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Preventive Routine	AA3 approved	49,426	51,501	52,028	52,489	53,859	**259,303**						
	AA3 actual	46,583	50,485	51,716	53,367	54,741	**256,892**						
	AA4 proposed							50,798	50,384	49,938	51,598	51,980	**254,698**
Preventive Condition	AA3 approved	65,773	66,156	66,640	55,398	57,684	**311,651**						
	AA3 actual	63,662	49,575	48,570	41,318	25,265	**228,390**						
	AA4 proposed							24,007	23,812	23,601	24,385	24,566	**120,371**
Corrective Deferred	AA3 approved	34,630	34,950	35,323	35,637	36,581	**177,121**						
	AA3 actual	29,992	27,546	27,115	24,821	16,653	**126,127**						
	AA4 proposed							15,556	15,429	15,292	15,801	15,918	**77,996**
Corrective Emergency	AA3 approved	81,660	82,306	83,080	83,741	86,088	**416,875**						
	AA3 actual	87,493	88,109	83,467	80,697	68,731	**408,497**						
	AA4 proposed							59,500	59,015	58,493	60,437	60,885	**298,330**
Network Operations	AA3 approved	16,350	16,401	16,460	16,458	16,442	**82,111**						
	AA3 actual	18,988	15,647	16,909	16,351	14,845	**82,740**						
	AA4 proposed							14,515	14,599	14,691	14,786	14,886	**73,477**
Reliability Operations	AA3 approved	2,057	2,075	2,096	2,114	2,173	**10,515**						
	AA3 actual	1,850	1,498	1,834	1,995	1,452	**8,629**						
	AA4 proposed							1,355	1,344	1,332	1,376	1,386	**6,793**

Regulatory category	Expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
SCADA & Comms	AA3 approved	5,606	5,655	5,712	5,761	5,921	**28,655**						
	AA3 actual	4,978	4,915	5,560	5,741	5,541	**26,735**						
	AA4 proposed							5,170	5,128	5,082	5,251	5,290	**25,921**
Metering	AA3 approved	22,407	22,848	23,312	23,699	24,099	**116,365**						
	AA3 actual	27,018	25,010	21,749	17,014	14,783	**105,574**						
	AA4 proposed							14,282	14,326	14,374	14,541	14,641	**72,164**
Design & Estimating - Distribution Quotations	AA3 approved	4,628	4,620	4,752	4,744	4,737	**23,481**						
	AA3 actual	8,392	6,620	4,360	5,574	6,682	**31,628**						
	AA4 proposed							5,963	5,915	5,862	6,057	6,102	**29,899**
Call centre	AA3 approved	8,070	8,234	8,407	8,551	8,690	**41,952**						
	AA3 actual	7,716	5,586	4,401	3,780	3,866	**25,349**						
	AA4 proposed							3,888	3,910	3,935	3,960	3,987	**19,679**
Guaranteed Service Level payments	AA3 approved	1,891	1,884	1,879	1,867	1,853	**9,374**						
	AA3 actual	-961	1,267	625	760	1,011	**2,703**						
	AA4 proposed							1,016	1,022	1,028	1,035	1,042	**5,143**
Non-recurring OPEX	AA3 approved	11,638	12,616	5,049	5,203	5,342	**39,848**						
	AA3 actual	17,819	13,993	13,030	10,208	11,371	**66,420**						
	AA4 proposed							11,931	11,834	11,729	12,119	12,209	**59,824**
Total Distribution OPEX (excluding Smartgrid)	AA3 approved	304,136	309,246	304,738	295,662	303,469	**1,517,251**						
	AA3 actual	313,530	290,251	279,336	261,626	224,941	**1,369,684**						
	AA4 proposed							207,982	206,715	205,358	211,347	212,892	**1,044,295**

13.5.1 Drivers for distribution OPEX

The Western Power NMP states with regard to changes in distribution OPEX between AA3 and AA4:

- "Significant reduction in routine maintenance activities, through the:
  - extension of inspection cycles in areas of lower risks, reduced scope of inspection (based on detailed assessment of value derivation from these activities) and greater understanding of ageing phenomenon of assets; and
  - deployment of enhanced technology (LiDAR) to get more accurate and holistic information on geometric configuration of the network their condition and condition of surrounding environment (for e.g. vegetation).
- Reduction in vegetation management through application of integrated vegetation management (IVM) techniques and modulation of inspection and cutting frequencies through greater understanding of vegetation growth rates.
- Revision of treatment rules of defects to remove the need for treatment of low risk defects that exhibit lower probability of failure/likelihood of consequences".[214]

Western Power report 3 key principles used to achieve distribution OPEX reductions:

1. Optimise work through more appropriate inspection frequencies
2. Improved prioritisation of work
3. Enhanced efficient use of resources

Table 88 summarises the key changes in asset strategy for distribution OPEX between periods AA3 and AA4.

Table 88 Key changes to distribution operating expenditure[215]

OPEX Program	Applicable Regulatory Category	Key principle for change	Key changes
Routine maintenance – Holistic Inspection	Preventive Routine	1 & 2	Western Power has completed a detailed condition assessment of its Dx OH network, and based on the information on ageing phenomenon of wood poles, the inspection frequencies for holistic inspections have been extended from four yearly to six yearly inspections. The frequency cycles are modulated based on the location of the assets. This is predominantly driven by FRZs and PSZs. The scope of work is also reduced for newly renewed wood poles.

[214] NMP, p24

[215] Ibid., p241

OPEX Program	Applicable Regulatory Category	Key principle for change	Key changes
Routine maintenance – LiDAR survey	Preventive Routine, Preventive Condition	2 & 3	Western Power currently undertakes multiple asset surveys (including through holistic inspections) to collect the geometric state of the OH network and its surrounding environment. The existing survey methods are mostly manual, at varying frequencies, and therefore, have inaccuracies and inconsistencies. The introduction of two Dx network-wide LiDAR surveys over the next five years is repeatability and re-useability.
Routine maintenance – Pole base clearing	Preventive Routine	2	Western Power has completed risk assessment for pole base clearing, and found that the cost of carrying out pole base clearing in Low FRZ is considered grossly disproportionate to the risk reduction. Thus the pole base clearing is topped in Low FRZ
Non-routine maintenance	Preventive Condition, Corrective Emergency and Corrective Deferred	1 & 2	Focusing on risk reduction per dollar spent – Targeted asset treatment to make it more effective by not treating low risk assets
Vegetation Management	Preventive Routine, Preventive Condition	1, 2 & 3	Implementation of IVM in targeted areas. IVM has enabled Western Power to undertake a combination of mechanical clearing, herbicide application and tree removal in targeted areas thus gaining long term efficiency, and modulation of inspection and cutting frequency based on a combination of vegetation growth rates and FRZ.
Dedicated Streetlight Metal Poles (DSLMP)	Preventive Condition, Corrective Emergency and Corrective Deferred	1	Focusing on risk reduction per dollar spent – Targeted asset treatment to make it more effective by not treating low risk assets by reassessing the electrical defect

OPEX Program	Applicable Regulatory Category	Key principle for change	Key changes
All (majority in Emergency Response)	All (majority in Corrective Emergency)	3	The effective and efficient use of the resources thus reducing the cost of doing the work Utilisation of appropriate financial treatment – Capitalising cost of the asset that are replaced under emergency/fault Introduction of cost effective material without compromising quality, and Contract negotiations.

Western Power's strategy for line assets can be characterised as a risk-based cost-benefit analysis approach to rectifying assets exhibiting defects. Distribution plant asset management is conducted using a number of different strategies, depending on the risk level of the asset. For those assets assessed to have a low impact, such as surge arresters and low voltage ground mounted switchgear, Western Power will replace defective assets upon failure. Western Power states that their strategy for some medium impact assets, such as distribution transformers and ring main units, is to *"… manage on condition, and replace on failure"*. For other medium impact assets that may have a vital function in delivering safety and reliability of supply, such as overhead high voltage switchgear, Western Power states that their strategy is to *"… mitigate the risks due to failure of these assets based on their condition"*.[216]

13.5.2 Preventive routine

For distribution assets, Western Power conducts both visual and internal inspections of their network, primarily focusing on the overhead network, as this is subject to "…*a higher level of safety risk".* This includes wood poles, which have internal inspections, as well as other poles, which primarily are visually inspected.

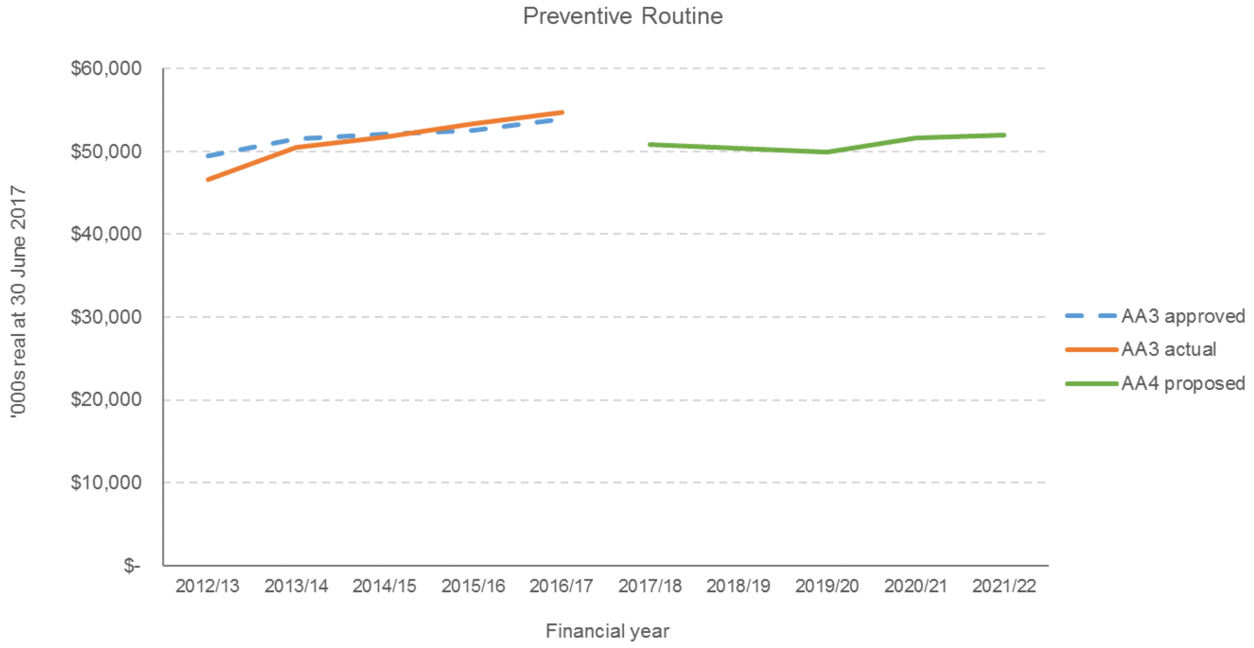
These activities are coded as K1 by Western Power, and are considered necessary to assess the condition of the assets to support optimal CAPEX and OPEX decisions. The key elements of the preventive routine program are:

- Full holistic and visual inspections of the overhead distribution network
- Geometric modelling of overhead distribution circuits to identify any vegetation or clearance issues
- Application of silicone grease to insulators to reduce the likelihood of pole top fires

Figure 37 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

[216] Ibid., section 5

Figure 37 Preventive Routine OPEX AA3 & AA4 ($'000s at 30 June 2017)[217]



The drivers behind the forecasted preventive routine expenditure are discussed in Table 88.

The primary cost drivers during AA4 are:

- Pole inspections extended from 4 to 6 years
- Additional conductor clearance monitoring
- Reduced pole base clearing
- IVM in targeted areas

Therefore, based on the changes in the AA4 cost drivers, we consider that it would be reasonable for cost savings through reduced pole inspection costs to be offset by the additional costs associated with monitoring of ground clearance for overhead lines. The figure above shows that AA4 expenditure is lower than that incurred during AA3 and we consider this reasonable.

13.5.3 Preventive condition

Repairs guided by condition assessments carried out during inspections focus on preventing asset failures that result in safety and reliability issues. For distribution overhead lines, these repairs are predominantly carried out on assets located in areas with high fire and safety risk.

These activities are coded as K2 by Western Power. The key elements of the preventive condition program are:

- Rectification of defects identified during preventive routine maintenance activities, such as:
  - Pole and/or pole top maintenance
  - Conductor damage repair

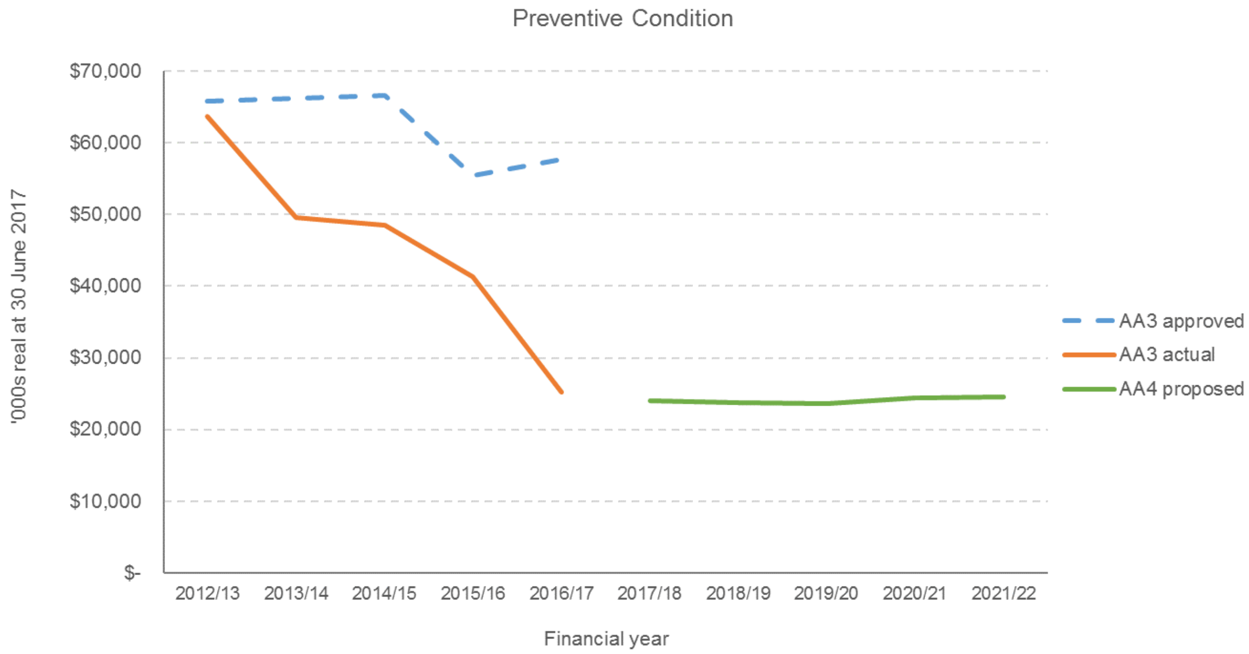
[217] Includes indirect costs

- o Insulator replacement
- o Termite treatment

- Line easement vegetation management to ensure clearance zone maintained
- Mechanical vegetation clearing and herbicides for feeder efficiency
- Application of silicone grease to insulators to reduce the likelihood of pole top fires

Figure 38 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

Figure 38 Preventive Condition OPEX AA3 & AA4 ($'000s at 30 June 2017)[218]



The drivers behind the forecasted preventive condition expenditure are located in Table 88.

The primary cost drivers for AA4 are:

- Reduced preventive condition expenditure on overhead lines due to routine monitoring of ground clearance (refer section 13.5.2).
- IVM
- Focus on risk reduction per dollar spent, which prioritises asset treatment
- Dedicated Streetlight Metal Poles (DSLMP) program

Western Power is proposing to maintain expenditure for preventive condition OPEX during AA4 at the same level incurred during 2016/17. With the expected forecast cost reductions due to LiDAR monitoring of overhead lines, we consider the proposed forecast reasonable.

[218] Includes indirect costs

13.5.4 Corrective deferred

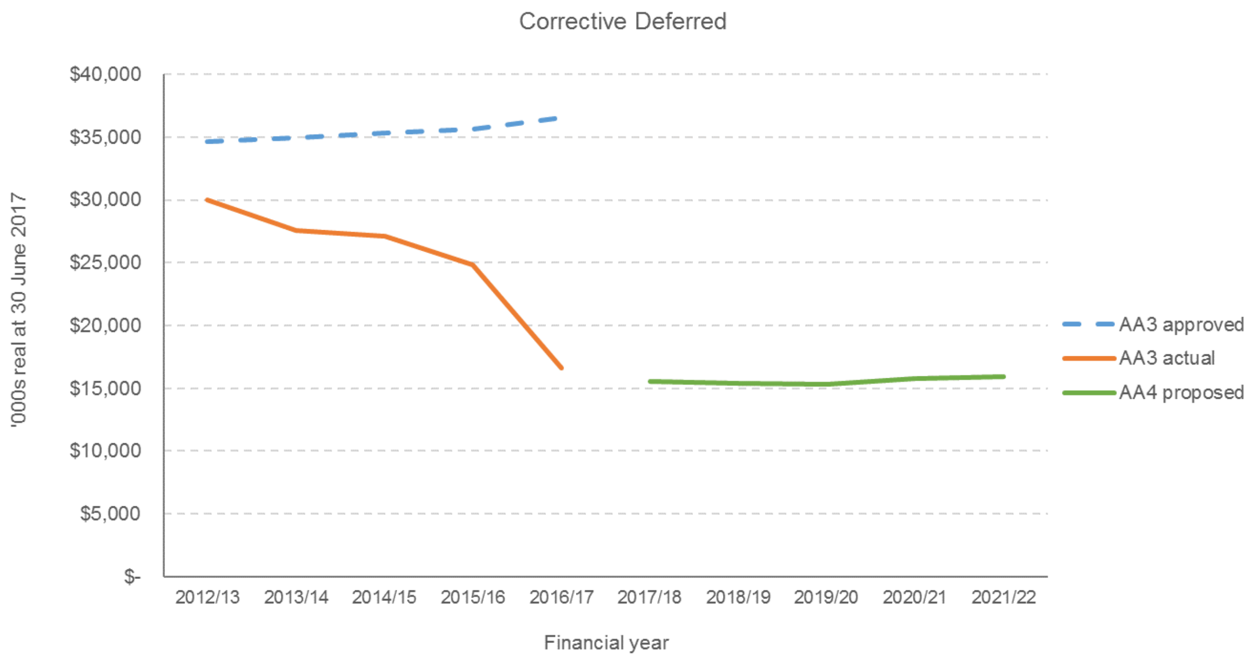
This work is coded as K3 by Western Power and relates to full repairs following temporary repairs undertaken for unplanned outages or asset failure.

The key programs are:

- Emergency overhead and underground line maintenance to address temporary network repairs
- Emergency primary plant maintenance to correct any temporary repairs made to restore supply and situation safe
- Repair of assets damaged as a result of a vehicle collision with a pole

Figure 39 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

Figure 39 Corrective Deferred OPEX AA3 & AA4 ($'000s at 30 June 2017)[219]



The drivers behind the forecasted corrective deferred expenditure are located in Table 88.

The primary cost drivers for AA4 are:

- More efficient preventive maintenance is expected to result in fewer unplanned outages

We note that the forecast expenditure for corrective deferred is significantly less than that approved previously for AA3, and that Western Power incurred lower costs than forecast. With the work efficiencies projected by Western Power as a result of their BTP, we accept the proposed expenditure for AA4.

