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ECONOMIC REGULATION AUTHORITY OF WESTERN AUSTRALIA

WESTERN POWER AA5 EXPENDITURE REVISED PROPOSAL REVIEW

SUPPLEMENTARY REPORT

MARCH 2023

DOCUMENT CONTROL

About this Document

Document Name	Review of Western Power AA5 Expenditure Revised Proposal – Supplementary Report
Version #	FINAL v1.3
Prepared by:	Engevity
Approved by:	Craig Chambers, Managing Director
Date Final Report Approved:	2 March 2023

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Future-focused and progress orientated, Engevity works with organisations to expertly navigate the complexities of change. We create value through transition by offering innovative thinking, expert guidance, pragmatic advice and smart solutions – leading us to a more sustainable future. Engevity's model is agile, solutions-focused and centred around our people & our client's needs.

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1.0 INTRODUCTION

On 15 November 2023, Western Power responded to the Economic Regulation Authority's (ERA's) draft decision on proposed revisions to the fifth access arrangement (AA5) – spanning 1 July 2022 to 30 June 2027 ('Revised Proposal').

The ERA engaged us, Engevity Advisory, to provide technical advice to assist the ERA with its assessment of Western Power's revised regulatory proposal.

Western Power has not accepted the ERA's draft decision and updated its expenditure forecast to include new programs of work. We have undertaken a targeted review of the following aspects of Western Power's Revised Proposal:

- changes to augmentation requirements due to an updated demand forecast (section 2)
- additional expenditure for distribution growth to address the impacts of the 2021 Christmas Heatwave, recommendations from an independent report into the Christmas outages and forecast uptake of EVs (section 3)
- concerns about risks created by the ERA's reduced replacement expenditure (REPEX) forecast (section 4)
- a significant increase in the volume of ICT, SCADA and Comms expenditure to address risks that Western Power considers cannot be covered under the draft decision allowance. Mainly relating mainly to cybersecurity (section 5)
- step changes to the operating expenditure (OPEX) forecast to account for new or increasing costs related to insurance, the silicone treatment program and private pole inspections (section 6)
- a higher OPEX productivity growth factor for the 2022–27 period compared to the ERA's draft decision (section 7).

We have considered the new material and supporting justification put forward by Western Power in its Revised Proposal and additional documents subsequently provided to the ERA to form our final advice to the ERA.

Overall, we do not consider there is a sufficient basis for the ERA to change its draft decision on the above aspects except relating to some new expenditure relating to distribution growth.

2.0 DEMAND FORECAST

2.1 Summary

We have reviewed Western Power's updated forecast for the Revised Proposal to determine whether the changes from its original proposal adequately supports the additional CAPEX for sought by Western Power – above and beyond the ERA's draft allowance.

We recognise that Western Power has responded to some of the issues raised in our prior report, as well as the findings from the Shepherd Report. However, several material issues remain in relation to the incorporation of demand management, DER orchestration and customer response to AMI/flexible tariffs that remain poorly addressed by Western Power.

Western Power's Revised Proposal still does not adequately recognise or account for the benefits it expects to realise from:

- the planned advanced metering infrastructure (AMI) rollout – which enables cost-reflective tariffs to minimise or avoid the need for network augmentation
- Project Symphony and WA Government's DER Roadmap – which is designed to orchestrate customer distributed energy resources (DER) to manage the network load, stability and utilisation more dynamically.

As such, we still hold concerns that Western Power's forecast - and the associated revised CAPEX forecast does not reflect the impact, risk mitigation and benefits of its significant planned and historical investments to better manage demand, stability and reliability of the network

2.2 Western Power's Revised Proposal

Western Power's proposed changes to the demand, energy and customer number forecast from the original proposal to the Revised Proposal are outlined below.

2.2.1 Demand

Demand (measured in MW or MVA) represents the power flowing through a network element at a point in time. It is the critical parameter in establishing the capacity of network components and determining their appropriate size in the system.

Prudent and efficient augmentation planning

The demand forecast at both a system and a spatial (local network element) level mainly informs augmentation planning and the associated investment in new power transfer capacity in the network over the planning horizon.

Ideally, network augmentation investment occurs:

a) just prior to customer load exceeding the capacity of the network

b) at a scale that is economically efficient when considered against expected trends in future customer needs (such that today's customers are not bearing the cost of financing underutilised capacity that was a speculative provision for future needs).