13.5.5 Corrective emergency

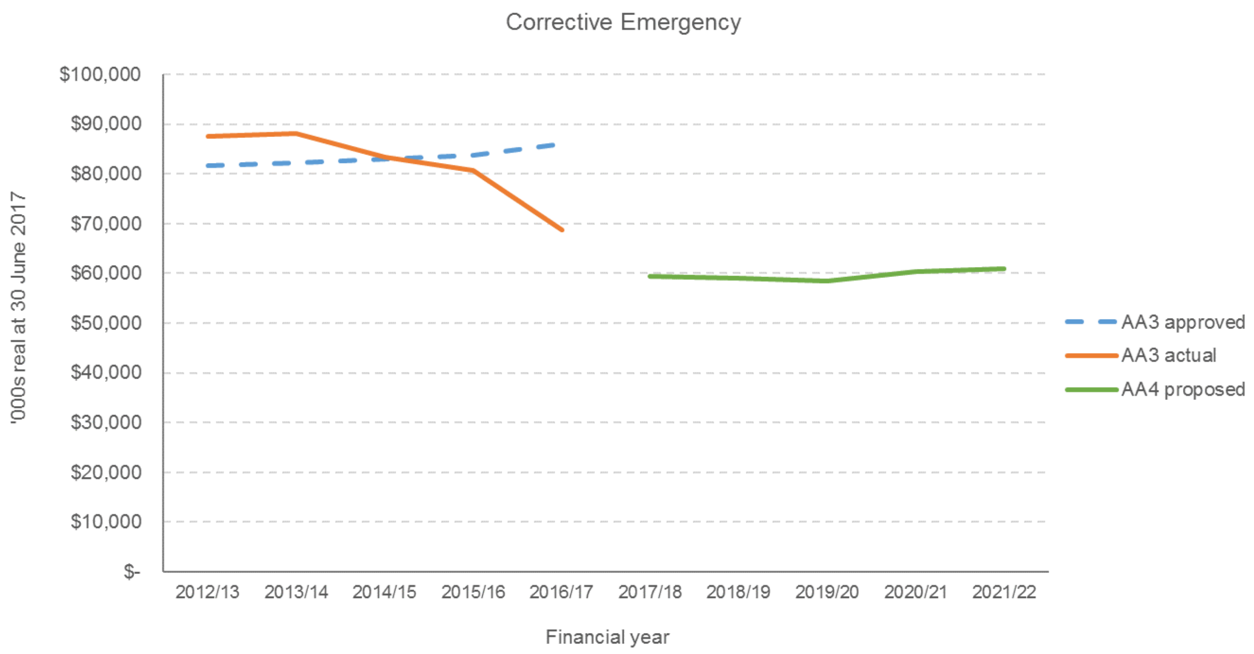
Western Power codes this work as K4, and relates to temporary repair work done to rectify an unplanned outage or asset failure to restore supply or make a situation safe. The key programs are:

[219] Includes indirect costs

- emergency overhead line maintenance to make temporary network repairs
- emergency primary plant maintenance to effect any temporary repairs made as a result of storms or bushfires
- streetlight and streetlight cable fault repairs

Figure 40 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

Figure 40 Corrective Emergency OPEX AA3 & AA4 ($'000s at 30 June 2017)[220]



Corrective emergency expenditure is related to the number of unplanned outages that Western Power has allowed for based on previous network performance during AA3. We note that during AA3, Western Power achieved some reduced expenditure, which we infer is related to improvements in response time to unplanned outages through optimised depot locations (refer section 12.2.1.3), and improved work practices.

We consider it appropriate for the corrective emergency expenditure forecast for AA4 to be at a level lower than that both approved and incurred during AA3 and consider the Western Power forecast reasonable.

13.5.6 Operations

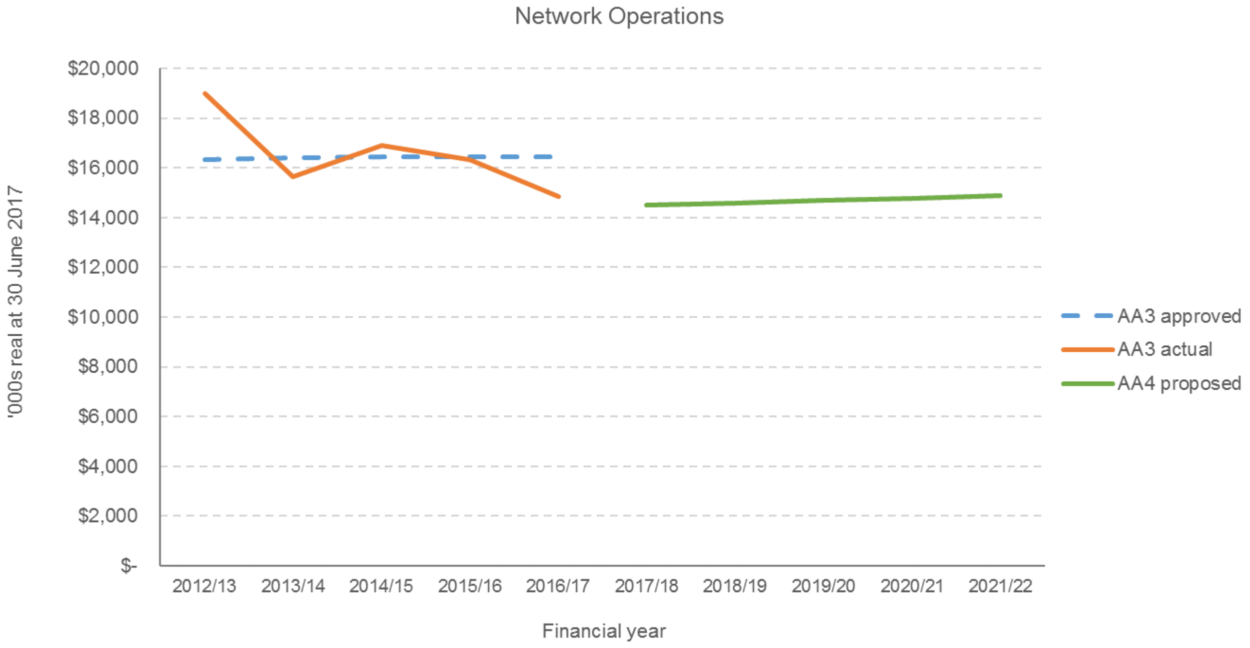
Distribution operations OPEX relates to providing communication within the Western Power Network, planning maintenance and capital works and maintaining reliability through network monitoring and network switching operations.

13.5.6.1 Network operations

Figure 41 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

[220] Includes indirect costs

Figure 41 Network Operations OPEX AA3 & AA4 ($'000s at 30 June 2017)[221]



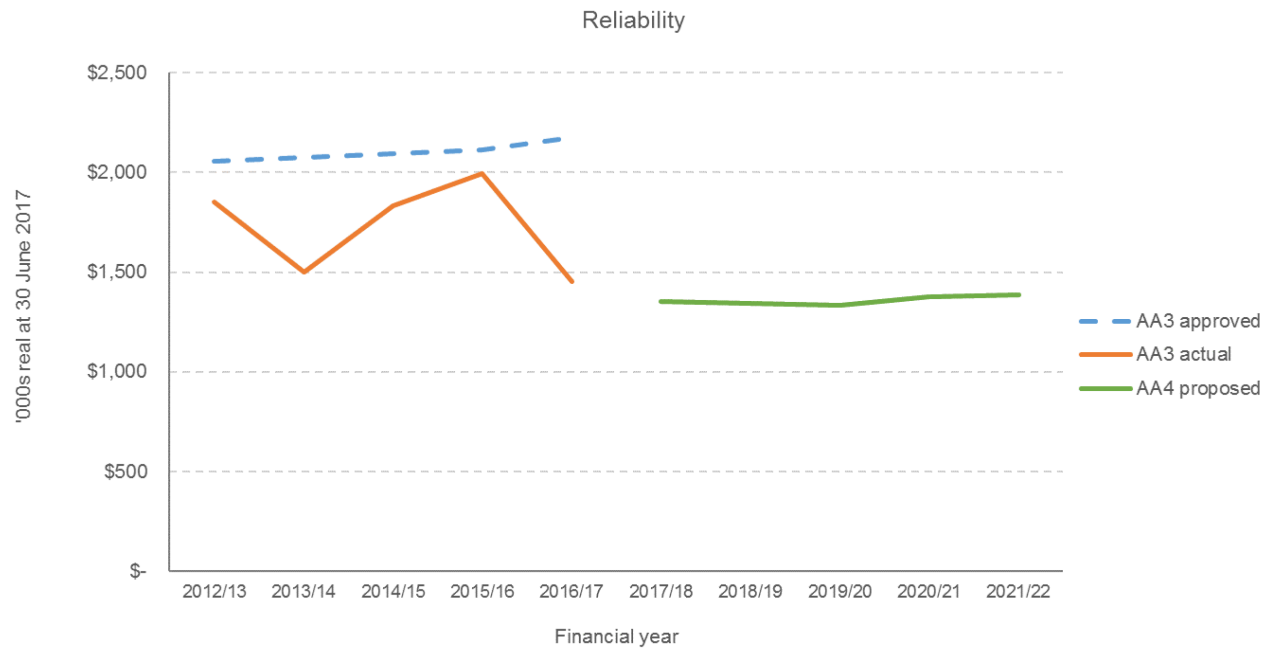
As a result of the BTP during AA3 the number of FTEs that were involved in network operations was optimised. We note that the proposed expenditure for AA4 reflects the actual incurred costs in 2016/17 as the last year of the AA3 period. Therefore, we consider it reasonable for the AA4 forecast to maintain this expenditure level.

13.5.6.2 Reliability operations

Figure 42 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

[221] Includes indirect costs

Figure 42 Reliability OPEX AA3 & AA4 ($'000s at 30 June 2017)[222]



Similar to network operations, Western Power optimised the number of FTEs responsible for monitoring network performance during AA3. We consider it appropriate that projected AA4 expenditure reflects the incurred costs in the last year of the AA3 period and that this is consistent during AA4.

13.5.6.3 SCADA & Communications

SCADA & Communications distribution OPEX includes:

- Real-time monitoring of asset fault trends, equipment alarms and status indications, management of resources and support services
- Non run-to-fail operations, including definition of periodic inspections, and management of resources and maintenance work schedules

Figure 43 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars, based on the Western Power asset strategy during AA3 of being predominately reactive, with investment focused almost exclusively on the repair of failed equipment. For AA4, Western Power has proposed to adopt a more proactive asset strategy, which will align Western Power with other transmission utilities.

A benchmarking study[223] of industry practices for SCADA & Communications found that Western Power has higher than average OPEX costs (measured as cost per circuit kilometre) compared to other Australian electricity distribution businesses.

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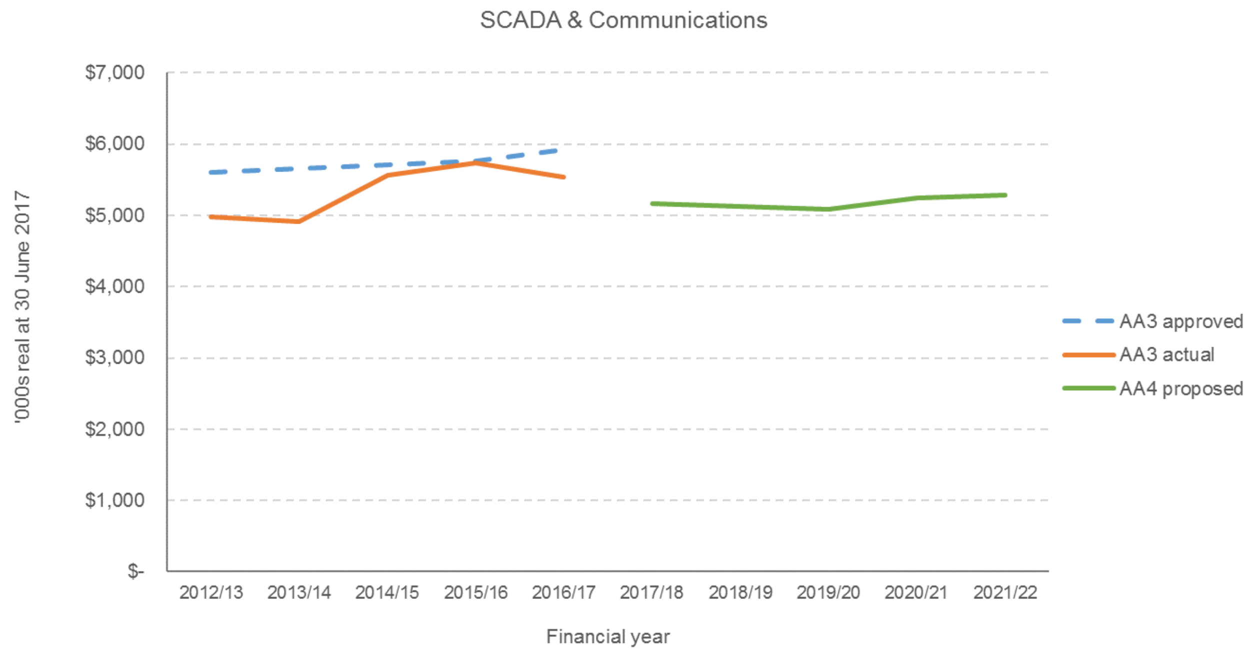
[222] Includes indirect costs

[223] GHD, *Investigation into Industry Practices for Managing SCADA and Telecommunications Infrastructure*, pp ii-iv

Figure 43 SCADA & Communications OPEX AA3 & AA4 ($'000s at 30 June 2017) [224]



There is an extensive SCADA & Communications asset replacement program totalling $32.2 million planned for the AA4 period (refer section 11.5.1). This expenditure compares to a current RAB value at the end of AA3 of $11.9 M, with an average depreciation of approximately $5.7 M per annum.[225]

As a result, we would anticipate there would be a decrease in the corrective element of SCADA OPEX due to the lower maintenance requirements of these newer assets. This is reinforced by findings from a benchmarking report prepared for Western Power in 2017 which observed that "*… any investment program will require an increase in CAPEX over a number of years, particularly given the age and obsolescence of the existing assets. The impact on OPEX will depend upon which assets are replaced; however, a number of other operators have seen reductions in the operating costs after increasing their investment programs.*"[226]

Consequently, we do not accept that it is reasonable for Western Power to propose OPEX expenditure at similar levels to the base year during AA4.

Given the substantial CAPEX relative to the current value of SCADA & Communications assets, we conclude that a significant percentage of the population is planned for replacement during AA4. As a result, we consider that the OPEX allowance for the distribution SCADA & Communications should be reduced to reflect the CAPEX/OPEX trade-off that could reasonably be expected to be achieved.

In the absence of more definitive maintenance costs for new assets, we recommend a nominal 50% reduction, based on an assumption that the asset replacement program will replace at least 50% of the existing SCADA & Communications asset base.

[224] Includes indirect costs

[225] AA4 regulatory revenue model, values as at 30 June 2017

[226] GHD, *Investigation into Industry Practices for Managing SCADA and Telecommunications Infrastructure*, p. iv

13.5.7 Customer service

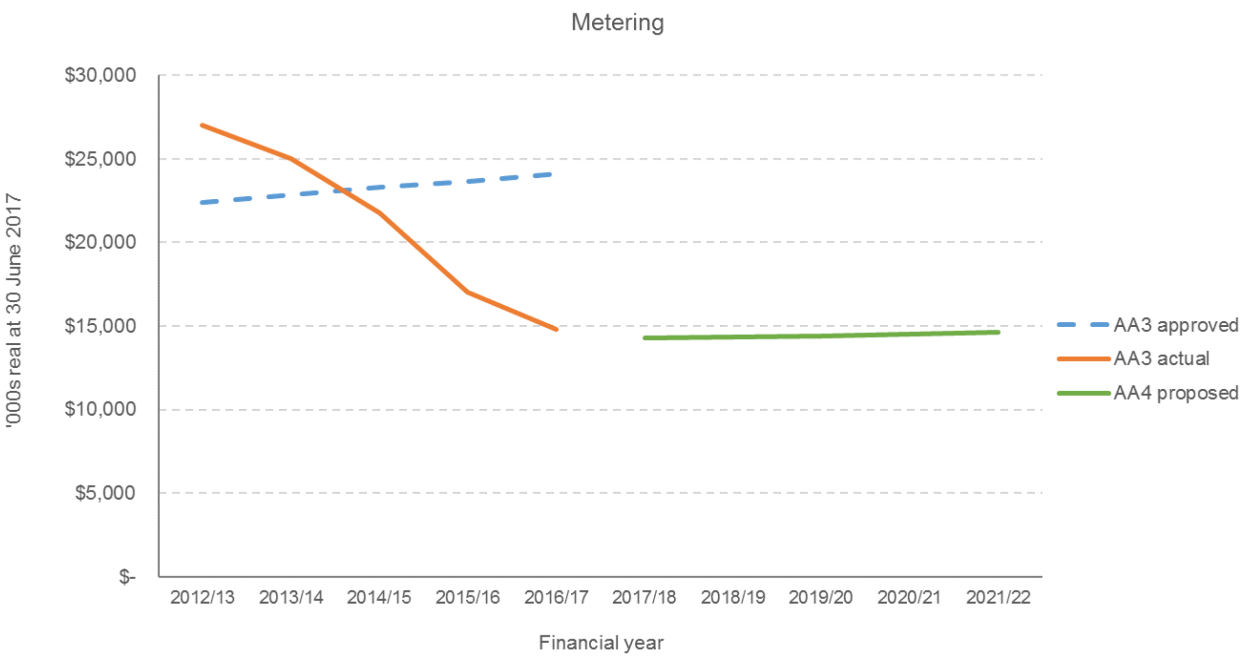
Customer service and billing OPEX maintains service to customers through the Western Power call centre.

As was ruled in the AA3 final decision[227], Guaranteed Service Level (GSL) payments will apply only to extended outages. We recommend the forecast number of eligible customers for payments for extended outages will remain at the level in the final decision for AA3, which is 64,208 (the 2010/11 level of customers). We also recommend the application rate of 30% used in AA3 will apply to AA4 and that the real amount of $8.5 million be applied for AA4. This includes a 10% provision for severe storms, as was included in AA3.

13.5.7.1 Metering

Figure 44 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

Figure 44 Metering OPEX AA3 & AA4 ($'000s at 30 June 2017)[228]



There is a significant AMI Program proposed for AA4, which addresses the replacement of non-compliant or faulty meters. As a result, we would expect the expenditure in AA4 for metering OPEX to be lower than that incurred during AA3, which is reflected in Figure 44. We note that Western Power has included consideration of the impact of the AMI Program in proposing the metering OPEX for AA4.

For the adjusted reduced volumes of meters we have accepted for AA4 (refer section 10.2.3), the annual OPEX allowance has been adjusted by $2.2 million per annum.

[227] ERA, Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network, p92

[228] Includes indirect costs

13.5.8 Findings

The Western Power asset strategy for distribution OPEX as shown in Table 88 outlines the primary drivers for the proposed reductions in expenditure for preventive condition, corrective deferred and corrective emergency for AA4 relative to both forecast and actual AA3 expenditure. Preventive condition expenditure will decrease relative to AA3 expenditure as a result of the reduction of pole base clearing activity in Low FRZs, the introduction of IVM and a risk reduction per dollar spent approach to condition-based maintenance. Both corrective emergency and corrective deferred expenditure for AA4 should reduce due to the REPEX undertaken in AA3, especially for wood poles.

The increase in inspection cycles should reduce the amount of preventive routine OPEX; however, due to the introduction of LiDAR to improve identification of vegetation intrusion, conductor clearances and asset attributes related to geometric network makeup, we consider it reasonable that the cost savings achieved through reduced inspection costs will be offset by these increased monitoring costs.

Based on our review of the forecast expenditure profiles for each of the distribution OPEX categories, we consider that Western Power has projected costs during AA4 for each category at or below the incurred OPEX expenditure for the base year 2016/17 and therefore we accept that the AA4 forecasts reflect the improvements in work practices that Western Power deem were achieved during AA3 and are reasonable. We do not propose any adjustments to these AA4 allocations.

However, we do not accept maintaining OPEX levels for SCADA & Communications at the base year levels for distribution assets during AA4, given the substantial asset replacement program proposed for these networks. We consider that it would reasonable to expect that there would be a CAPEX/OPEX trade-off between the new assets and their lower maintenance requirements. We have proposed a nominal 50% reduction in the OPEX forecast for SCADA & Communications.

13.6 Transmission OPEX

Table 89 compares the allocations (including indirect costs) for transmission OPEX that were approved and actual spends for the AA3 period, and the forecast allocations for AA4 in $'000s real at 30 June 2017.[229]

The actual expenditure excludes any non-revenue cap services incurred during AA3, and Corporate OPEX which is discussed in section 13.7.

[229] Western Power Excel model *10.4 - AA4 Regulatory Revenue Model.xlsx*, worksheet *Tx_Inputs* rows 609 to 636

Table 89 Operating expenditure by regulatory category ($'000 real at 30 June 2017)

Regulatory category	Expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Preventive Routine	AA3 approved	19,368	19,519	19,698	19,852	20,417	**98,854**						
	AA3 actual	23,789	21,857	24,172	23,349	20,538	**113,704**						
	AA4 proposed							19,116	18,703	18,423	18,872	18,803	**93,917**
Preventive Condition	AA3 approved	11,004	11,096	11,206	11,299	11,625	56,230						
	AA3 actual	10,532	9,669	7,761	11,530	13,624	53,116						
	AA4 proposed							12,683	12,409	12,223	12,521	12,476	**62,312**
Corrective Deferred	AA3 approved	11,261	11,346	11,447	11,534	11,849	**57,437**						
	AA3 actual	10,966	9,243	9,240	10,510	9,447	**49,406**						
	AA4 proposed							8,699	8,511	8,384	8,588	8,557	**42,739**
Corrective Emergency	AA3 approved	1,271	1,268	1,268	1,269	1,323	**6,399**						
	AA3 actual	2,313	2,189	2,433	3,116	2,164	**12,215**						
	AA4 proposed							2,015	1,972	1,942	1,990	1,982	**9,902**
Network Operations	AA3 approved	10,843	10,874	10,912	10,908	10,896	**54,434**						
	AA3 actual	7,179	8,409	5,852	5,950	4,654	**32,044**						
	AA4 proposed							4,500	4,465	4,465	4,456	4,436	**22,322**
SCADA & Comms	AA3 approved	13,485	13,594	13,723	13,832	14,209	**68,844**						
	AA3 actual	12,509	11,110	12,105	12,840	10,880	**59,443**						
	AA4 proposed							9,962	9,747	9,600	9,834	9,799	**48,942**

Regulatory category	Expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Non-recurring OPEX	AA3 approved	3,322	1,937	1,742	1,979	2,628	**11,609**						
	AA3 actual	11,548	13,066	22,751	10,276	-972	**56,668**						
	AA4 proposed							5,990	5,860	5,772	5,913	5,892	**29,427**
Total OPEX	AA3 approved	70,555	69,634	69,997	70,672	72,948	**353,806**						
	AA3 actual	78,835	75,542	84,314	77,571	60,335	**376,596**						
	AA4 proposed							62,966	61,667	60,810	62,174	61,945	**309,560**

13.6.1 Drivers for transmission OPEX

The Western Power NMP states with regard to changes in transmission OPEX between AA3 and AA4:

"The expenditure in non-recurring operational expenditure is significantly reduced, owing to greater removal of redundant assets and higher strategic planning costs in AA3. Generally investment across other categories is reduced due to enhancement of asset strategies and more efficient methods of program planning and delivery."[230]

Table 90 summarises the key changes in asset strategy for transmission OPEX between periods AA3 and AA4.

Table 90 Key changes to transmission OPEX[231]

OPEX Program	Applicable Regulatory Category	Key changes
Routine & non-routine maintenance and emergency response	Preventive routine, preventive condition, corrective deferred and corrective emergency	The effective and efficient use of the resources thus reducing the cost of doing the work.
Vegetation Management	Preventive routine, preventive condition	Implementation of IVM in targeted areas. IVM has enabled Western Power to undertake a combination of mechanical clearing, herbicide application and tree removal in targeted areas thus gaining long term efficiency.
SCADA & Communications	Operations	Transmission OPEX remains relatively the same as AA3 except for increase relevant to higher labour and contractual works required to operate and maintain the Transmission telecommunication network to required standard.

The general philosophy for transmission asset management varies between line assets and plant assets. Generally, for plant assets, Western Power states that their strategy is to *"… mitigate the risks due to failure of these assets based on their condition."* For line assets, the general strategy adopted by Western Power is a risk-based cost-benefit analysis approach for assets with identified defects.

13.6.2 Preventive routine

For transmission assets, Western Power states that their strategy is *"… to supplement routine visual inspections with comprehensive condition assessments for key assets including power transformers, circuit breakers and switchboards …* [and] *… condition assessments will also be carried out more frequently for assets with known performance issues.*"[232]

[230] NMP, p24

[231] Ibid., p241

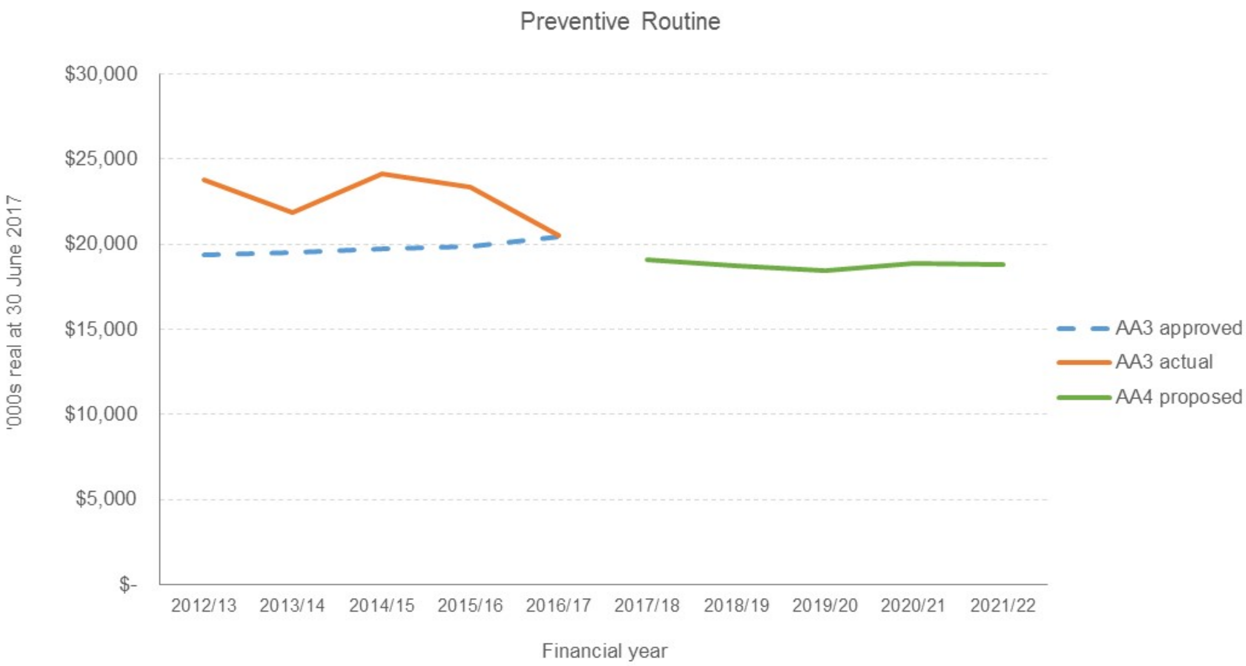
[232] Western Power, *Network Management Plan: Transmission and Distribution Network 2017/18 - 2027/28*, EDM# 34159326, August 2017, section 5.2.2.1, p. 71

These activities are coded as K1 by Western Power, and are considered necessary to assess the condition of the assets to support optimal CAPEX and OPEX decisions. The key elements of the preventive routine program are:

- Pole top inspections and line patrols
- Siliconing of glass/ceramic insulators on 66 kV and 132 kV circuits to reduce the likelihood of pole top fires
- Preventive routine maintenance on all substation primary plant
- Testing of protection and control systems
- Routine electrical testing of power and instrument transformers, indoor switchboards and surge arresters
- Maintenance of substation buildings, switchyards and surrounds
- Geometric modelling of overhead transmission circuits to identify any vegetation or clearance issues

Figure 45 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

Figure 45 Preventive Routine OPEX AA3 & AA4 ($'000s at 30 June 2017) [233]



The drivers behind the forecasted preventive routine expenditure are shown in Table 90.

The primary cost drivers for AA4 are:

- Integrated approach to vegetation management
- Enhanced work practices

[233] Includes indirect costs

The proposed expenditure for AA4 is similar to that incurred in the base year, and is consider to include consideration of efficiencies in revised work practices and the integrated approach to vegetation management. Therefore, we consider this expenditure profile to be reasonable.

13.6.3 Preventive condition

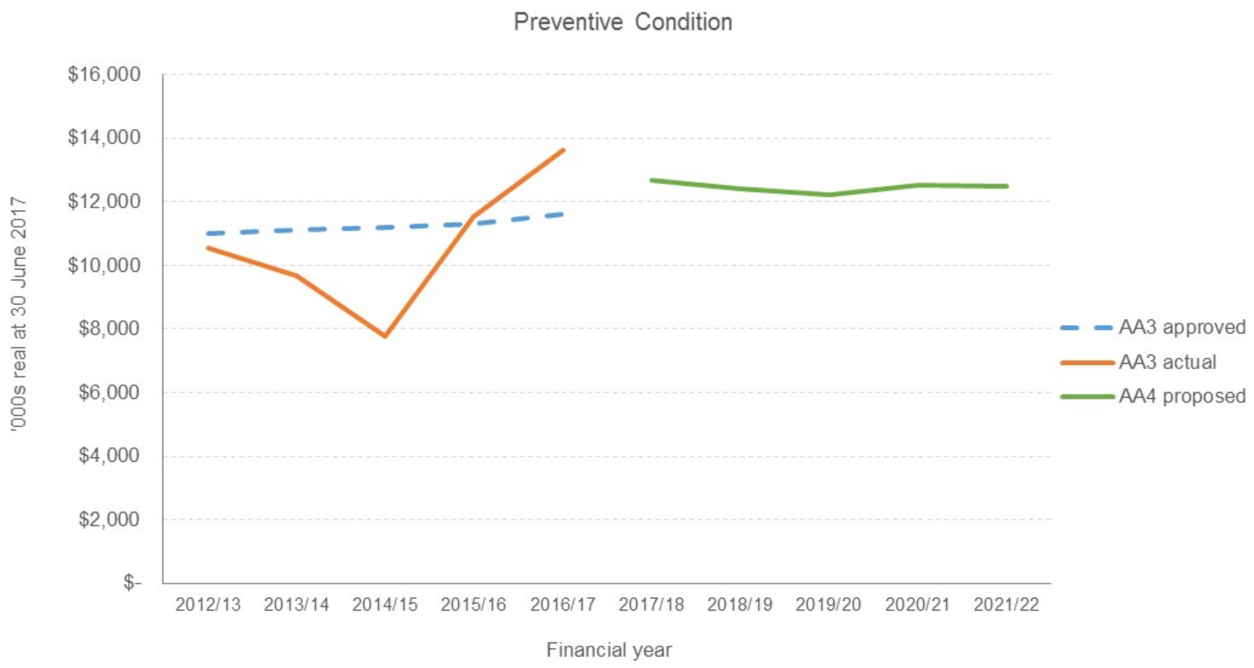
Repairs guided by condition assessments carried out during inspections focus on preventing asset failures that result in safety and reliability issues. For transmission overhead lines, these repairs are the primary strategy to maintain network integrity.

These activities are coded as K2 by Western Power, and address asset conditions identified through inspections, reported by operations or by customers. The key elements are:

- Rectification of defects identified during preventive maintenance activities, such as:
  - Pole and/or pole top maintenance
  - Conductor damage repair
  - Insulator replacement
  - Termite treatment
- Line easement vegetation management to ensure clearance zone maintained
- Mechanical vegetation clearing and herbicides for feeder efficiency
- Correction of any defects identified through routine inspection and maintenance with transmission substation primary plant

Figure 46 shows the OPEX spend during AA3 and the forecast expenditure during AA4.

Figure 46 Preventive Condition OPEX AA3 & AA4 ($'000s real at 30 June 2017)[234]



[234] Includes indirect costs

The drivers behind the forecasted preventive condition expenditure are located in Table 90.

The primary cost drivers for AA4 are:

- IVM
- enhanced work practices

We note that there was a total underspend of $3.11 million in AA3 compared to the approved allocations, and that the proposed expenditure for AA4 is consistent with the trend for the approved AA3 expenditure. This is considered reasonable given the changes in vegetation management introduced in AA3 continuing in the AA4 period, as are the improvements and efficiencies achieved regarding work practices. We therefore consider it reasonable for the AA4 forecast expenditure to be comparable with that forecast for AA3.

Whilst there was an underspend across the AA3 period, there was an overspend in 2016/17 to catch up on a backlog of rectification work which we consider a non-recurring event.

We therefore accept the forecast allowances for AA4.

13.6.4 Corrective deferred

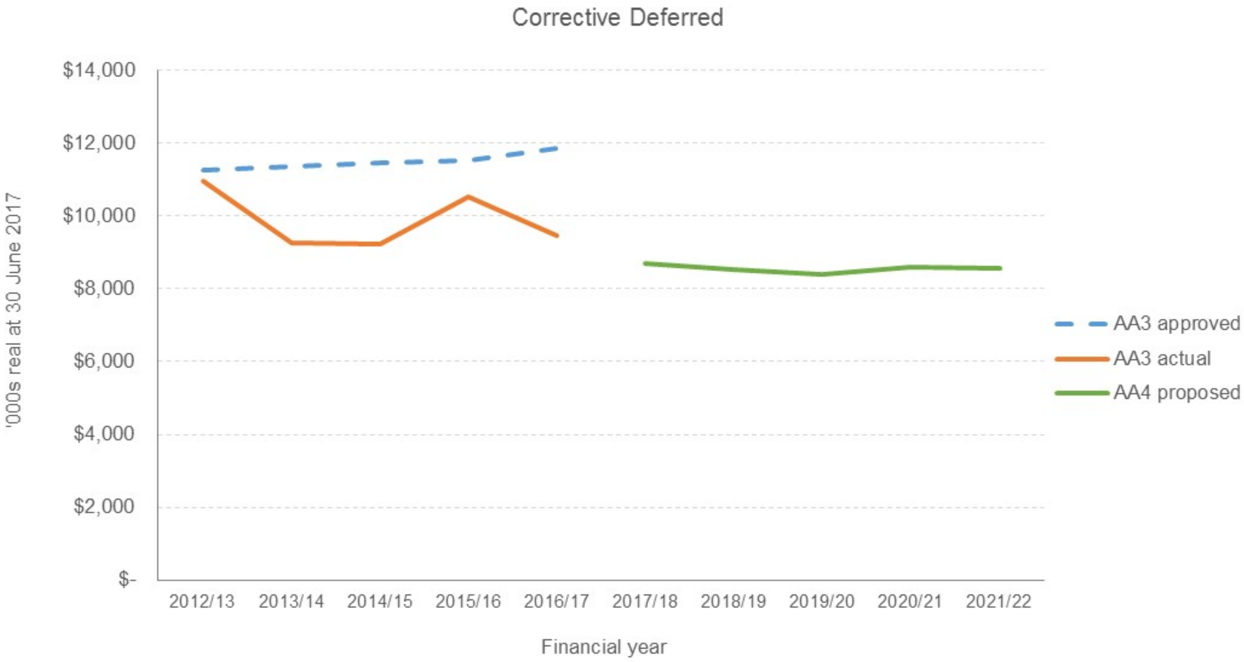
This work is coded as K3 by Western Power and relates to full repairs following temporary repairs undertaken for unplanned outages or asset failure.

The key programs are:

- emergency overhead line maintenance to address temporary network repairs
- emergency primary plant maintenance to correct any temporary repairs made to restore supply and situation safe
- emergency secondary system maintenance for temporary corrections/repairs to control & protection devices

Figure 47 shows the OPEX spend during AA3 and the forecast expenditure during AA4.

Figure 47 Corrective Deferred OPEX AA3 & AA4 ($'000s at 30 June 2017)[235]



The drivers behind the forecasted corrective deferred expenditure are located in Table 90.

Similar to distribution corrective deferred expenditure, the primary cost drivers for AA4 are:

- More efficient preventive maintenance is expected to result in fewer unplanned outages

We note that the forecast expenditure for corrective deferred is significantly less than that approved previously for AA3, and that Western Power incurred lower costs than forecast. With the work efficiencies projected by Western Power as a result of their BTP, we accept the proposed expenditure for AA4.

13.6.5 Corrective emergency

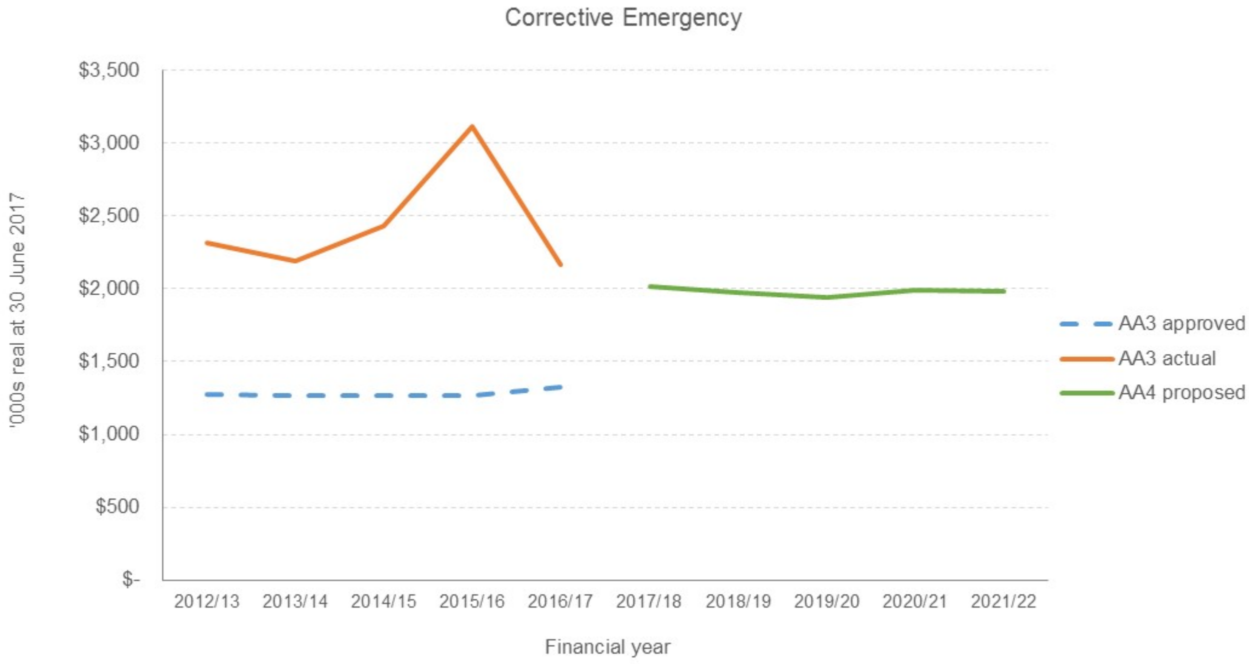
Western Power codes this work as K4, and relates to temporary repair work done to rectify an unplanned outage or asset failure to restore supply or make a situation safe. The key programs are similar to those for Corrective Deferred activities:

- emergency overhead line maintenance to make temporary network repairs
- emergency primary plant maintenance to effect any temporary repairs made to restore supply and situation safe
- emergency secondary system maintenance for temporary corrections/repairs to control & protection devices

Figure 48 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

[235] Includes indirect costs

Figure 48 Corrective Emergency OPEX AA3 & AA4 ($'000s at 30 June 2017)[236]



The drivers behind the forecasted corrective emergency expenditure are shown in Table 90.

Corrective emergency expenditure is related to the number of unplanned outages that Western Power has allowed for based on previous network performance during AA3. We note that during AA3, Western Power incurred additional expenditure, which we infer was related to a higher than expected amount of unplanned outages.

Due to the uncertain nature of forecasting expenditure for unplanned events, we consider it appropriate for the corrective emergency expenditure forecast for AA4 to be at a level similar to that incurred during the last year of AA3.