Over most of the history of electricity networks, capacity planners have relied on the fact that continuing positive growth in customer demand meant that there was a natural limit in any 'inefficiency' arising from investment in additional capacity before it is actually required by customers. This is because any 'over-investment' in capacity would reasonably be expected to be taken up by future growth over a relatively short (5–10 years) time horizon – making provision for this 'over-investment' relatively efficient in hindsight.

Western Power's central demand forecasts are relatively flat and energy forecasts are declining at a system level for the AA5 period. This does not reflect the 'safer' sustained growth planning environment that existed prior to the unexpectedly rapid uptake of customer DER during AA4.

In practice, planning for growth translates to providing additional capacity above the immediate capacity when sizing equipment in order to provision for future growth expectations. This practice is specifically endorsed in the Access Code[1] to the extent that it …"reflects the amount that would be invested by a service provider efficiently minimising costs.". This means that larger increments remain prudent and relatively efficient when demand is expected to continue growing at typical sustained growth rates over time – but would fail to satisfy this NFIT requirement in cases where the demand forecast does not provide adequate assurance of continued (or any) growth over the asset life.

Challenges in a low, or lower-than-forecast, demand growth environment

With a flat, low growth or declining demand forecast, much greater care is needed in making augmentation planning decisions. This is because the timing for augmentation needs can frequently be shifted by years, decades, or indefinitely, owing to small variations between forecast and actual demand growth rates. Over the past 10-15 years, Australian electricity networks have brought forward, pushed back or avoided, billions of dollars in augmentation investment due to relatively small changes in the low demand growth environments that have been predominant since the historical network peak demand across all NEM regions (except Qld) between 2008-2011. [2]

The following table highlights that Western Australia's demand growth peaked in 2016, some five to eight years later than 4 of the 5 NEM regions, which is a likely contributor to the unforeseen need to respond aggressively to the scale and growth rate of customer DER installations that occurred over AA4.

Table 1 – Reported historical peak operational demand dates for NEM Region and the WA WEM

	Historical Peak (MW)	Date Occurred
Qld	10,179	13/02/2019†
NSW	14,764	1/02/2011
Vic	10,490	29/01/2009
SA	3,397	31/01/2011
Tas	1,884	21/07/2008
WA (WEM)	4,006	08/02/2016††

Source: AEMO NEM and WEM Historical Data

† the later historical peak for Qld reflects ongoing growth from the significant additional LNG export load that was introduced during the 2010's.

†† The demand experienced during the 2016 heatwave remains above.

1 *Electricity Networks Access Code Section 6.52 – New facilities investment Test*, investment satisfies the NFIT if…*"a) i) … the new facility exhibits economies of scale or scope and the increments in which capacity can be added"*

2 We recognise that flat or declining system level demand does not indicate that there is zero need for investment in capacity – as augmentation will still be required to meet the inevitable 'pockets of growth' from new development that will be offset overall by customer generation, energy efficiency, demand declines in other areas of the network and the ramp down of sunset industries.

It is critical that Western Power's augmentation planning recognises the dramatic and asymmetric change in the demand environment and optimises augmentation decisions across the short term and long term risks, options and alternatives with much greater rigour than may have has been necessary in the past. In particular, the following factors need to be considered in augmentation planning:

- responding first with operational measures, contracted non-network services and customer incentives (such as load/export control, flexible tariffs and VPP services)
- staging capacity additions to leverage staging capacity additions to leverage the optionality to defer/abandon/change subsequent stages of augmentation plans if growth does not eventuate as predicted over the forecast timeframe
- revisiting efficient capacity increments to recognise the asset stranding risk mitigation provided by smaller augmentation increments
- challenging planning provisions for future growth - reconciling these provisions against the medium term P50 planning forecasts of flat demand and declining consumption.

Where these measures have not been addressed, and no adjustment is made to the revised CAPEX proposal, Western Power could either:

- realise these 'efficiencies' during AA5 (that should be incorporated into an efficient regulatory CAPEX forecast) and effectively obtain a CAPEX contingency by way of avoided investment
- continue with historical practices that inherently favour network augmentation investment over operational and customer responses – passing the risk of Western Power's forecasting to customers, without taking prudent measures to mitigate the customer's exposure.

Neither of these outcomes is consistent with an efficient or favourable outcome for WA electricity customers in accordance with the efficiency requirements of the Access Code.