13.6.6 Operations

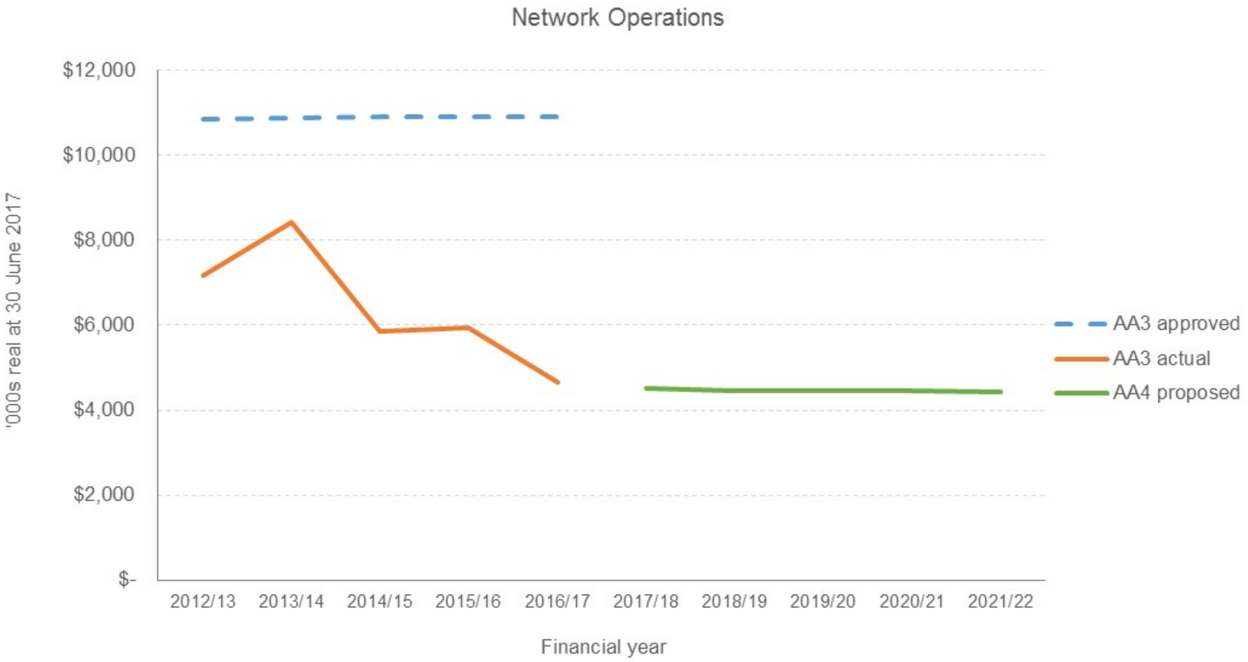
Similar to distribution, transmission Operations OPEX relates to providing communication within the Western Power Network, planning maintenance and capital works and maintaining reliability through network monitoring and network switching operations.

13.6.6.1 Network operations

Figure 49 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

[236] Includes indirect costs

Figure 49 Network operations OPEX AA3 & AA4 ($'000s at 30 June 2017)[237]



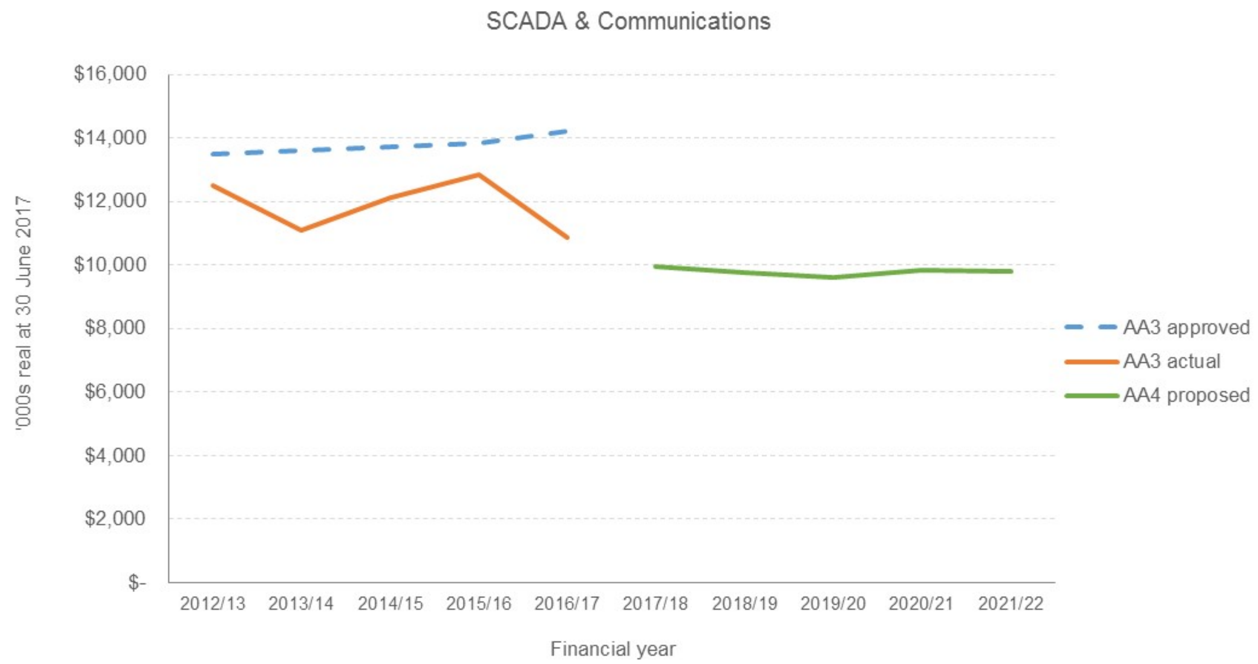
Similar to distribution Operations OPEX, as a result of the BTP during AA3 the number of FTEs that were involved in network operations was optimised. We note that the proposed expenditure for AA4 reflects the actual incurred costs in 2016/17 as the last year of the AA3 period. Therefore, we consider it reasonable for the AA4 forecast to maintain this expenditure level.

13.6.6.2 SCADA & Communications

Figure 50 shows the OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

[237] Includes indirect costs

Figure 50   SCADA & Communications OPEX AA3 & AA4 ($'000s at 30 June 2017)[238]



Similar to the distribution SCADA & Communications (refer section 13.5.6.3), there is a $52.7 million asset replacement program planned for transmission SCADA & Communications in the AA4 period (refer section 11.5.1). This expenditure compares with a value in the RAB for transmission SCADA & Communications assets of $86.9 M at the end of AA3, with an average depreciation of $8.0 M per annum.[239]

As a result, we would anticipate there would be a decrease in the corrective element of SCADA OPEX due to the lower maintenance requirements of these newer assets. In a recent benchmarking study, it was noted that *"… there appears to be a linkage between increased CAPEX investment in SCADA and Comms and a lower OPEX among transmission operators."*[240] The study also noted that Western Power had higher than average SCADA OPEX per circuit kilometre than other transmission operators, in part due to the highly reactive asset strategy Western Power had to their SCADA & Communications assets. One participant in the syudy reported high CAPEX and low OPEX, satisfied that the high levels of investment matched their strategy to invest heavily in SCADA assets to improve overall operational performance. The same utility reports low OPEX compared to other industry participants in 2017.

We do not accept that it is reasonable to maintain OPEX expenditure at similar levels to the base year during AA4. There should be a trade-off between the CAPEX and the reasonable expectation that there will less operational support required for the new equipment.

Without additional information available regarding operational costs for SCADA & Communications assets, we recommend a nominal 50% reduction, based on an assumption that the asset replacement program will replace at least 50% of the existing SCADA & Communications asset base.

[238] Includes indirect costs

[239] AA4 regulatory revenue model, values as at 30 June 2017

[240] GHD, *Investigation into Industry Practices for Managing SCADA and Telecommunications Infrastructure*, pp ii-iv

13.6.7 Findings

The Western Power asset strategy for transmission OPEX as shown in Table 90 identifies the primary drivers for the proposed reductions in expenditure for preventive routine, preventive condition, corrective deferred and corrective emergency for AA4 relative to both forecast and actual AA3 expenditure. Projected preventive expenditure decreases relative to AA3 actual expenditure as a result of deemed improvements in work practices and planning, and the introduction of IVM.

Based on our review of the forecast expenditure profiles for each of the transmission OPEX categories, we consider that Western Power has projected costs during AA4 for each category at or below the incurred OPEX expenditure for the base year 2016/17 and therefore we accept that the AA4 forecasts reflect the improvements in work practices that Western Power deem were achieved during AA3 and are reasonable.

However, we do not accept maintaining OPEX levels for SCADA & Communications at the base year levels for transmission asset during AA4, given the substantial asset replacement program proposed for these networks. We consider that it would reasonable to expect that there would be a CAPEX/OPEX trade-off between the new assets and their lower maintenance requirements. We have proposed a nominal 50% reduction in the OPEX forecast for SCADA & Communications.

13.7 Corporate OPEX

The following table summarises the approved and actual expenditure during AA3 and the proposed allowances for AA4 for corporate OPEX for both the distribution and transmission networks.

Table 91 Business support OPEX - total ($'000 real at 30 June 2017) [241]

Regulatory category	Expenditure	2012/13	2013/14	2014/15	2015/16	2016/17	AA3 total	2017/18	2018/19	2019/20	2020/21	2021/22	AA4 total
Corporate - distribution	AA3 approved	74,385	74,218	73,448	75,930	76,524	**374,507**						
	AA3 actual	65,079	82,957	68,930	111,529	112,981	**441,476**						
	AA4 proposed							84,531	61,614	61,171	61,281	61,885	**330,481**
Corporate - transmission	AA3 approved	44,143	44,215	44,197	45,856	46,350	**224,760**						
	AA3 actual	35,360	42,013	32,702	43,470	41,284	**194,829**						
	AA4 proposed							30,877	22,506	22,344	22,384	22,605	**120,717**
Total Corporate OPEX	AA3 approved	118,528	118,433	117,645	121,786	122,874	**599,267**						
	AA3 actual	100,439	124,970	101,632	154,999	154,265	**636,305**						
	AA4 proposed							115,408	84,120	83,515	83,665	84,490	**451,198**

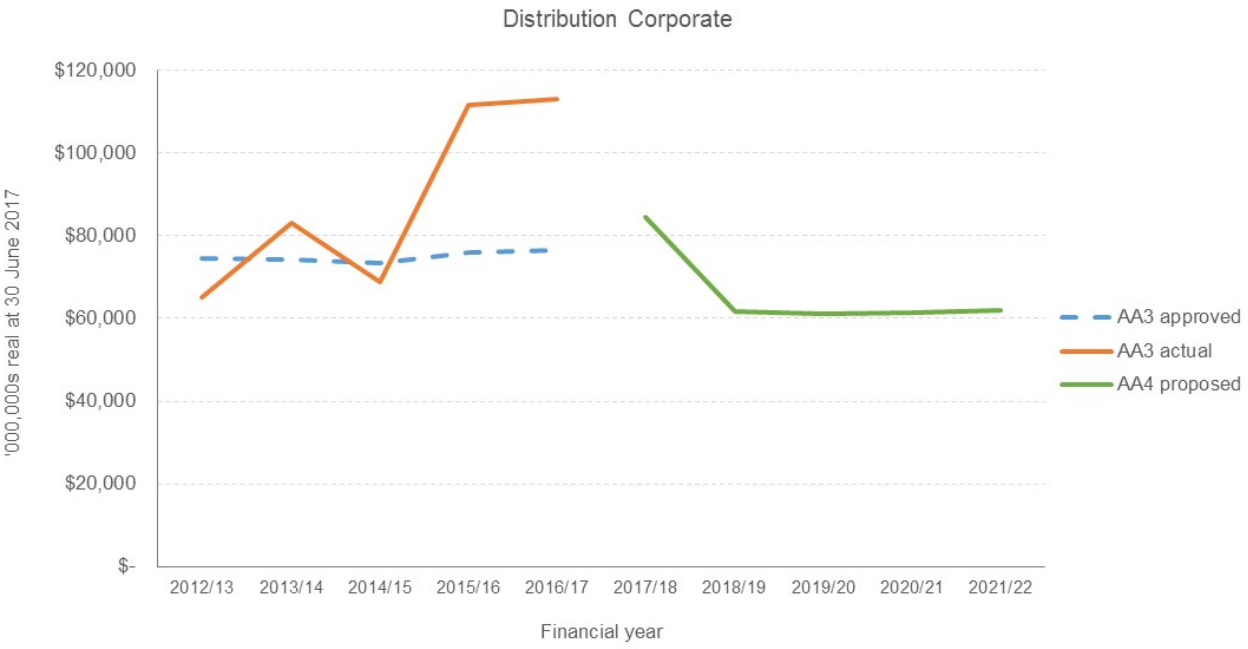
[241] Western Power Excel model *10.4 - AA4 Regulatory Revenue Model.xlsx*, worksheet *Dx_Inputs* rows 669 and 690, and worksheet Tx_Inputs rows 619 and 633

The following figures show the distribution and transmission corporate OPEX spend during AA3 and the forecast expenditure during AA4 in real FY2016/17 dollars.

A key component of corporate OPEX expenditure during AA3 was the BTP, which Western Power considers has achieved a total of $330 million in recurring savings. The BTP is expected to finish in 2017/18. Western Power has indicated that the business transformation for the corporate parts of the business has lagged the distribution and transmission parts of the business. This was a deliberate strategy on the part of Western Power to ensure that the corporate functions including business support to the network part of the business were maintained during the changes resulting from the transformation process.

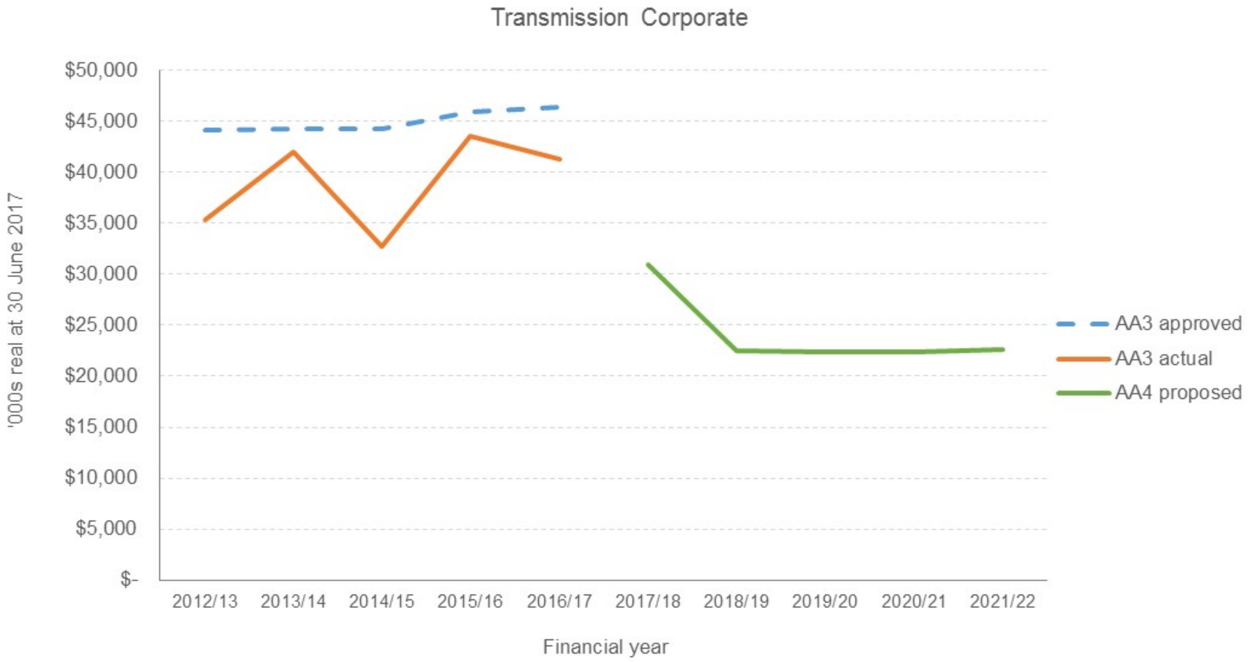
Figure 51 and Figure 52 illustrate the impact of final stage of business transformation in the corporate sector during 2017/18, and the associated reduction in ongoing corporate costs for the remainder of AA4.

Figure 51 Distribution Corporate OPEX AA3 & AA4 ($'000s at 30 June 2017)[242]



[242] Includes indirect costs

Figure 52 Transmission Corporate AA3 & AA4 ($'000s at 30 June 2017)[243]



We expect that the benefits from the BTP have established a new annual benchmark for corporate expenditure and that we consider the proposed expenditure profiles to be reasonable.

13.8 Summary

Table 92 summarises our recommended OPEX allowances for AA4.

Table 92 Recommended AA4 OPEX forecast ($'000 real at 30 June 2017)[244]

Item	Base Year	AA4 period					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
AA4 base year	317,609	317,609	317,609	317,609	317,609	317,609	1,588,045
Annual reduction		-5,000	-5,000	-5,000	-5,000	-5,000	-25,000
AA4 recurrent OPEX sub-total		*312,609*	*312,609*	*312,609*	*312,609*	*312,609*	*1,563,045*
Escalation - network growth		1,793	3,581	5,746	7,799	9,641	28,560
Efficiency dividend		-3,144	-6,292	-9,455	-12,625	-15,793	-47,310
Non-recurrent OPEX		32,533	1,183	198	-	500	34,414
Expensed indirect costs		39,993	36,676	33,183	39,175	39,256	188,283
Escalation - labour		970	1,810	2,840	4,092	5,387	15,098

243 Includes indirect costs

244 Western Power *ERA013 - AA4 operating expenditure and indirect cost model (S&C and Meter adjust).xlsx*, worksheet *BST calcs*

Item	Base Year	AA4 period					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Adjustment for maintenance for communication infrastructure from proposed AMI project [245]		-2,207	-2,214	-2,222	-2,231	-2,241	-11,117
Adjustment for SCADA & Communications as trade-off for CAPEX replacement program [246]		-7,265	-7,182	-7,116	-7,232	-7,227	-36,023
Total		**375,282**	**340,170**	**335,782**	**341,586**	**342,132**	**1,734,949**

We have recommended an alternate OPEX forecast of $1,735 million for AA4, which is $70 million or a reduction of 3.9% on the Western Power proposed total of $1,805 million.

The benchmarking review (refer section 7) concluded that for Western Power:

- in comparison with utilities in the NEM, Western Power ranked 9th for distribution utilities and 6th for transmission NSPs
- as a combined electricity network, Western Power ranked 6th (refer section 7.3.3)
- the comparable networks were SA Power Networks (distribution) and ElectraNet (transmission)
- the regulated financial statement for 2016/17 showed a transmission OPEX spend of $105.6 million and distribution of $351.1 million, totalling $456.7 million.[247]
- based on the benchmarking rankings for Western Power, the efficient range for total annual OPEX compared to a hypothetical combined SA Power Networks/ElectraNet electricity entity is between $368 million and $379 million (refer section 7.3.3)

With relatively minor scale and labour escalation during AA4, we are of the opinion that the efficient OPEX range nominated in the benchmarking review for 2016/17 can be equally applied to each of the AA4 years for comparison purposes.

From Table 92, the first year of AA4 is forecast to be $375 million, which is at the top end of the efficient range and includes allowances for the final year of the current BTP. For subsequent years in AA4, our alternate annual forecast expenditure is approximately $340 million which is below the lower end of the benchmarked efficient OPEX range.

We consider this supports the Western Power submission that they are looking to become more efficient during AA4, recognising that the first impact of many of the BTP initiatives on the total OPEX were realised in 2016/17. We believe that it is for Western Power to demonstrate it can operate at the OPEX levels recommended for AA4 to demonstrate efficiency gains it believes the BTP and other initiatives have achieved.

[245] Refer section 10.2.3.5, includes real escalation and indirect costs

[246] Refer sections 13.5.6.3 and 13.6.6.2, including real escalation and indirect costs

[247] Value includes transmission and distribution non-revenue cap services, and should not be compared with other values in this report that exclude these categories

14. Service standards

14.1 Introduction

Western Power is subject to the oversight of a number of regulatory regimes, including:

- ERA
- AEMO
- PUO

together with the WA Department of Planning, a number of workplace safety offices both State and Commonwealth, and State and federal environmental agencies.

These authorities regulate the activities of Western Power, and have the authority to impose financial and legal penalties for non-conformance with statutory requirements.

The main statutory Codes and Acts that currently govern Western Power include:

- Electricity Networks Access Code 2004 (Access Code)
- Electricity Corporations Act 2005
- Electricity Industry (Code of Conduct) Regulations 2005

Under the provisions of the Access Code, Western Power has an Access Arrangement which is approved by the ERA, and which determines the regulated revenue that may be received from electricity customers together with performance and reliability standards and performance incentives.

In accordance with the provisions of sections 13 and 14 of its transmission licence, Western Power is required to maintain and report on performance standards as requested by the ERA, and as required by the Access Code.

Chapter 11.1 of the Access Code requires Western Power to *"… 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.*"

The Access Code defines the Western Power network as that part of the SWIN that is owned by the Electricity Network Corporation (trading as Western Power).

As the Access Code states that the existing service standard benchmarks (that is, the minimum service levels that are to be achieved, known as SSBs) apply only to reference services, connections that are currently classified as non-reference service customers were excluded from the performance reporting to the ERA.

The Service Standard Adjustment Mechanism (SSAM) is the scheme by which the ERA assesses an annual financial reward or penalty for each of the measures. The annual result for each measure is calculated based on the difference between the actual performance result and the service standard target (SST), with the penalty capped at the SSB.

14.2 AA3 performance reporting

Table 93 displays the performance of measured service standards across AA3, while Table 94 displays the associated financial result.