Delaying the detailed consideration of non-network and customer based solutions as central to the augmentation planning process significantly reduces the benefits realised from Western Power's own significant investments in AMI, SCADA, Communications, Supporting IT systems and Network Orchestration. Ultimately, to include these initiatives in the CAPEX forecast alongside the requested additional augmentation CAPEX (that has not incorporated the benefits and optionality provided by the former strategic investments) would double count the actual requirements in these areas.

Option Value and Risk Transfer from Smaller Augmentation Increments

To highlight the value and risk mitigation benefits of smaller augmentation increments the table below illustrates the proportion of capacity that is used for augmentation in arbitrarily small 10kVA increments and the proportion of the augmentation cost that is attributed to future customers, without providing useful service during the current Access Arrangement period. This also holds for strategies that seek to stage investment over time to better match actual customer load requirements.

It highlights that when 10kVA augmentation increments are applied to an illustrative 100kVA network element (i.e. a minimum 10 per cent capacity augmentation), around half or more of the capacity (and therefore cost recovery) remains unutilised over the first five years at growth rates of less than 2 per cent p.a. We note that this is approximately double the recent WA population growth rate forecast by the WA government.

At lower (and negative) demand growth rates, an increasingly large proportion of the capex risks being partly (or entirely) stranded from an economic perspective. This is where the asset is physically available on the network but it is not required to serve customers. These assets would add (or retain) cost for customers, without providing useful service for much of their installation lives.

For some assets, there is a non-trivial risk (given the flat trajectory of Western Power's 50 PoE base forecast and declining growth outlook for its 90 PoE forecast) that augmentation investment will be made by Western Power in AA5 and the assets may never be required, or only become necessary some decades into the future when the asset has subsequently degraded in the field at the expense of WA electricity customers – through its recovery via the RAB. This is especially relevant for assets that cannot economically be relocated – such as distribution feeders.

Importantly our assessment reflects a 'best case' with extremely granular control over augmentation, with incremental augmentation often "planned-in" to augmentation scope based on adopting post investment plant configurations that can double capacity (i.e. adding a second transformer at a single transformer substation of the same capacity).

The effect of the adoption of larger (50 per cent of element capacity) augmentation increments is also considered below for comparison. Which shows how augmentation risks increase with the increment and inappropriately transfers the current forecasting accuracy and planning risk onto future customers.

Table 2 – Indicative proportion of notional augmentation cost passed to future customers via RAB without benefit over a 5 year horizon – for illustrative 100kVA element/10kVA augmentation increment

Growth Rate (% p.a.)	New Capacity forecast to be needed (5 yr)	Augmentation Size	Years to absorb new capacity	% of New Capacity Used (5 yr)	% Passed to Future Customers (5 yr+)
<= 0.00%	-	**10 kVA**	Never	0%	100%
0.25%	1 kVA		40	13%	87%
0.50%	3 kVA		20	25%	75%
0.75%	4 kVA		13	38%	62%
1.00%	5 kVA		10	51%	49%
2.00%	10 kVA	**20 kVA**	10	52%	48%
3.00%	16 kVA		7	80%	20%
4.00%	22 kVA	**30 kVA**	8	72%	28%
5.00%	28 kVA		6	92%	8%
6.00%	34 kVA	**40 kVA**	7	85%	15%
7.00%	40 kVA	**50 kVA**	7	81%	19%
8.00%	47 kVA		6	94%	6%
9.00%	54 kVA	**60 kVA**	7	90%	10%

Source: Engevity Analysis – Illustrative Only

When the analysis is repeated for a situation where the augmentation increment is 50 per cent of the existing capacity (i.e. adding an extra feeder to a two feeder route) the risk that assets will be underutilised or stranded increases substantially – with more than half of the capacity remaining unused over the next five years for sustained growth rates below 4 per cent p.a. – which is well in excess of long term population and economic growth trends that drive electricity demand at the macro level.

Table 3 – Indicative proportion of notional augmentation cost passed to future customers via RAB without benefit over a 5 year horizon – for illustrative 100kVA element/50kVA augmentation increment

Growth Rate (% p.a.)	New Capacity forecast to be needed (5 yr)	Augmentation Size	Years to absorb new capacity	% of New Capacity Used (5 yr)	% Passed to Future Customers (5 yr+)
<= 0.00%	-	**50 kVA**	**Never**	**0%**	**100%**

Growth Rate (% p.a.)	New Capacity forecast to be needed (5 yr)	Augmentation Size	Years to absorb new capacity	% of New Capacity Used (5 yr)	% Passed to Future Customers (5 yr+)
0.25%	1 kVA		**200**	**3%**	**97%**
0.50%	3 kVA		**100**	**5%**	**95%**
0.75%	4 kVA		**67**	**8%**	**92%**
1.00%	5 kVA		**50**	**10%**	**90%**
2.00%	10 kVA		**25**	**21%**	**79%**
3.00%	16 kVA		**17**	**32%**	**68%**
4.00%	22 kVA		**13**	**43%**	**57%**
5.00%	28 kVA		**10**	**55%**	**45%**
6.00%	34 kVA		**8**	**68%**	**32%**
7.00%	40 kVA		**7**	**81%**	**19%**
8.00%	47 kVA		**6**	**94%**	**6%**
9.00%	54 kVA	**60 kVA**	**11**	**54%**	**46%**

Source: Engevity Analysis – Illustrative Only

We remain concerned that Western Power's forecasting and planning processes and project scoping practices appear to:

a) focus on augmenting the network as the most favourable option

b) implicitly assume (based on the financial analysis templates provided) that demand growth will continue for the life of the network asset, the asset will remain the most appropriate technology and customers will require the asset for its full service life

c) assume that the same discount rate applies over a notional 40-year life of the network assets – ignoring the very significant option value of shorter term solutions in an environment with higher rates of technology change, upward pressure on project evaluation discount/hurdle rates[3], and high demand forecast uncertainty.

d) compare non-network options based on the much longer life of the network asset – and not the deferral value over the period met by a much shorter-term augmentation alternative (e.g. contracted demand management, customer incentives for VPP batteries)

e) put aside the significant impact of the avoided network augmentation impacts arising from its flagship AA5 CAPEX initiatives (investment to enable flexible tariffs, project symphony, the SPS program, facilitating customer owned DER through AMI and other measures)

f) provide limited assurance that more efficient OPEX or short-term CAPEX solutions have been evaluated – such as LV/MV level phase balancing of load and generation, greater

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3 Project evaluation discount rates are typically set with reference to a firm's financing costs. A higher discount rate should have the natural effect to reduce the volume of Capex that can be justified – particularly for long life assets where their long term benefits are discounted more aggressively.

Applying a higher discount rate to investment evaluation models also makes short term management, staged, smaller investment increments and shorter life assets more compelling. To appropriately recognise the investment optionality from shorter life solutions – either a) the probability weighted likelihood of reinvestment actually being required to achieve the same life of the network asset, along with b) the technology cost curve benefits (reduction in battery/microgrid/DER orchestration technology costs over time) forecast for the time of each renewal.

We did not see evidence that Western Power had considered the impact of a higher WACC on its CAPEX decisions or attempted to reasonably quantify the option value of shorter life technologies and less capital intensive solutions in developing either its original or Revised Proposal.

segmentation to minimise the proportion of customers affected by an outage, and changes to operational practices to restoring power in high bushfire risk conditions

g) overlook the highly material risks of the proposed augmentation investment in AA5 becoming stranded in the forecast flat or falling demand environment (as highlighted above).

As a result, we reiterate our concern around the quantification of risk, uncertainty, timing, investment horizon and the significant unrecognised value of optionality within the Western Power augmentation and replacement CAPEX forecasting processes.

The forecast for flat or declining demand, along with specific spatially diverse capacity limitations means that both major (e.g. increase zone substation transformer capacity) and minor (new distribution feeders/distribution substations) CAPEX solutions are vulnerable to stranding risk – particularly under the faster transition scenarios with greater customer supply autonomy via customer funded DER. This means that the timing for each of these investments should be carefully scrutinised prior to financial commitment.

Changes to Western Power's augmentation forecasts

A key theme of the adjustment to Western Power's capex is the impact of the December 2021 heat wave on demand – which had the greatest effect at the lower levels of the network that are not always captured in the total network or major substation level forecasts. As a result, the focus of the forecasting review is on these lower level elements in Western Power's distribution network.

Extreme heatwaves have been, and remain, a challenging environmental factor in managing a network as they are significant, but not frequent events, with extended extreme heatwaves typically assigned a one in 10-year probability by most Australian distribution businesses. As a result, reinforcing the network with additional infrastructure to withstand an extreme heatwave becomes far more capital intensive as it would effectively increase the planning forecast to a highly conservative 10 per cent probability of exceedance (under forecasting) / <u>90 per cent probability of over forecasting in any single year</u> (in contrast to the 50 per cent probability of under forecasting / 50 per cent probability of over forecasting that is typically used by Australian networks for planning purposes).