Table 93 AA3 Service Standards Performance [248]

Performance measure			SSB	SST	2012/13 actual	2013/14 actual	2014/15 actual	2015/16 actual	2016/17 actual
Distribution	SAIDI	CBD	39.9	20.3	7.6	18.3	26.2	22.6	13.8
		Urban	183	136.6	102.7	107.4	103	91.3	104.4
		Rural Short	227.8	207.8	181.4	171.2	182.6	168.4	175.6
		Rural Long	724.8	582.2	685.4	673.8	677.5	582.6	626.2
	SAIFI	CBD	0.26	0.14	0.03	0.20	0.17	0.1	0.11
		Urban	2.12	1.36	1.16	1.13	1.09	0.91	1.02
		Rural Short	2.61	2.27	2.17	1.83	1.98	1.75	1.76
		Rural Long	4.51	4.06	4.91	4.98	4.41	3.99	3.95
	Call Centre Performance		77.50%	87.60%	90.60%	92.80%	93.70%	91.40%	91.80%
Transmission	Circuit Availability		97.70%	98.10%	98.37%	98.04%	98.53%	98.66%	98.80%
	System Minutes Interrupted	Meshed Network	12.5	N/A	4.5	4.8	6.6	6.8	8.2
		Radial Network	5	1.9	1.2	3.7	1.6	0.5	0.7
	Loss of Supply Events	>0.1 system minute interrupted	33	24	11*	17*	24	15*	16
		>1 system minute interrupted	4	2	1	1	0	1	2
	Average Outage Duration		886	698	866	795	720	1,265	653
Street Lighting Repair Time	Metropolitan area		5 days	N/A	1.23	1.14	1.26	1.55	2.47
	Regional area		9 days	N/A	2.01	1.07	1.18	0.89	4.59

[248] Western Power Service Standard Performance Report for the year ended 30 June 2017

Table 94 AA3 Service Standards Adjustment Mechanism Payments[249]

Performance measure			Penalty (-) or Reward (+)				
			2012/13	2013/14	2014/15	2015/16	2016/17
Distribution	SAIDI	CBD	$861,276	$135,634	-$400,120	-$155,979	$440,811
		Urban	$17,960,762	$15,470,627	$17,801,818	$24,000,665	$17,060,075
		Rural Short	$5,899,661	$8,179,075	$5,631,494	$8,804,797	$7,195,798
		Rural Long	-$6,730,601	-$5,974,060	-$6,215,371	-$26,088	-$2,869,636
	SAIFI	CBD	$957,891	-$522,486	-$261,243	$348,324	$261,243
		Urban	$10,979,760	$12,626,724	$14,822,676	$24,704,460	$18,665,592
		Rural Short	$2,225,110	$9,790,484	$6,452,819	$11,570,572	$11,348,061
		Rural Long	-$4,577,625	-$4,577,625	-$3,560,375	$712,075	$1,118,975
	Call Centre Performance		$1,244,850	$2,157,740	$2,531,195	$1,576,810	$1,742,790
Total Distribution Penalty/Reward			**$28,821,084**	**$34,239,948**	**$36,802,893**	**$46,645,954**	**$46,645,954**
Transmission	Circuit Availability		$2,451,558	-$408,593	$3,268,744	$4,903,116	$6,537,488
	System Minutes Interrupted – Radial Network		$73,810	-$309,670	$31,633	$147,620	$126,532
	Loss of Supply Event Frequency	>0.1 system minutes	$472,147	$254,233	$0	$326,871	$290,552
		>1 system minutes	$163,437	$163,437	$326,874	$163,437	$0
	Average Outage Duration		-$419,160	-$242,015	-$54,890	-$469,060	$156,465
Total Transmission Penalty/Reward			**$2,741,792**	**-$542,608**	**$2,906,413**	**$2,906,413**	**$2,906,413**
Total Penalty/Reward			**$31,562,876**	**$33,697,340**	**$39,709,306**	**$49,552,367**	**$49,552,367**

14.3 Assessment method

In assessing the appropriateness of the proposed parameters to be used in the SSAM, we followed the following method:

- Reviewed the system disturbance dataset to verify that it is a robust and reliable source of outage data
- Reviewed the classification of outages, including those events excluded from performance reporting
- Examined the approach used in determining the service standard targets and benchmarks; reviewing the statistical approach and any assumptions that were used

[249] Ibid. Note that totals may not add due to the floor/ceiling on penalties/rewards respectively of 1% of transmission and 5% of distribution revenue at risk

- Using the AA3 annual performance results, calculated the financial reward/penalty against the proposed AA4 framework to determine any inherent bias in the targets away from a neutral result
- Should any bias be identified, review the approach and assumptions used by Western Power and nominate a modified approach to generating service standard targets

14.4 Data reliability and accuracy

Western Power provided us with system disturbance data for average outage duration and loss of supply event frequency measures for the transmission network, and a list of excluded major event days for the distribution network.

All outages on the electricity transmission network are recorded, with the report initiated by a Network Controller and verified by Network Operations Engineering. The raw data describing the outage such as duration and date, affected network assets, magnitude of any loss of supply, voltage and frequency variations, any coincident related outages and any involvement of the Distribution Transfer Capacity (DTC).

Once an outage has been confirmed as a system disturbance, it is classified as one of the following options:

- Generation problem; where a generator trips causing the system frequency to drop below operational limits
- Fault or forced outage without interruption; where an outage occurs on a transmission network asset
- Customer problem; where an outage of a transmission network asset is attributable to failure of customer-owned plant or equipment and causes a loss of supply
- Fault or forced outage with interruption; where an outage of a transmission network asset causes a loss of supply for customer(s)
- Auto-reclosure problem; where circuit breakers automatically reclose to clear an outage on a transmission line

14.5 Excluded events

14.5.1 Non-reference service customers

Under the current regulatory framework underpinning customer connections to the Western Power network, Western Power has a number of customers who have agreed to receive services that are not consistent with a standard service arrangement.

Under section 2.7 and 2.8 of the Electricity Network Access Code 2004 (Access Code), Western Power was required to use all reasonable endeavours to accommodate an application to connect, including negotiating the contract for the requested services. This has led to multiple large transmission customer connections on the Western Power network being non-standard.

There are a four broad reasons that a connection arrangements may be for a non-standard service:

1. a requirement for above standard service including for example back-up supply and additional redundancy for increased reliability
2. below standard service at the request of the customer, for example due to the cost of the customer funded works necessary to provide a standard service
3. below standard service due to network constraints

4. below standard services due to wholesale market operations, for example under-frequency load shedding, system interruptible loads

For the purposes of service standard performance measurement under the Access Code, clause 11.1 states:

"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."

As the minimum service standard for customers with non-standard services was the subject of the agreed access contract, and not that which would apply to a reference service customer, the performance of these non-reference customers was excluded from the annual Western Power transmission network performance reporting to the ERA during AA3.

Our interest in non-reference service customers was to verify that they had been excluded from performance reporting in accordance with clause 11.1 of the Access Code. Western Power advised the following in response to our information request:

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

The dataset provided to us by Western Power identified outages that were associated with the NRS customers. We compared the annual Average Outage Duration and Loss of Supply values we generated in pivot tables from this dataset (excluding NRS customers) with the annual performance results submitted by Western Power to the ERA during AA3 and found the results to be consistent.

We are therefore satisfied that Western Power has appropriately excluded NRS customers from the annual performance results, and that the dataset we received was fit-for-purpose as the basis for target and benchmark setting for AA4.

14.5.2 Major Events Days (MEDs)

Western Power has proposed using the method outlined in the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366 to determine SSBs (known as the "2.5 beta method") with some

[250] Response to RFI GHD02 received via email 20 October 2017

modifications, to determine the MED threshold. This is consistent with the practices of electricity utilities in the NEM.

14.5.3 Kalbarri

Western Power has proposed manual adjustments to SAIFI and SAIDI measures for Rural-Long of 0.06 interruptions and 5.63 system minutes, respectively due to the proposed installation of a microgrid at Kalbarri.

We have confirmed that Western Power has correctly removed outages on the GTN-KBR feeder from performance results. Given our acceptance of the proposed micro-grid at Kalbarri (refer section 10.5.1), we agree with the Kalbarri outages being removed from consideration in setting AA4 targets and benchmarks.

14.5.4 Conclusion

We accept that Western Power has appropriately excluded non-reference service customers, MEDs and Kalbarri in the calculation of annual performance results during AA3, and as part of their analysis for calculating targets and benchmarks for AA4 measures.

14.6 Proposed AA4 service levels

14.6.1 Western Power method

Western Power has undertaken a statistical approach to setting service standard benchmarks (SSBs) and service standard targets (SSTs).

Western Power used 12-month rolling averages to generate a dataset of 60 points in lieu of using a 5-point dataset based on annual performance results. The purpose of this was to generate a larger dataset to achieve greater confidence in proposed benchmarks and targets. We assume that for measures reported in annual terms (SAIDIs & SAIFIs, loss of supply event frequencies) that the 12-month moving average for a given month is the sum of the given month's result and the preceding 11 months' results. We also assume that for average measures (call centre performance, circuit availability and average outage duration) that the 12-month moving average for a given month is the average of the previous 12 months' results, including the result from the given month.

A suite of probability distributions were fitted to the dataset, and an average of the distributions of best-fit was applied to determine the 99th (or 1st, depending on whether performance improved with a decreasing or increasing metric, respectively) percentile for benchmarks, and the 50th percentile for targets.

There were 11 continuous distributions tested. These included the Weibull, the 3-parameter Weibull and the generalised extreme value distribution, all of which are noted for their accuracy at determining probability at the tails (extreme values)[251]. The three distributions mentioned were frequently included in the average of 99th (or 1st) percentiles, especially for distribution metrics.

The approach taken by Western Power to set service standard benchmarks varies from that typically used by utilities in the NEM under the AER STPIS[252] to set cap and collar values for measures. Western Power has proposed using the 99th or 1st percentile value as the SSB, as opposed to a 97.5th or a 2.5th percentile value.

[251] Markose, S & Alentorn, A 2010, 'The Generalized Extreme Value (GEV) Distribution, Implied Tail Index and Option Pricing', *The Journal of Derivatives*, Spring 2011

[252] Service Target Performance Incentive Scheme

Feedback received from the customer preference survey suggested that customers did not want improved network reliability at a cost. As a result, Western Power has proposed lowering the minimum service level (or SSB) to avoid performance results that may trigger reliability expenditure.

For setting performance measure targets, Western Power adopted the 50th percentile average of best-fitting probability distributions, in contrast to standard practice for utilities in the NEM, where an average of 5 annual results is used to establish the target for performance measures in the AER STPIS.

14.6.2 Incentive Rates

Western Power proposed SSAM[253] penalty and reward rates for distribution measures based on the value of customer reliability (VCR) estimates from the AEMO 2014 VCR Final Report[254] adjusted for WA, while the incentive rates for the transmission measures used a proportion of revenue at risk to determine penalty and reward rates. These distribution and transmission rates are outlined in Table 95.

Table 95 Proposed SSAM incentive rates vs SST for AA4 period[255]

Segment	Service Standard	$ unit rate	Reward	Penalty
Distribution	SAIDI – CBD	per SAIDI min	$26,734	$26,734
	SAIDI – Urban		$366,800	$366,800
	SAIDI – Rural Short		$114,374	$114,374
	SAIDI – Rural Long		$41,958	$41,958
	SAIFI – CBD	per SAIFI min	$30,114	$30,114
	SAIFI – Urban		$366,867	$366,867
	SAIFI – Rural Short		$117,788	$117,788
	SAIFI – Rural Long		$65,982	$65,982
	Call centre performance	per 0.1%	-$43,061	-$9,981
Transmission	Circuit availability	per 0.1%	$421,856	$187,492
	Loss of Supply > 0.1 system minute	per LOS event	$42,186	$52,732
	Loss of Supply > 1.0 system minute	per LOS event	$140,619	$421,856
	Average outage duration	per duration minute	$1,826	$2,909

14.6.3 Nominated measures

For the distribution measures for the AA4 period, Western Power has retained the measures they reported performance for in AA3.

For the transmission measures, Western Power has proposed to remove System Minutes Interrupted (SMI) from the SSAM, which was recorded in AA3 because it was considered an inappropriate measure[256]. As the

[253] Service Standard Adjustment Mechanism

[254] AEMO, *Value of Customer Reliability Review*, September 2014

[255] Access Arrangement Information p103

[256] SKM, *Transmission Network Service Provider (TNSP) Service Standards*, March 2003, section 2.1, p. 5 SKM engaged an independent review of the performance measures proposed for the then ACCC STPIS, and System Minutes Interrupted (also known as "minutes off supply") was statistically unsound and recommended its replacement with Loss of Supply Event Frequency Index measures.

transmission penalty and reward rates are determined based on weighting the revenue at risk, Western Power has proposed to adjust the weightings by distributing the 10% weighting assigned to SMI amongst the reliability of supply measures. Thus, circuit availability (a security-of-supply measure) would be assigned a 50% weighting, consistent with AA3.

The remaining 3 transmission measures pertaining to reliability of supply are collectively assigned a 50% weighting. Western Power has proposed a revised definition of loss of supply (LOS) > 0.1 minutes to be events with system minute outages between 0.1 mins and 1.0 mins, to avoid potential double counting of an outage where an event has an outage greater than 1.0 system minutes.

14.6.4 Assessment approach

We have applied the following assessment approach to the proposed targets and benchmarks for AA4:

- We note that in contrast to previous Access Arrangements where SSTs and SSBs were determined using 5-point historic annual performance results from the previous AA period, Western Power has used a 12-month rolling average dataset for the purposes of setting SSTs and SSBs for AA4. This means that the datasets for each nominated service measure has 60 points, instead of 5, but with best-fit probability distributions that have different statistical characteristics to those used for establishing the AA3 SSAM.
- We note that Western Power has excluded events from the AA4 datasets using a similar approach to that used in AA3 performance reporting,
- Western Power has proposed SSTs which are the average performance results for AA3 based on the 12-month rolling average datasets, and proposed the 99th or 1st percentile values (as appropriate) as the SSBs
- As a first pass, we have calculated the annual and aggregate financial results for the hypothetical scenario of using AA3 performance results in a SSAM scheme based on the Western Power proposed SSTs and SSBs for AA4. Given that the AA4 targets and benchmarks have been based on AA3 performance results, we would expect to find that individual service measure results over the 5-year period, together with aggregated results for the 5-year period to be approximately $0. For each service measure returning an approximately neutral financial result over the 5-year period, we will consider the SSTs and SSBs reasonable.
- In instances where there is an apparent skew towards either a financial reward or penalty for a given service measure, we will consider the targets and/or benchmarks proposed for that service measure to be unreasonable. We will review the dataset to identify any particular characteristics that are distorting the setting of targets and/or benchmarks, and for a second pass, we will propose alternate SSTs and SSBs that return approximately neutral financial results over the 5-year period.
- In recommending SSBs, we will review the proposed AA4 SSB for each service measure against the SSB used in AA3 to ensure it is comparable, and consistent with the Western Power intention to maintain service performance during AA4 and mitigate the risk of triggering broad network investment as a compliance requirement.
- Given that Western Power is planning to maintain service performance, we will consider reasonable all proposed SSBs that are equivalent or higher than those applied during AA3.
- In instances where the proposed SSB is lower than the AA3 benchmark for a service measure, we will review the dataset to understand any underlying contributing factors and recommend an alternate value.

14.6.5 Analysis

To assess the Western Power proposed AA4 SSTs for the distribution and transmission measures, we have used the AA3 historic performance results to test the appropriateness of the targets.

Table 96 summarises the assessment of the AA3 historic performance against the Western Power proposed AA4 service standard targets, which demonstrates an inherent skew towards a reward for maintaining past performance. The major contributing year was 2015/16, which generates $28 million of the $42 million result for the distribution measures for the 5-year period.

Table 96 Projected AA4 financial result based on AA3 actual performance

Segment	Measure	Unit	Proposed AA4 framework				2012/13		2013/14		2014/15		2015/16		2016/17		Result for AA3 SSAs
			Reward	Penalty	SSB	SST	SSA	Result	SSA	Result	SSA	Result	SSA	Result	SSA	Result	
Distribution	SAIDI - CBD	per SAIDI min	$26,734	$26,734	37.2	17.8	7.6	$272,687	18.3	-$13,367	26.2	-$224,566	22.6	-$128,323	13.8	$106,936	$13,367
	SAIDI - Urban	per SAIDI min	$366,800	$366,800	134.7	108.7	102.7	$2,200,800	107.3	$513,520	103	$2,090,760	91.3	$6,382,320	104.4	$1,577,240	$12,764,640
	SAIDI - Rural Short	per SAIDI min	$114,374	$114,374	226.3	190.4	181.4	$1,029,366	171.1	$2,207,418	182.6	$892,117	168.4	$2,516,228	175.6	$1,692,735	$8,337,865
	SAIDI - Rural Long	per SAIDI min	$41,958	$41,958	902.9	675.6	685.4	-$411,188	672.7	$121,678	677.5	-$79,720	582.6	$3,902,094	626.2	$2,072,725	$5,605,589
	SAIFI - CBD	per 0.01 SAIFI event	$30,114	$30,114	0.23	0.14	0.03	$331,254	0.2	-$180,684	0.17	-$90,342	0.1	$120,456	0.11	$903	$181,587
	SAIFI - Urban	per 0.01 SAIFI event	$366,867	$366,867	1.33	1.12	1.16	-$1,467,468	1.13	-$366,867	1.09	$1,100,601	0.91	$7,704,207	1.02	$36,687	$7,007,160
	SAIFI - Rural Short	per 0.01 SAIFI event	$117,788	$117,788	2.38	2.01	2.17	-$1,884,608	1.83	$2,120,184	1.98	$353,364	1.75	$3,062,488	1.76	$29,447	$3,680,875
	SAIFI - Rural Long	per 0.01 SAIFI event	$65,982	$65,982	5.9	4.67	4.91	$1,055,712	4.98	-$2,045,442	4.41	$1,715,532	3.99	$4,486,776	3.95	$47,507	$5,260,085
	Call centre performance	per 0.1%	-$43,061	-$9,981	85.3%	92.2%	90.6%	-$159,696	92.8%	$258,366	93.7%	$645,915	91.4%	-$79,848	91.8%	-$172	$664,565
	Sub-total							**$966,858**		**$2,614,806**		**$6,403,661**		**$27,966,398**		**$5,564,008**	**$43,515,732**

Segment	Measure	Unit	Proposed AA4 framework				2012/13		2013/14		2014/15		2015/16		2016/17		Result for AA3 SSAs
			Reward	Penalty	SSB	SST	SSA	Result	SSA	Result	SSA	Result	SSA	Result	SSA	Result	
Transmission	Circuit availability	per 0.1%	-$901,021	-$450,510	97.6%	98.5%	98.4%	-$187,492	98.0%	-$937,460	98.5%	$-	98.7%	$843,712	98.9%	$750	-$280,490
	Loss of Supply > 0.1 mins	per LOS event	$ 40,045	$ 30,035	27.0	17.0	13	$168,744	20	-$158,196	27	-$527,320	17	$-	16	$42,186	-$474,586
	Loss of Supply > 1.0 mins	per LOS event	$180,204	$180,204	4.0	1.0	2	-$421,856	1	$-	0	$140,619	1	$-	2	-$421,856	-$703,093
	Average outage duration	per duration min	$ 3,834	$ 2,751	1333.0	871.0	866	$9,130	795	$138,776	720	$275,726	1265	-$1,146,146	653	$398,068	-$324,446
	Sub-total							**-$431,474**		**-$956,880**		**-$110,975**		**-$302,434**		**$19,148**	**-$1,782,615**
	Total							**$535,384**		**$1,657,926**		**$6,292,686**		**$27,663,964**		**$5,583,156**	**$41,733,117**

In using a 12-month rolling average approach, Western Power has used data from FY2012 to obtain the moving average numbers for FY2013, despite this year not being included in AA3. Similarly, the data point for June 2017 (the last data point of FY2017) is only included in the moving average numbers once, despite being the most recent data point. Furthermore, FY2012 data is weighted as heavily as FY2017 data in the Western Power method. This also has an effect of removing noise from the data.

A core assumption was that the mean of the service standards performance metrics was constant over AA3; however, Western Power has stated that "*… over the course of the AA3 period, [we] achieved improvements in the majority of [our] service performance measures."*[257] (Refer to Appendix B for graphical representations of service standards metrics performance over AA3)

The aim of Western Power for the AA4 period is to maintain the level of service achieved in AA3. The proposed SSTs for distribution (based on SAIDI and SAIFI figures) are at a higher level than the average annual performance of AA3. If Western Power were to achieve their average annual performance from AA3 under the AA4 scheme as proposed by Western Power, they would receive a bonus of $5.2 million.