Importantly, this does not mean that the network cannot continue to provide service through an extended heatwave on a network that is planned to a 50 PoE forecast because not all parts of the network are fully loaded at the same time,, the network/AEMO load shedding schemes do provide emergency measures to respond to rare events, the planning criteria, the ability to redirect load between larger substations/adjacent feeders (as outlined in the Technical Code and conducted reactively during the recent heat wave response) and the prudent allowances for future load growth in newer equipment that has not yet been absorbed by new demand will all allow some degree of infrastructure flexibility for market and network operators to manage loading and supply side risks through heatwave days.

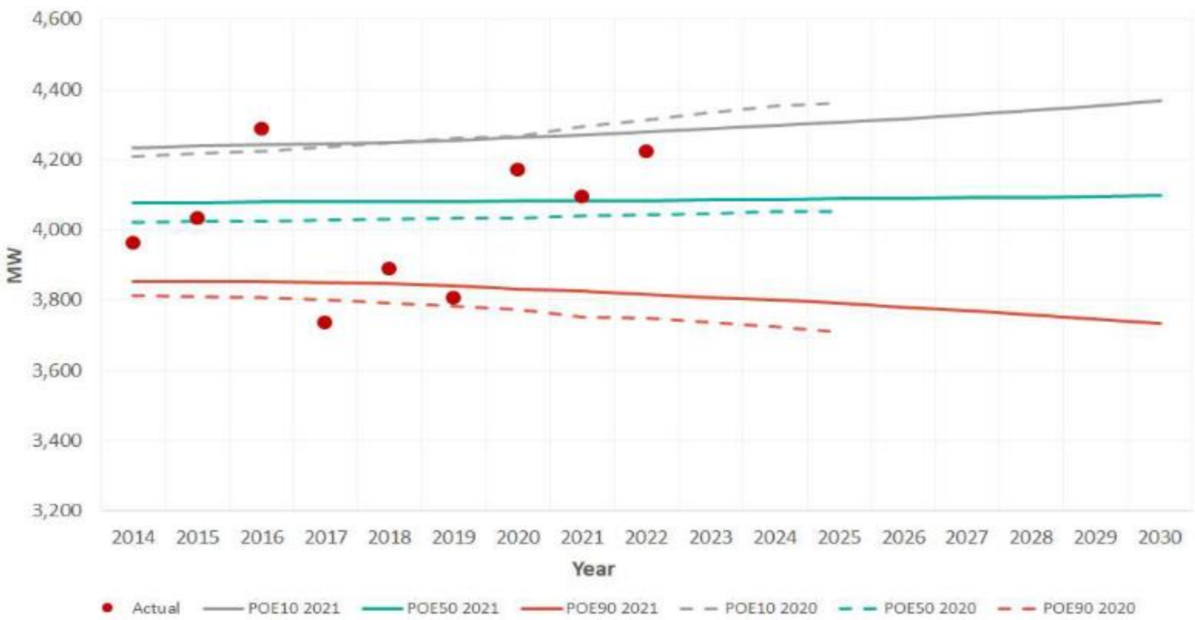
The circa 50 per cent AMI penetration and completion of the full scale roll out in AA5 in expected to drive greater customer demand elasticity in peak periods, disconnect/reconnect capability and export control at every meter and SPS programs significant transfer of long rural customers off the problematic long rural feeders – where the longest delays to restoration, greatest exposure to bushfires and lowest reliability outcomes occur. Significantly, Western Power's transition strategy envisions a much larger deployment of SPS over the next 10-15 years which would mitigate the scale much of these risks (particularly the impact on maximum outage durations) by the natural resilience of disconnected systems. It would also allow resources that are currently deployed to the long rural areas to respond to impacts in more densely populated (higher reliability risk) areas during extreme events. We have not found compelling evidence to indicates that these factors have been factored into Western Power's decision making for AA5.