As a second pass at SST analysis, we calculated targets by taking the arithmetic average of the five annual performance results in AA3 for each service standards metric, similar to the target-setting method used by utilities in the NEM under the AER STPIS. To check the validity of these alternate targets, we applied the AA3 actual results to this alternate AA4 target scheme and determined the associated reward or penalty. The targets used and the financial performance of AA3 results in the alternate AA4 framework are found in Table 97.

Given that FY2015/16 represented performance well above average, we also replicated this analysis excluding FY2015/16 results and used the average of the four remaining annual service standard metric performances as the AA4 SSTs. This analysis can be found in Table 98.

In analysing targets based on AA3 average performance, we have included the manual adjustments to SAIFI and SAIDI measures for Rural Long as proposed by Western Power (being 0.06 interruptions and 5.63 system minutes, respectively) due to the proposed installation of a microgrid at Kalbarri (refer section 10.5.1).

[257] Western Power, *Access Arrangement Information for the AA4 period*, p. 89

Table 97 Projected financial result using annual average AA3 performance as targets

Segment	Measure	Unit	Proposed AA4 framework				2012/13		2013/14		2014/15		2015/16		2016/17		Result for AA3 SSAs
			Reward	Penalty	SSB	SST	SSA	Result	SSA	Result	SSA	Result	SSA	Result	SSA	Result	
Distribution	SAIDI - CBD	per SAIDI min	$26,734	$26,734	37.2	17.7	7.6	$270,013	18.3	-$16,040	26.2	-$227,239	22.6	-$130,997	13.8	$104,263	-$0
	SAIDI - Urban	per SAIDI min	$366,800	$366,800	134.7	101.7	102.7	-$352,128	107.3	-$2,039,408	103	-$462,168	91.3	$3,829,392	104.4	-$975,688	$0
	SAIDI - Rural Short	per SAIDI min	$114,374	$114,374	226.3	175.8	181.4	-$638,207	171.1	$539,845	182.6	-$775,456	168.4	$848,655	175.6	$25,162	-$0
	SAIDI - Rural Long	per SAIDI min	$41,958	$41,958	902.9	643.3	685.4	-$1,768,530	672.7	-$1,235,663	677.5	-$1,437,062	582.6	$2,544,753	626.2	$715,384	-$1,181,118
	SAIFI - CBD	per 0.01 SAIFI event	$30,114	$30,114	0.23	0.12	0.03	$277,049	0.2	-$234,889	0.17	-$144,547	0.1	$66,251	0.11	$36,137	-$0
	SAIFI - Urban	per 0.01 SAIFI event	$366,867	$366,867	1.33	1.06	1.16	-$3,595,297	1.13	-$2,494,696	1.09	-$1,027,228	0.91	$5,576,378	1.02	$1,540,841	$0
	SAIFI - Rural Short	per 0.01 SAIFI event	$117,788	$117,788	2.38	1.90	2.17	-$3,203,834	1.83	$800,958	1.98	-$965,862	1.75	$1,743,262	1.76	$1,625,474	$0
	SAIFI - Rural Long	per 0.01 SAIFI event	$65,982	$65,982	5.90	4.39	4.91	-$3,444,260	4.98	-$3,906,134	4.41	-$145,160	3.99	$2,626,084	3.95	$2,890,012	-$1,979,460
	Call centre performance	per 0.1%	-$43,061	-$9,981	85.3%	92.1%	90.6%	-$628,691	92.8%	$73,859	93.7%	$163,688	91.4%	-$284,203	91.8%	-$111,959	-$787,304
	Sub-total							**-$13,083,884**		**-$8,512,168**		**-$5,021,033**		**$16,819,576**		**$5,849,626**	**-$3,947,882**

Segment	Measure	Unit	Proposed AA4 framework				2012/13		2013/14		2014/15		2015/16		2016/17		Result for AA3 SSAs
			Reward	Penalty	SSB	SST	SSA	Result	SSA	Result	SSA	Result	SSA	Result	SSA	Result	
Transmission	Circuit availability	per 0.1%	-$901,021	-$450,510	97.6%	98.5%	98.4%	-$901,021	98.0%	-$4,505,105	98.5%	$0	98.7%	$901,020	98.9%	$1,802,040	-$2,703,066
	Loss of Supply > 0.1 mins	per LOS event	$40,045	$30,035	27.0	18.6	13	$224,252	20	-$42,049	27	-$252,294	17	$64,072	16	$104,117	$98,098
	Loss of Supply > 1.0 mins	per LOS event	$180,204	$180,204	4.0	1.2	2	-$144,163	1	$36,041	0	$216,245	1	$36,041	2	-$144,163	$0
	Average outage duration	per duration min	$3,834	$2,751	1333.0	859.8	866	-$17,056	795	$248,443	720	$535,993	1265	-$1,114,705	653	$792,871	$445,546
	Sub-total							**-$837,988**		**-$3,374,849**		**$499,944**		**-$113,572**		**$2,554,865**	**-$2,159,422**
	Total							**-$13,921,872**		**-$11,887,017**		**-$4,521,089**		**$16,706,003**		**$8,404,491**	**-$6,107,304**

Table 98 Projected financial result using annual average AA3 performance (excluding FY2015/16)

Segment	Measure	Unit	Proposed AA4 framework				2012/13		2013/14		2014/15		2015/16		2016/17		Result for AA3 SSAs
			Reward	Penalty	SSB	SST	SSA	Result	SSA	Result	SSA	Result	SSA	Result	SSA	Result	
Distribution	SAIDI - CBD	per SAIDI min	$26,734	$26,734	37.2	16.5	7.6	$237,264	18.3	-$48,790	26.2	-$259,988	22.6	-$163,746	13.8	$71,513	-$163,746
	SAIDI - Urban	per SAIDI min	$366,800	$366,800	134.7	104.4	102.7	$605,220	107.3	-$1,082,060	103	$495,180	91.3	$4,786,740	104.4	-$18,340	$4,786,740
	SAIDI - Rural Short	per SAIDI min	$114,374	$114,374	226.3	177.7	181.4	-$426,043	171.1	$752,009	182.6	-$563,292	168.4	$1,060,819	175.6	$237,326	$1,060,819
	SAIDI - Rural Long	per SAIDI min	$41,958	$41,958	902.9	659.8	685.4	-$1,073,286	672.7	-$540,419	677.5	-$741,817	582.6	$3,239,997	626.2	$1,410,628	$2,295,103
	SAIFI - CBD	per 0.01 SAIFI event	$30,114	$30,114	0.23	0.13	0.03	$293,612	0.2	-$218,327	0.17	-$127,985	0.1	$82,814	0.11	$52,700	$82,813
	SAIFI - Urban	per 0.01 SAIFI event	$366,867	$366,867	1.33	1.10	1.16	-$2,201,202	1.13	-$1,100,601	1.09	$366,867	0.91	$6,970,473	1.02	$2,934,936	$6,970,473
	SAIFI - Rural Short	per 0.01 SAIFI event	$117,788	$117,788	2.38	1.94	2.17	-$2,768,018	1.83	$1,236,774	1.98	-$530,046	1.75	$2,179,078	1.76	$2,061,290	$2,179,078
	SAIFI - Rural Long	per 0.01 SAIFI event	$65,982	$65,982	5.90	4.50	4.91	-$2,688,767	4.98	-$3,150,641	4.41	$610,334	3.99	$3,381,578	3.95	$3,645,506	$1,798,010
	Call centre performance	per 0.1%	-$43,061	-$9,981	85.3%	92.2%	90.6%	-$699,741	92.8%	$57,391	93.7%	$147,220	91.4%	-$355,253	91.8%	-$183,009	-$1,033,393
	Sub-total							**-$8,720,961**		**-$4,094,663**		**-$603,528**		**$21,182,499**		**$10,212,549**	**$17,975,896**

Segment	Measure	Unit	Proposed AA4 framework				2012/13		2013/14		2014/15		2015/16		2016/17		Result for AA3 SSAs
			Reward	Penalty	SSB	SST	SSA	Result	SSA	Result	SSA	Result	SSA	Result	SSA	Result	
Transmission	Circuit availability	per 0.1%	-$901,021	-$450,510	97.6%	98.5%	98.4%	-$450,510	98.00%	-$937,460	98.50%	$-	98.70%	$843,712	98.90%	$750	-$543,508
	Loss of Supply > 0.1 mins	per LOS event	$40,045	$30,035	27.0	19.0	13	$240,270	20	-$158,196	27	-$527,320	17	$-	16	$42,186	-$403,060
	Loss of Supply > 1.0 mins	per LOS event	$180,204	$180,204	4.0	1.3	2	-$135,153	1	$-	0	$140,619	1	$-	2	-$421,856	-$416,390
	Average outage duration	per duration min	$3,834	$2,751	1333.0	758.5	866	-$295,733	795	$138,776	720	$275,726	1265	-$1,146,146	653	$398,068	-$629,309
	Sub-total							**-$641,126**		**-$956,880**		**-$110,975**		**-$302,434**		**$19,148**	**-$1,992,267**
	Total							**-$9,362,087**		**-$5,051,543**		**-$714,503**		**$20,880,065**		**$10,231,697**	**$15,983,629**

The result of using the arithmetic average of five years of data was a net penalty of approximately $6 million over AA4, while using the average of the four non-anomalous years of data produced a $16 M bonus ($18 M from distribution, and -$2 M from transmission) over AA4.

14.6.6 Recommendations

14.6.6.1 Service Standard Measures

We agree with the selected SAIDI and SAIFI measures, which are consistent with those used historically in the SSAM, as they provide a good indication of network performance.

We agree with the use of the call centre performance measure and we believe the proposed target reasonable for AA4.

We agree with Western Power that System Minutes Interrupted is an inappropriate measure and should be removed from the SSAM. We also agree that the weightings for revenue at risk to determine incentive and penalty rates need to be modified given the removal of SMI, and that the weightings chosen are reasonable. We agree with the revised definition of LOS > 0.1 minutes to be > 0.1 mins and < 1.0 mins, as this is more definitive.

14.6.6.2 Service Standard Targets

We commend Western Power for their analytical approach to setting benchmark and target service standards. We accept that the 12-month rolling average approach adopted by Western Power generated a dataset of 60 points, which lead to more statistically significant results. However, it had the effect of removing the month-on-month “noise” inherent in the AA3 performance results, and effectively weighted historic performance against recent performance for measures where year-on-year performance results were either relatively consistent or steadily improving (as for most of the distribution SAIDI and SAIFI measures).

As a result, the targets generated through the statistical analysis of the 60-point datasets generated SSTs that resulted in projected material bonus payments in AA4 should AA3 performance levels be maintained (refer Table 96) in line with the Western Power stated aim. To generate targets that provide for a more neutral result, as a second pass on the dataset for the distribution measures to set targets, we have deferred to an approach similar to that used by the AER in establishing targets for measures within its STPIS which uses the arithmetic average of the past 5 performance results. In doing so, we have generated distribution measure targets that produce a more neutral result for AA3 performance results against the AA4 SSAM framework (refer Table 97). We accept the targets proposed by Western Power for the transmission measures.

Table 99 shows our recommended SSTs for the AA4 SSAM performance measures.

Table 99 Recommended Service Standard scheme for AA4 SSAM measures

Segment	Measure	Unit	Bonus	Penalty	Western Power SST	Recommended SST
Distribution	SAIDI – CBD	SAIDI mins	$26,734	$26,734	17.8	17.7
	SAIDI – Urban	SAIDI mins	$366,800	$366,800	108.7	101.7
	SAIDI – Rural Short	SAIDI mins	$114,374	$114,374	190.4	175.8
	SAIDI – Rural Long	SAIDI mins	$41,958	$41,958	675.6	643.3

Segment	Measure	Unit	Bonus	Penalty	Western Power SST	Recommended SST
	SAIFI – CBD	SAIFI events	$30,114	$30,114	0.14	0.12
	SAIFI – Urban	SAIFI events	$366,867	$366,867	1.12	1.06
	SAIFI – Rural Short	SAIFI events	$117,788	$117,788	2.01	1.90
	SAIFI – Rural Long	SAIFI events	$65,982	$65,982	4.67	4.39
	Call Centre Performance	%	-$43,061	-$9,981	92.2%	92.1%
Transmission	Circuit Availability	%	-$421,856	-$187,492	98.5%	98.5%
	Loss of Supply Event Frequency (>0.1 to ≤1 SMI)	Number of events	$42,186	$52,732	17.0	17.0
	Loss of Supply Event Frequency (>1 SMI)	Number of events	$140,619	$421,856	1.0	1.0
	Average Outage Duration	Minutes	$1,826	$2,909	871.0	871.0

14.6.6.3 Service Standard Benchmarks

The service standard benchmark is the minimum service level allowed for a performance measure; with non-compliance potential triggering expenditure to improve performance. We understand that it is Western Power's stated intention to maintain historic network performance levels during AA4, in line with feedback from the customer engagement program.[258]

In establishing the SSBs for AA3, Western Power adopted the 97.5th percentile value based on probability distributions that were fitted to historical data for the prior 5 years using 60 point, 12-month rolling average data sets. These SSB's represented the minimum performance levels in line with the performance requirements under the distribution and transmission licences[259] held by Western Power for operation of the SWIS.

For AA4, Western Power is proposing to maintain service performance from AA3, and consequently constrain network investment to a level that "*… aligns closely with customer satisfaction analysis, indicating that customers are satisfied with the current level of performance. As such, Western Power proposes the use of the 99th percentile for setting SSBs. With a 1% probability of exceeding each metric, the total result is a*

[258] Western Power, *Access arrangement information for AA4 period*, 2 October 2017, section 4.1.5, table 4.9, p. 44. Insight action #13 from review of customer engagement program noted that "*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 risk will also be targeted.*" [emphasis added]

[259] EDL1 (Electricity Distribution Licence) and ETL2 (Electricity Transmission Licence) under *Electricity Industry Act 2004 (WA)*

15.7% probability of exceeding at least one [service standard benchmark] *per year. The reduced probability better aligns with the goal of maintaining performance and the proposed investment.*"[260]

By using a 12-month rolling average dataset for the AA4 analysis, the probability distributions for a majority of the service measures have smaller standard deviations, making the distributions "narrower"[261]. In establishing the targets and benchmarks for AA4, Western Power has stated that its intention is to maintain performance from AA3, and avoid broad network investment to improve overall performance in line with feedback from its customers. Therefore, in setting the benchmarks (i.e. minimum service levels), we are of the opinion that Western Power was conscious to set these at a level that was comparable to the SSB values used in AA3 without necessarily adopting the same percentile (2.5th or 97.5th) as was used in AA3. Adopting the 2.5th or 97.5th percentile on the larger, "narrower" datasets would set the benchmark level relatively high and therefore increase the risk that the minimum service level is not met, consequently triggering a broad investment requirement as a compliance issue.

Table 100 shows a comparison of the SSBs used for AA3, those proposed by Western Power for AA4 and our recommendation. We have accepted the transmission values as proposed by Western Power as being reasonable, and consistent with the intent of maintaining minimum performance levels and minimising the risk of additional compliance expenditure requirements being imposed.[262]

For the distribution service measures, we have accepted the values proposed by Western Power for their CBD, Urban and Rural Short networks, as these represent an improvement in, or raising of, the minimum service level compared to AA3.

For Rural Long, we reviewed the actual monthly performance data for the period 2012/13 to 2016/17, and applied the following procedure to calculate an alternate SSB:

- Whilst we accept the Western Power plan to avoid general network compliance expenditure, we do not accept the proposed SSBs as reasonable when compared with the AA3 SSBs for Rural Long and are more characteristic of the impact of using a 12-month rolling average dataset rather than reflecting annual performances.
- In reviewing AA3 performance data, we noted that for SAIDI and SAIFI, the performance results appeared seasonal, with the worst performance occurring during the summer[263] months compared to the rest of the year.
- We have nominally excluded the top four monthly SAIDI and SAIFI results from the calculations to allow for MEDs and statistical outliers.[264]
- We have established a hypothetical worst annual performance by using the highest remaining monthly result as the average "summer" monthly result, and the average of the monthly results excluding "summer" as the average "non-summer" monthly performance.

[260] Western Power, *6.2 – Fitting Distributions for AA4 Service Standard KPIs*, 2 October 2017, section 3.3, p. 11

[261] The extent to which a probability distribution is stretched or squeezed is referred to as the dispersion. A measure of dispersion is the standard deviation, which represents the spread of the data values around the mean or average value. A low standard deviation means the data points are close to the mean; a high standard deviation means the data points are spread over a wider range of values.

[262] Access Code 2004 clause 11.1 states that "*… a service provider must provide reference services at a service standard at least equivalent to the service standard benchmarks*" and clause 11.6 discusses the penalties that may apply for a breach of the service standards

[263] "Summer" is used for the period November to February inclusive

[264] Excel model *GHD026 - Service Standards - Monthly actual service performance data*

For SAIDI, the highest monthly results excluded occurred in Jan 2017, Mar 2014, Feb 2015 and Jan 2016. The average "summer" result was the fifth highest monthly result which occurred in Jan 2013, being 127.96 mins. The average value of monthly results for months outside our nominal "summer" was 42.38 mins. Therefore, our proposed SSB = 4 * 127.96 + 8 * 42.38 = 850.9 mins

For SAIFI, the highest monthly results excluded occurred in Mar 2014, Dec 2012, Jan 2016 and Jan 2013. The average "summer" result was the fifth highest monthly result which occurred in Jan 2017, being 0.651. The average value of monthly results for months outside the nominal "summer" was 0.337. Therefore, our proposed SSB = 4 * 0.651 + 8 * 0.337 = 5.30

Table 100 shows our recommended SSB values for the AA4 service standard measures for distribution and transmission. In most instances, our recommended AA4 benchmarks are comparable to or higher than the level adopted for AA3, with the exception of our recommended alternate values for Rural Long SAIDI and SAIFI and Transmission Average Outage Duration which are volatile performance measures and consequently very sensitive to historic performance.

Table 100 Recommended Service Standard benchmarks for AA4 SSAM measures

Segment	Measure	Western Power AA3 SSB	Western Power Proposed AA4 SSB	Recommended AA4 SSB
Distribution	SAIDI – CBD	39.9	37.2	37.2
	SAIDI – Urban	183.0	134.7	134.7
	SAIDI – Rural Short	227.8	226.3	226.3
	SAIDI – Rural Long	724.8	902.9	850.9[265]
	SAIFI – CBD	0.26	0.23	0.23
	SAIFI – Urban	2.12	1.33	1.33
	SAIFI – Rural Short	2.61	2.38	2.38
	SAIFI – Rural Long	4.51	5.90	5.30[266]
	Call Centre Performance	77.5%	85.3%	85.3%
Transmission	Circuit Availability	97.7%	97.6%	97.6%
	Loss of Supply Event Frequency (>0.1 to ≤1 SMI)	33.0	27.0	27.0[267]
	Loss of Supply Event Frequency (>1 SMI)	4.0	4.0	4.0
	Average Outage Duration	886.0	1333.0	1330.0[268]

[265] Western Power, *6.2 – Fitting Distributions for AA4 Service Standard KPIs*, 2 October 2017, p. 24 As a comparison, the 97.5th percentile value was 855.7 minutes

[266] Western Power, *6.2 – Fitting Distributions for AA4 Service Standard KPIs*, 2 October 2017, p. 32 As a comparison, the 97.5th percentile value was 5.71

[267] We accept the proposed Western Power value due to the change in definition for this service measure

[268] We accept the proposed Western Power value due to the accepted change in SST in Table 99. We recognise that Average Outage Duration is a very volatile performance measure, and that the SSB and SST for this measure are very sensitive to past 5-year performance

15. Gain sharing mechanism

Western Power has submitted its access arrangement revisions for AA4 which includes the calculations for the GSM adjustment to its annual revenue requirement for AA4 (in accordance with the approved approach in AA3), together with the proposed GSM approach for AA4. The proposed approach for AA4 is identical in principle to that approved in AA3.

The Electricity Networks Access Code (the Code) provisions with respect to the GSM are set out below for convenience. Particular note should be made of the objectives for a GSM (section 6.21).

> ***'Gain sharing mechanism' defined***
>
> *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.*
>
> ***Requirement for a gain sharing mechanism***
>
> *6.20 An access arrangement must contain a GSM unless the Authority determines that a GSM is not necessary to achieve the objective in section 6.4(a)(ii).*
>
> ***Objectives for gain sharing mechanism***
>
> *6.21 A GSM must have the objective of:*
>
> *(a) achieving an equitable allocation over time between users and the service provider of innovation and efficiency gains in excess of efficiency and innovation benchmarks; and*
>
> *(b) being objective, transparent, easy to administer and replicable from one access arrangement to the next; and*
>
> *(c) giving the service provider an incentive to reduce costs or otherwise improve productivity in a way that is neutral in its effect on the timing of such initiatives.*
>
> *{For example, a service provider should not have an artificial incentive to defer an innovation until after an access arrangement review.}*
>
> *6.22 A GSM must be sufficiently detailed and complete to enable the Authority to apply the GSM at the next access arrangement review, including by prescribing the basis on which returns are to be determined for the purposes of section 6.23.*
>
> ***'Surplus' defined***
>
> *6.23 A "surplus" has arisen to the extent that:*
>
> *(a) returns actually achieved by the service provider from the sale of covered services during the previous access arrangement period;*
>
> *exceeded:*
>
> *(b) the level of returns from the sale of covered services which at the start of the access arrangement period was forecast to occur during the access arrangement period.*

Prior surpluses may be retained

6.24 Subject to the provisions of any investment adjustment mechanism, the service provider may retain all of the surplus achieved in the previous access arrangement period, and accordingly, the Authority must not make an adjustment in order to recover the surplus achieved in the previous access arrangement period when approving the price control in a subsequent access arrangement.

Determining the above-benchmark surplus

6.25 Subject to section 6.26, the Authority must determine how much (if any) of the surplus results from efficiency gains or innovation by the service provider in excess of the efficiency and innovation benchmarks in the previous access arrangement ("above-benchmark surplus").

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.

{Note: Section 11.1 requires a service provider to maintain a service standard at least equivalent to the service standard benchmarks set out in the access arrangement or access contract.}

Determining the increase to the target revenue

6.27 The Authority must apply the GSM to determine how much (if anything) is to be added to the target revenue for one or more coming access arrangement periods under section 6.4(a)(ii) in order to enable the service provider to continue to share in the benefits of the efficiency gains or innovations which gave rise to the surplus.

6.28 If the Authority makes a determination under section 6.27 to add an amount to the target revenue in more than one access arrangement period, that determination binds the Authority when undertaking the access arrangement review at the beginning of each such access arrangement period.

15.1 Access Code provisions

At a high level the best outcome for users of the network is for the service provider to have a level of OPEX that is:

- Efficient; and
- sustainable,

and that facilitates the appropriate/required standard of network performance for users.

The Code provides the framework for incentive regulation that should encourage service providers to manage their network business such that they meet the above parameters. There are three particular components of the Code provisions that should work hand in hand to encourage this desired outcome. Incentives can be within the access arrangement period (within-period) and also into future access arrangement periods (future-period).

1. Clause 6.24 of the Code allows for the service provider to retain any savings it makes within an access arrangement period. This provides certainty for the service provider and should serve to incentivise the service provider to bring forward savings as much as possible.
2. Clauses 6.19 to 6.28 provide for a GSM that enhances the incentive to make within-period savings by allowing those savings to be retained (in this case) through the following access arrangement period. It

is noted that under clause 6.21(c) any incentive mechanism should be neutral in its outcome with respect to timing of savings.

3. Clauses 6.27 and 6.28 requires that the approved network performance, or service level, must be achieved for the GSM to apply. In-period savings are not subject to this condition.

In a perfect world all incentives would work synergistically to achieve the best outcome. It is important that these Code provisions encourage a sustainable level of OPEX. The requirement to meet approved service standards for the future-period incentive to apply should do this. Note that any deterioration in network performance resulting from the NSP underspending a sustainable level of OPEX is likely to be delayed, potentially by a number of years. Thus a sustainable level of expenditure is more likely to be revealed over a period of time. It would be expected that a NSP working to continuously improve its performance is more likely to achieve a sustainable level of OPEX than one in which step cost reductions are achieved by taking costs out of the business such as through staff number reductions. The impact on network performance of such "step change" reductions in costs may not become apparent for some time.

15.2 Western Power's compliance with its AA3 proposal

The provisions with respect to the GSM in Western Power's approved access arrangement are set out below for convenience.

7.4 Gain sharing mechanism and efficiency and innovation benchmarks

7.4.1 In accordance with sections 5.25 and 6.20 of the Code, a GSM and efficiency and innovation benchmarks will apply with respect to this access arrangement.

7.4.2 Subject to section 7.4.3 of this access arrangement, an above-benchmark surplus (within the meaning of the Code) is to be calculated for each of the years 2012/13 to 2016/17 as follows:

$ABS_{2012/13} = EIB_{2012/13} - A_{2012/13}$

$ABS_{2013/14} = (EIB_{2013/14} - A_{2013/14}) - (EIB_{2012/13} - A_{2012/13})$

$ABS_{2014/15} = (EIB_{2014/15} - A_{2014/15}) - (EIB_{2013/14} - A_{2013/14})$

$ABS_{2015/16} = (EIB_{2015/16} - A_{2015/16}) - (EIB_{2014/15} - A_{2014/15})$

$ABS_{2016/17} = (EIB_{2016/17} - A_{2016/17}) - (EIB_{2015/16} - A_{2015/16})$

where:

***ABSt** is the above-benchmark surplus in year t;*

***EIBt** is the efficiency and innovation benchmark for financial year t as set out in Table 33, adjusted for:*

a) any difference between the actual scale escalation factors in each financial year and the forecast scale escalation factors used to establish the non-capital costs component of approved total costs for that financial year, in accordance with section 7.4.8 of this access arrangement. The scale escalation factors are a customer growth rate based on growth in customer numbers and a network growth rate based on increases in line length, increases in substation capacity and increases in the number of distribution transformers; and

b) the effects of inflation.

Table 33: Efficiency and innovation benchmarks ($M real as at 30 June 2012)

Financial year ending:	*30 June 2013*	*30 June 2014*	*30 June 2015*	*30 June 2016*	*30 June 2017*
Efficiency and innovation benchmark - EIBt	*444.4*	*446.6*	*443.0*	*440.6*	*452.0*

and

***At** is the sum of the actual non-capital costs incurred by Western Power for the transmission system and distribution system in year t, excluding any amount of non-capital costs incurred by Western Power:*

i. in accordance with the D-factor scheme in this access arrangement and providing that the expenditure has been approved by the Authority

ii. in accordance with any adjustment made under section 7.1 of this access arrangement

iii. in accordance with any adjustment made under section 7.2 of this access arrangement

iv. in relation to superannuation for defined benefits schemes

v. in relation to non-revenue cap services

vi. in relation to licence fees

vii. in relation to the energy safety levy

viii. in relation to network control services

ix. in relation to amounts payable under the Economic Regulation Authority (Electricity Network Access Funding Regulations) 2012

7.4.3 In any year in which an above-benchmark surplus is calculated to be a positive value the above-benchmark surplus does not exist to the extent that Western Power achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks during this access arrangement period by failing to provide reference services at a service standard at least equivalent to the service standard benchmarks for that year as set out in section 4 of this access arrangement.

7.4.4 If in any year in which an above-benchmark surplus is calculated to be a positive value and Western Power fails to provide a reference service at a service standard at least equivalent to the service standard benchmark, Western Power will demonstrate to the Authority how and to what extent there is, or is not, a relationship between that failure and Western Power's achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks, through consideration of:

a) which service standard benchmark has not been met in that year;

b) an analysis of the causes for not meeting the service standard benchmark in that year;

c) the categories of non-capital costs that impact on the achievement of that service standard benchmark (which may be sub-categories of the cost categories in section 7.4.8);

d) after normalising the forecast non-capital costs for those categories in section 7.4.4c) used to establish the non-capital costs component of approved total costs for inflation (using the CPI) and scale escalation factors in a manner that is consistent with 7.4.8, whether there has, or has not, been an underspend in those non-capital costs categories; and

e) any other issues that are relevant.

This information will be used to determine the extent, if any, that Western Power achieved efficiency gains or innovation in excess of the efficiency and innovation benchmarks during this access arrangement period by failing to provide reference services at a service standard at least equivalent to the service standard benchmarks.

7.4.5 Subject to section 7.4.6 of this access arrangement, the following amounts GSMAt will be added to target revenue for one or more access arrangement periods covering the years 2017/18 to 2021/22:

$GSMA_{2017/18} = ABS_{2012/13} + ABS_{2013/14} + ABS_{2014/15} + ABS_{2015/16} + ABS_{2016/17}$

$GSMA_{2018/19} = ABS_{2013/14} + ABS_{2014/15} + ABS_{2015/16} + ABS_{2016/17}$

$GSMA_{2019/20} = ABS_{2014/15} + ABS_{2015/16} + ABS_{2016/17}$

$GSMA_{2020/21} = ABS_{2015/16} + ABS_{2016/17}$

$GSMA_{2021/22} = ABS_{2016/17}$

where:

GSMAt is the GSM adjustment to target revenue for year t.

7.4.6 In any year where the amount of an adjustment to target revenue determined under section 7.4.5 of this access arrangement is a negative value, the amount of the adjustment to target revenue in that year is zero.

7.4.7 The GSM does not affect the ordinary operation of the transmission system and distribution system revenue caps (absent the GSM), which already provides for Western Power to retain 100% of any efficiency gains achieved during this access arrangement period. This characteristic is consistent with section 6.24 of the Code which ensures that Western Power can retain all of the surplus achieved in this access arrangement period.

7.4.8 The adjustment to EIBt due to any differences between the actual scale escalation factors in each financial year and the forecast scale escalation factors used to establish the non-capital costs component of approved total costs for that financial year will be calculated by:

a) deflating EIBt for financial year t by using:

> *i. the scale escalation factors assumed for financial year t when setting the forecast non-capital cost component of approved total costs for that financial year, compounded to that financial year, as set out in Table 34;*
>
> *ii. the applicable scale escalation factor for financial year t determined for each category of expenditure as set out in Table 35; and*

b) inflating the value determined under section 7.4.8a) for financial year t using:

> *i. the scale escalation factors recalculated for financial year t using actual data for each scale escalation driver in each financial year, compounded to that financial year, and following the calculation method set out in Table 34;*
>
> *ii. the applicable scale escalation factor for financial year t determined for each category of expenditure as set out in Table 35.*

Table 34: Forecast scale escalation assumptions

Scale escalation driver	Calculation method	2011/12	2012/13	2012/14	2014/15	2015/16	2016/17
Customer Numbers factor	Year on year growth	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%
Total line length (a)	Year on year growth	1.31%	1.31%	1.31%	1.31%	1.31%	1.31%
Distribution transformers (b)	Year on year growth	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%
Zone substation capacity (c)	Year on year growth	3.65%	3.65%	3.65%	3.65%	3.65%	3.65%
Network growth factor	Average of a, b and c	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%

Table 35: Scale escalation factor for each category of expenditure

Cost category	Scale escalation factor
Transmission	
Operations	
SCADA & Communications	Network growth factor * 95%
Non-revenue cap services	N/A
Network Operations	Network growth factor * 30%
Maintenance	
Maintenance Strategy	N/A
Preventive Condition	Network growth factor * 95%
Preventive Routine	Network growth factor * 95%
Corrective Deferred	Network growth factor * 95%
Corrective Emergency	Network growth factor * 95%
Customer service and billing	
N/A	N/A
Corporate	
Business Support	N/A
Other	
Non-recurring Opex	N/A
Distribution	
Operations	
Reliability Improvement	Network growth factor * 95%
SCADA & Communications	Network growth factor * 95%
Non-revenue cap services	N/A
Network Operations	Network growth factor * 30%

Cost category	*Scale escalation factor*
Smartgrid	*N/A*
Maintenance	
Maintenance Strategy	*N/A*
Preventive Condition	*Network growth factor * 95%*
Preventive Routine	*Network growth factor * 95%*
Corrective Deferred	*Network growth factor * 95%*
Corrective Emergency	*Network growth factor * 95%*
Customer service and billing	
Call Centre	*Customer numbers factor * 95%*
Metering	*Customer numbers factor * 95%*
Guaranteed Service Level Payments	*N/A*
Distribution Quotations	*N/A*
Corporate	
Business Support	*N/A*
Other	
Non-recurring Opex	*N/A*

7.4.9 For the purposes of clause 7.4.8b)(i) the actual data used for each scale escalation driver must be independently audited. The audit must be carried out by an independent auditor approved by the Authority, with Western Power managing and funding the audit. The scope of the audit will be determined by the Authority.

Western Power has complied fully with the provisions of its current access arrangement with the exception of section 7.44 which requires Western Power to provide a detailed explanation of its performance in any year in which it achieved a positive value above-benchmark surplus but where it fails to provide a reference service at a service standard at least equivalent to the service standard benchmark. This occurred in the 2013/14 financial year. In the scheme of things this does not have a significant effect on the financial outcome of the GSM. However it suggests that Western Power may not be clear in its understanding of the link between its network performance and its non-capital expenditure (OPEX).

Western Power has correctly determined the surplus in each year of the AA3 period. Clauses 6.25 and 6.26 of the Code set out the obligations on the ERA which require the ERA to approve any surplus that has been calculated in accordance with the approved access arrangement provisions.

15.3 Compliance of Western Power GSM with Code provisions

In the discussion on the Code provisions it was noted that in-period and future-period incentives should work hand in hand to encourage an efficient and sustainable level of OPEX. The following paragraphs will demonstrate that the incentives within the GSM encourage Western Power to delay savings within-period in order to maximise the benefit in the following access arrangement period. This is contrary to clause 7.21(c) of the Code. Because of this very clear incentive to delay savings and the very high volatility of the outcome with respect to the timing of the savings, it is also unclear whether the equitable allocation of benefits, required by clause 7.21(a) of the Code, will be met.

The following sections demonstrate the impact of timing of savings on the level of benefit that Western Power can receive under the GSM.

Table 101 Case 1: Western Power actual numbers

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
(a) Efficiency and innovation benchmark EIBt	486.97	489.2	481.7	473.0	481.4	2412
(b) Actual expenditure At	489.5	485.6	457.9	482.6	420.3	2336
(c) Prior year carry-forward	0	-2.6	3.6	23.8	-9.4	
Above benchmark surplus ABSt (a-b-c)	-2.6	6.2	20.2	-33.5	70.8	61
Above benchmark surplus ABSt adjusted for service standard performance	-2.6	0	20.2	-33.5	70.8	55

Amounts to be added to the AA4 annual revenue requirement.

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
GSM for AA4 (Transmission and Distribution)	54.9	57.5	57.5	37.3	70.8	278

It can be seen that the very high surplus achieved in the final year has resulted in very high values for the GSM in each year because the final year of AA3 is included in all years of the benefit for AA4. This is a clear demonstration of the incentive to achieve savings at the end of an access arrangement period. This is contrary to the objective spelt out in section 6.21(c) of the Code. It is arguable that it also is contrary to section 6.21(a) of the Code in that it is not an equitable sharing between users and the service provider.

To demonstrate the impact of timing of savings on the benefit derived by Western Power, the following example is given. The same numbers have been used but the first and final year's actual expenditure have been transposed. Thus the total savings over AA3 are identical but timing of the savings is quite different

Table 102 Case 2: Western Power actual numbers with year 1 and 5 expenditures transposed

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
(a) Efficiency and innovation benchmark EIBt	486.97	489.2	481.7	473.0	481.4	2412
(b) Actual expenditure At	420.3	485.6	457.9	482.6	489.5	2336
(c) Prior year carry-forward		66.67	3.6	23.9	-9.6	
Above benchmark surplus ABSt (a-b-c)	66.6	-63.1	20.2	-33.5	1.5	-8.1
Above benchmark surplus ABSt adjusted for service standard performance	66.6	-63.1	20.2	-33.5	1.5	-8.1

Amounts to be added to the AA4 annual revenue requirement.

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
GSM for AA4 (Transmission and Distribution)	-8.1	-74.7	-11.64	-31.9	1.5	-124.8

In this second case Western Power has spent the same money over the AA3 period however it would have received no GSM (the GSM cannot be negative).. This is a difference of $278 million from the actual numbers achieved in AA3.

To demonstrate the impact of smoothing the savings across the same period compared to delaying savings until the latter part of an access arrangement period the following example is given. Note that the base numbers are the same and the total savings across the period are the same but the savings have been achieved evenly through the period.

Table 103 Case 3: Savings achieved more evenly across the period

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
(a) Efficiency and innovation benchmark EIBt	486.97	489.2	481.7	473.0	481.4	2412
(b) Actual expenditure At	479.28	477.77	466.46	453.95	458.54	2336
(c) Prior year carry-forward	0	7.62	11.43	15.24	19.05	
Above benchmark surplus ABSt (a-b-c)	7.62	3.81	3.81	3.81	3.81	22.9
Above benchmark surplus ABSt adjusted for service standard performance	7.62	0	3.81	3.81	3.81	22.9

Amounts to be added to the AA4 annual revenue requirement.

	2017/18	2018/19	2019/20	2020/21	2021/22	Total
GSM for AA4 (Transmission and Distribution)	19.05	11.43	11.43	7.62	3.81	53.34

Note; that in this example the total savings achieved across the AA3 period were the same ($76 million). However the aggregate GSM for AA4 reduces from $278 million to $53.3 million. In the third example the service provider has been consistent in its efforts to reduce operating costs and in fact has the same net outcome as the actual numbers achieved by Western Power but the GSM benefit would be far lower. This appears to penalise a service provider who applies a program of continuous improvement in costs as compared to a service provider who makes a step change in costs late in an access arrangement period.

In its AA4 proposal Western Power has used 2016/17 as its base year which is used as the efficient amount for its forecast level of OPEX for the AA4 period. Because of the step reduction in expenditure in the 2016/17 year and the mechanism of the GSM, the GSM will reward Western Power for the life of the AA4, irrespective of its ability to operate at the efficient base year level.

15.4 Summary

1. The Code provisions act to provide incentives to the service provider where proper management of the network business by the service provider should produce an efficient and sustainable level of OPEX. This should be to the long-term benefit of users of the network.
2. Western Power has complied with the provisions of its access arrangement in the calculation of the GSM amounts for AA4.
3. The ERA is obligated to approve the GSM amounts for AA4.

4. Western Power has not demonstrated ongoing continuous improvement in its management of its operating expenditure. Instead there has been a step reduction in expenditure in the final year of the access arrangement that coincides with a significant reduction in staff numbers.
5. It is not clear that the 2016/17 base year used to forecast OPEX across the AA4 period represents a sustainable level of expenditure for Western Power. Sustained savings across the AA3 period based on continuous improvement would have provided much greater comfort that the new base year does reflected a sustainable level of OPEX. The onus is on Western Power to demonstrate their ability to meet this level of expenditure.
6. The bias of the achieved savings to the end of AA3 has resulted in a generous benefit to Western Power that is contrary to the objectives of the GSM as set out in the Code. The particular matter is the clear benefit related to the timing of the savings rather than them being neutral to the timing. It is noted that the GSM benefit for AA4 is $278 million which largely offsets the reduction in OPEX from AA3 levels of around $60 million per annum or $300 million across AA4.
7. The fact that Western Power is accepting of the lower year (2016/17) as the base year for forecasting OPEX into future years suggests a belief that this is a level of OPEX more reflective of an efficient level of expenditure. However the current GSM mechanism did not provide sufficient incentive for Western Power management to capture these efficiencies earlier in the access arrangement period (AA3).
8. In our opinion, the ERA should not approve the GSM as set out in Western Power's AA4 submission. As previously indicated, the proposed approach does not meet the objectives of the GSM as set out in the Code. The structure of the mechanism is much less generous to a service provider undertaking a continuous improvement program than one that applies a step improvement late in an access arrangement period. This feature of the mechanism is contrary to the Code provisions which encourage an efficient and sustainable level of expenditure.
9. It may be appropriate for the ERA, in not approving the proposed GSM provisions, to request Western Power to provide a revised approach and demonstrate how that revised approach meets the objectives set out in the GSM Code provisions.

16. Summary and conclusions

The Western Power proposal for AA4 included the following provisions:

(In $ real direct costs at 30 June 2017 terms)

Distribution CAPEX	**$2,448.3 million**
Transmission CAPEX	**$784.2 million**
Corporate CAPEX	**$409.9 million**
Network OPEX	**$1,805.1 million** (including real escalation and indirect costs)

The AA4 proposal represents a $400 million reduction in total CAPEX and $584 million in OPEX from the actual expenditure incurred during AA3. In developing the AA4 proposal, Western Power has been cognisant of feedback received through its customer engagement program, using this to develop key drivers for targeted CAPEX and OPEX expenditure to optimise the risk return on expenditure whilst minimising the overall cost to the customers

The main CAPEX programs proposed for AA4 include:

- Wood pole management program
- AMI project
- Modernisation of existing depots and development of new site
- Replacement of obsolete SCADA & Communications assets

Other significant initiatives in the AA4 proposal are:

- Continuing to build on efficiency gains from the BTP through the optimisation of CAPEX and OPEX programs and projects, and corporate practices
- Upgrades to ICT systems including an upgrade to Ellipse
- Installation of a microgrid at Kalbarri to address reliability issues, and establishing a microgrid construction model that may be deployed elsewhere in the Western Power network to address similar performance issues
- Transferring of fleet to the regulated asset base

We recommend the following CAPEX and OPEX allowances for AA4.

16.1 Distribution CAPEX

Table 104 contains our recommended distribution CAPEX for AA4.

Table 104 Recommended AA4 Distribution CAPEX forecast ($M direct costs at 30 June 2017)

Distribution CAPEX	Proposed AA4 CAPEX	Alternate AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Asset replacement	1,139.4	245.1	232.1	219.4	197.1	205.4	1,099.1
Regulatory compliance	150.3	22.9	36.1	35.3	28.0	28.1	150.3
Growth	1,064.6	216.0	223.8	208.1	206.4	210.5	1,064.6
Improvement in Service	94.0	12.6	18.5	14.4	12.1	11.2	68.9
Total	**2,448.3**	**496.5**	**510.4**	**477.2**	**443.6**	**455.2**	**2,382.9**

In analysing Western Power's proposed distribution CAPEX, we have made the following recommendations:

- Amended conductor management forecast based on alternate unit rates ($8.7 million reduction in asset replacement)
- Reduced meter volumes by 23% for AMI program ($31.6 million in asset replacement)
- Disallowance of proposed incremental SCADA & Communications as part of AMI project ($25.11 million in improvement in service)

16.2 Transmission CAPEX

Table 105 contains our recommended transmission CAPEX for AA4.

Table 105 Recommended AA4 Transmission CAPEX forecast ($M direct costs at 30 June 2017)

Transmission CAPEX	Proposed AA4 CAPEX	Alternate AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Asset replacement	245.2	20.7	32.8	32.8	27.9	31.7	145.9
Regulatory compliance	155.0	16.9	23.0	19.7	17.3	18.4	95.3
Growth	294.1	43.5	44.0	35.6	48.3	41.5	212.7
Improvement in Service	89.9	11.6	19.7	22.8	20.2	15.6	89.9
Total	**784.2**	**92.6**	**119.6**	**110.7**	**113.7**	**107.2**	**543.9**

In analysing Western Power's proposed transmission CAPEX, we have made the following recommendations:

- Reduced asset replacement allowance through changes in allocations for power transformers, switchboard replacement, primary plant and protection ($99.3 million reduction in asset replacement)
- Non-acceptance of proposed substation security program as do not consider Western Power has appropriately considered what is critical infrastructure and broad interpretation of National Guidelines relating to terrorism ($59.7 million in regulatory compliance)

- Disallowance of two proposed growth projects relating to a new CBD substation at Bennet Street and a second 132 kV Picton-Busselton overhead line ($81.4 million reduction in growth)

16.3 Corporate CAPEX

Table 106 contains our recommended corporate CAPEX for AA4.

Table 106 Recommended corporate CAPEX ($M real direct costs at 30 June 2017)

Corporate	Proposed AA4 CAPEX	Alternate AA4 CAPEX					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
Business Support							
Corporate real estate	201.1	23.3	43.2	116.6	9.9	8.1	201.1
Fleet CAPEX	46.7	-	-	-	-	-	-
Fleet lease	30.4	-	-	-	-	-	-
Property, plant & equipment	4.2	0.8	0.8	0.8	0.8	0.8	4.2
Subtotal	*282.4*	*24.2*	*44.1*	*117.4*	*10.7*	*8.9*	*205.3*
IT							
Business driven	149.3	29.9	37.3	28.6	21.5	16.9	134.3
Business infrastructure	55.3	8.5	12.1	17.0	10.8	7.0	55.3
Subtotal	*204.6*	*38.4*	*49.4*	*45.7*	*32.3*	*23.9*	*189.6*
Total	**487.1**	**62.6**	**93.4**	**163.1**	**43.1**	**32.8**	**394.9**

Our recommended changes to the proposed Corporate CAPEX for AA4 are:

- disallowance of the proposed allowances for Fleet (Fleet CAPEX and Fleet lease) totalling $77 million, due to our rejection of the proposal to move Fleet into the RAB
- removal of a total of $15 million allowance for ICT associated with AMI project from IT Business Driven

16.4 OPEX

Table 107 summarises our recommended alternate OPEX forecasts for AA4.

Table 107 Recommended AA4 OPEX forecast ($'000 real at 30 June 2017) [269]

Item	Base Year	AA4 period					
		2017/18	2018/19	2019/20	2020/21	2021/22	Total
AA4 base year	317,609	317,609	317,609	317,609	317,609	317,609	1,588,045
Annual reduction		-5,000	-5,000	-5,000	-5,000	-5,000	-25,000
AA4 recurrent OPEX sub-total		*312,609*	*312,609*	*312,609*	*312,609*	*312,609*	*1,563,045*
Escalation - network growth		1,793	3,581	5,746	7,799	9,641	28,560
Efficiency dividend		-3,144	-6,292	-9,455	-12,625	-15,793	-47,310
Non-recurrent OPEX		32,533	1,183	198	-	500	34,414
Expensed indirect costs		39,993	36,676	33,183	39,175	39,256	188,283
Escalation - labour		970	1,810	2,840	4,092	5,387	15,098
Adjustment for maintenance for communication infrastructure from proposed AMI project [270]		-2,207	-2,214	-2,222	-2,231	-2,241	-11,117
Adjustment for SCADA & Communications as trade-off for CAPEX replacement program [271]		-7,265	-7,182	-7,116	-7,232	-7,227	-36,023
Total		**375,282**	**340,170**	**335,782**	**341,586**	**342,132**	**1,734,949**

We have proposed an alternate OPEX forecast of $1,735 million for AA4, which is $70 million or a reduction of 3.9% on the Western Power proposed total of $1,805 million. The drivers of this OPEX adjustment are:

- changes in scale escalation factors due to recent updates in weightings applied to AER benchmarking models ($6.1 million reduction)
- removal of scaled escalation from business support activities ($11.9 million reduction)
- transmission and distribution SCADA OPEX reduction due to SCADA & Communications CAPEX replacement programs ($36.0 million reduction)
- distribution metering OPEX reduction as a result of adjusted meter volumes due to recommended changes to AMI ($11.1 million reduction)

[269] Western Power Appendix *7.5 Western Power operating expenditure and indirect cost model.xlsx*, worksheet *Summary*

[270] Refer section 10.2.3.5, includes real escalation and indirect costs

[271] Refer sections 13.5.6.3 and 13.6.6.2, including real escalation and indirect costs

16.5 Service Standards

Table 108 displays our recommended adjustments to the SSBs and SSTs proposed by Western Power for AA4.

Table 108 Recommended Service Standard Adjustments

Segment	Measure	Unit	Bonus	Penalty	Western Power SSB	Alternate SSB	Western Power SST	Alternate SST
Distribution	SAIDI – CBD	SAIDI mins	$26,734	$26,734	37.2	37.2	17.8	17.7
	SAIDI – Urban	SAIDI mins	$366,800	$366,800	134.7	134.7	108.7	101.7
	SAIDI – Rural Short	SAIDI mins	$114,374	$114,374	226.3	226.3	190.4	175.8
	SAIDI – Rural Long	SAIDI mins	$41,958	$41,958	902.9	850.9	675.6	643.3
	SAIFI – CBD	SAIFI events	$30,114	$30,114	0.23	0.23	0.14	0.12
	SAIFI – Urban	SAIFI events	$366,867	$366,867	1.33	1.33	1.12	1.06
	SAIFI – Rural Short	SAIFI events	$117,788	$117,788	2.38	2.38	2.01	1.90
	SAIFI – Rural Long	SAIFI events	$65,982	$65,982	5.90	5.30	4.67	4.39
	Call Centre Performance	%	-$43,061	-$9,981	85.3%	85.3%	92.2%	92.1%
Transmission	Circuit Availability	%	-$421,856	-$187,492	97.6%	97.6%	98.5%	98.5%
	Loss of Supply Event Frequency (>0.1 to ≤1 SMI)	Number of events	$42,186	$52,732	27.0	27.0	17.0	17.0
	Loss of Supply Event Frequency (>1 SMI)	Number of events	$140,619	$421,856	4.0	4.0	1.0	1.0
	Average Outage Duration	Minutes	$1,826	$2,909	1,333.0	1,333.0	871.0	871.0

The drivers for adjustments in service standards include:

- Reduction in SAIDI – Rural Long SSB from 902.9 mins to 850.9 mins
- Reduction in SAIFI – Rural Long SSB from 5.90 to 5.30

- Adjustment of calculation method for SAIDI and SAIFI SSTs to the average of the performance from AA3.

16.6 Gain Sharing Mechanism

We do not consider the GSM as used by Western Power for the AA4 period to be reasonable.

Appendices

Appendix A - Kalbarri microgrid project

Kalbarri is a small community located at the northern edge of the SWIS, and is currently supplied via a 150 km 33 kV radial feeder from Geraldton substation. This feeder is considered one of the worst performing feeders in the SWIS, and is subject to several environmental factors, due to the proximity of the feeder to the Western Australian coastline.

There is an existing Synergy windfarm that currently cannot supply Kalbarri during an outage on the line due to the existing network configuration.

The primary driver for this project is reliability. The GTN-KBR feeder has been identified by Western Power as a “reliability hot spot”, with the performance on this overhead line being consistently poor in comparison with the SSAM targets for Rural Long SAIDI and SAIFI.

Table 109 shows the reported performance for the GTN-KBR feeder during AA3.

Table 109 Kalbarri feeder performance during AA3

Measure	SSB	SST	2012/13	2013/14	2014/15	2015/16	2016/17
Rural Long SAIDI	725.8	582.2	676.0	4,283.0	1,064.0	1,226.0	1,611.0
Rural Long SAIFI	4.51	4.06	7.33	17.84	4.19	7.37	7.17

It is apparent from Table 109 that the existing GTN-KBR overhead line is not achieving minimum service levels, and has been prioritised by Western Power to be addressed during AA4. In particular, Kalbarri is a community that relies heavily on the tourism industry, with the population and the associated maximum power demand changing seasonally. There has been strong community engagement with regards to potential solutions and a preference for renewable energy solutions, and Western Power is keen to pursue an option that may be used in other locations in the network with similar reliability issues.

In examining the possible solutions to providing more reliable supply to Kalbarri, Western Power considered their long-term view on network configuration, and the following possible augmentation options:

- undergrounding the existing Geraldton - Kalbarri (GTN-KBR) feeder
- replacing the existing conductor with Hendrix covered conductor
- extension of the existing Northampton feeder
- installing a microgrid based on:
    - diesel power station
    - battery energy storage system (BESS)
- increased maintenance effort on the existing GTN-KBR feeder

In evaluating the 30-year whole-of-life NPV values for these options, we applied the following assumptions:

- base case for comparison was a second 33 kV overhead line from Geraldton to Kalbarri (GTN-KBR), following a similar alignment, to provide a duplicated feed to the Kalbarri township
- undergrounding option for existing GTN-KBR feeder, following a similar alignment as existing overhead line
- battery size at Kalbarri is 2 MWh, with the primary network supply from the 1.6 MW Synergy wind farm located 25 km south of Kalbarri
- BESS option includes cost of ongoing annual maintenance for existing GTN-KBR overhead line
- based on Levelised Cost of Energy (LCoE) for wind turbines of $976/MWh and $1,116/MWH for coal-fired as included in Garnaut Review to Federal Parliament in 2011, escalated by CPI between June 2011 and June 2017
- assumed no long-term load growth for the Kalbarri community
- assumed existing distribution network within Kalbarri township will be sufficient and does not require augmentation or reinforcement
- assumed load factor of 0.25
- continuation of annual maintenance costs for existing GTN-KBR overhead line comparable with historic average of 2.5% of capital value or approximately $1 million per annum
- nominal allocation of $115,000 per annum for BESS maintenance
- nominal annual allocation of 0.80% of capital value for maintenance of 33 kV underground cable option or approximately $1.39 million pa
- NPV based on annual inflation of 2.40% and discount rate of 6.00% per annum as nominal escalation rates
- two scenarios considered - current standard asset lives for battery systems, inverters and renewable infrastructure; and nominal 15-year asset life for renewable energy assets as suggested by Western Power

We have not considered the following augmentation options:

- use of Hendrix covered conductor - not considered as a practical technical option
- extension of Northampton feeder - excluded due to known power transfer constraints

One of the sensitive variables in the analysis is the asset life assigned to the renewable assets. Current industry advice is that battery energy storage systems have an operational life of 7 years, and inverters 10 years. The 30-year analysis is sensitive to any change in these lives, as our NPV value is based on replacement of the batteries and inverters on these cycles, as there is currently no knowledge of the failure modes for these assets or any capability for these assets to remain in-service beyond their nominal lives.

We note that Western Power has assumed a 15-year life for the renewable installation.

Table 110 shows a summary of the comparative NPV values we have generated, applying the assumptions above and the two asset life options - the current industry standard lives and the nominal 15 years suggested by Western Power.

Table 110 NPV for Kalbarri supply options[272]

Option	30-year NPV based on industry std lives[273]	30-year NPV based on nominal 15-year lives[274]
Base case: construction of additional 150 km 33 kV GTN-KBR overhead line	**- $ 53.79 M**	**- $ 53.79 M**
Construction of 150 km 33 kV GTN-KBR underground cable	**- $ 201.03 M**	**- $ 201.03 M**
Installation of BESS in Kalbarri plus ongoing annual maintenance on existing 33 kV GTN-KBR overhead line	**- $ 32.53 M**	**- $ 29.29 M**

The capital estimate for the installation of the BESS and an associated switchboard and yard, together with network augmentation to provide for a direct connection to the Synergy wind farm located 25 km south of Kalbarri is $10.882 million, which is within 15% of the Western Power estimate of $9.5 million. This is within our nominal test of ±15%, and therefore the Western Power estimate is considered reasonable.

The optimal solution proposed by Western Power is the installation of a BESS, with the existing 33 kV GTN-KBR feeder retained and maintained to minimise outages, including applying silicone to pole-top insulators.

We agree that the proposed solution is a sound engineering response to the network reliability issues, and our comparative NPV analysis suggests this is the best cost option.

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[272] NPV values on CAPEX and OPEX related to options, and excludes consideration of revenue or benefits arising from options

[273] Based on industry standard asset lives - 7 years for batteries and enclosures and 10 years for inverters

[274] Refer Western Power assumption for renewable assets - batteries, enclosures and inverters

Appendix B - Service Standard Performance for AA3

The following charts show the performance for the Western Power distribution and transmission networks during AA3, measured against agreed service standards in the SSAM.

Figure 53 illustrates the performance against the SAIDI performance measures during AA3.

Figure 53 AA3 SAIDI Performance

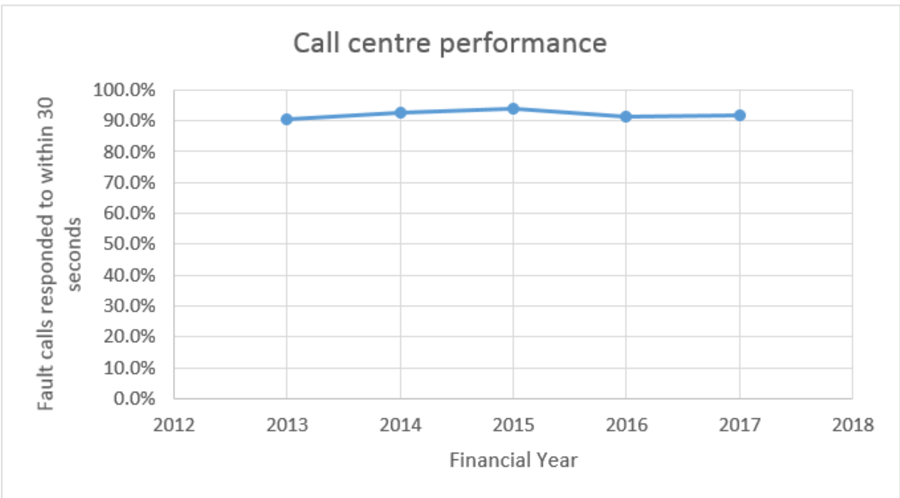
The SAIDI measures were reasonably consistent over the AA3 period, except for the CBD. For the Urban and Rural SAIDI measurements, performance in the final three years of AA3 improved compared to the first two.

The SAIFI performance during AA3 is shown in Figure 54.

Figure 54 AA3 SAIFI Performance

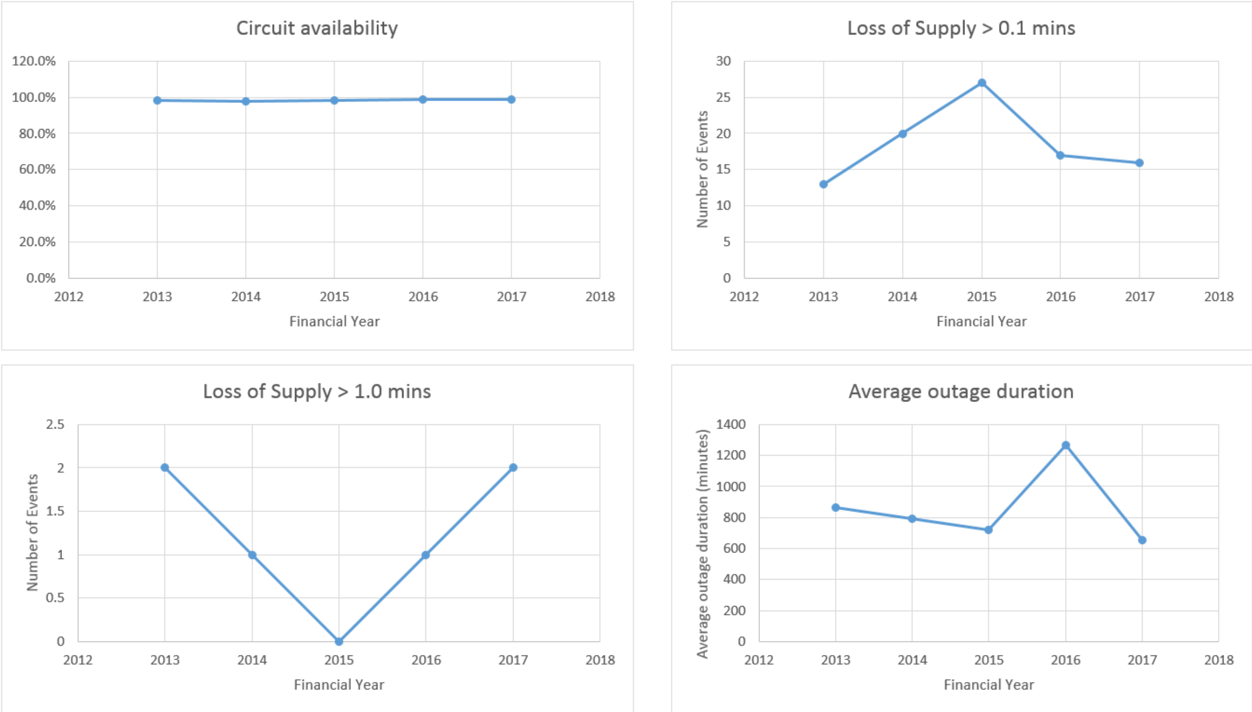
Similarly to SAIDI performance in the CBD, SAIFI performance is volatile in the CBD. Excluding the first year of AA3 for the CBD, a downward trend is noticeable. For the urban and rural SAIFI measures, a downward trend over AA3 is apparent.

Figure 55 AA3 Call Centre performance



Call centre performance remained above 90% for the entirety of AA3, fluctuating between 90-94%.

Figure 56 AA3 Transmission Service Standards Performance



Circuit availability improved over the last 4 years of AA3, from 98.0% to 98.9%. Loss of Supply events fluctuated over the AA3 period. Average Outage Duration showed a decreasing trend over AA3, with an anomalous result in FY2016.

Level 9 145 Ann Street Brisbane QLD 4000 Australia
GPO Box 668 Brisbane QLD 4001 Australia

61 7 3316 3000
advisory@ghd.com

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