The Shepherd Report also highlights a range of potential operational responses to mitigate the outage duration experienced during emergency events – such as weighing the risk of bushfire ignition during re-energisation against the significant health and safety impacts of loss of supply on people and animals. The recent NSW bushfire review also highlighted the critical role that electricity networks play in enabling emergency communications of changing conditions, electronic payments and ongoing functioning of economies cut-off by fires to minimise unnecessary demand on key roads and other evacuation routes. The recommended evaluation of these very material safety, economic and community benefits with relevant community and government stakeholders may establish a revised view on balancing the risk to Western Power of a fire start during re-energisation with the broader economic cost of reliability impacts during emergencies.

Improvements to Western Power customer communications during outages also delivers benefits to non-rural customers to accelerate reporting times, best allocate customer resources staff and remained more fully informed during outages.

In WA, the 2021-22 heatwave was significant, but the reported demand remains within the 10 per cent PoE band published by Western power in its Transmission System Plan, and below the level of the historical peak in 2015-16 – which was also driven by an extended heatwave.

Figure 1 Historical and forecast system maximum demand – 2020 and 2021



Source: Western Power Transmission System Plan 2022[4]

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[4] The Western Power reported historical system demand of approximately 4,300MW in 2016 exceeds the AEMO reported WEM maximum historical demand of 4,000MW. The AEMO figures are based on sent out generation for the purpose of operating the WEM.

From a review of the AEMO ESOO data for WA, Engevity notes that the difference appears to be the distinction of 'System Maximum Demand' (inclusive of customer solar PV that is meeting load behind the meter) and 'Operational Maximum Demand' (the generator demand needed to satisfy the 'System Maximum Demand' excluding the component met behind the meter by customer DER.

Given the following observations:

a) The reliability impact of the heatwave was most acute in the more rural areas that are affected by high bushfire risk weather conditions, which Western Power considered would preclude re-energisation until conditions improved

b) The Shepherd Report also highlights improvements in operational practices, customer communication and information dissemination to reduce the duration of the outages, enable messaging to the community to conserve power.

c) The issue of overloads on reconnection could be mitigated through finer sectionalisation of feeders to allow power to be more progressively restored to customers in a manner that does not bring on all temperature sensitive refrigeration and air conditioning load at once and allows customer DER to reconnect and then offload a material portion of the household demand on the network.

d) Switching, network reconfiguration, phase balancing, feeder load balancing, local storage or generation, the control of AMI remote connection/disconnection and export limit functionality as well as pre-emptive field crew deployment, summer preparedness programs and other operational measures are available to Western power to manage demand extremes.

We note that much of the risk is addressed through an improvement in Western Power's operational responses in extreme events. Most notably communication to customers and the co-ordination of customer demand. Western Power implemented a new customer management system in AA4 that enabled making many self service capabilities and network outage conditions known to customer service staff (and ultimately customers).

Many Australian DNSP's have provided self service portals, outage/cause/restoration time maps, and live updates via corporate websites, on hold messages, social media and traditional media for over a decade. They have seen substantial efficiency benefits from these initiatives through:

- **reduced calls needing to be answered** (call centre hold messages "if you are calling to report the outage at [location] we are aware of the situation and [a crew is investigating / the expected restoration time is [x] minutes – refer to our website or social media for further updates")
- **Faster customer notification of new outages** because most of the calls are addressed through the hold message so customers with a new report are able to reach a customer service representative faster.
- **Greater customer self service** via the website and social media updates in the future – resulting in lower call volumes, and a transfer in contact preference to self service channels.

supply shortages. The Shepherd Report also made several recommendations to improve customer communications during emergencies or extended supply interruptions. There is significant potential for Western Power to leverage the communications improvements that arise from its historical and ongoing investment in its customer management system to provide a stronger operational response, leveraging customer participation to manage demand in unusual (one in ten year) conditions - in preference to investment in assets that may only be required by customers on a couple of days each decade.

Notwithstanding the above discussion on the relatively flat system level maximum demand forecast, the revised 50 PoE forecast does result in a number of specific distribution augmentation requirements at the lower levels of the distribution network.

2.2.2 Additional Distribution Network Augmentation

Distribution network equipment is typically given several different ratings, depending on the frequency and duration of operation at high loads over time. These frequently involve short term transformer operation at 130 per cent or more of their nameplate rating during localised peak events that occur infrequently.

This common practice reduces the expected life of the equipment to a small extent – as it is exposed to higher temperatures and operating currents for longer periods. However, it also allows networks to avoid responding with significant investment to situations that occur infrequently or otherwise to avoid adding capacity in response to one-off events that may not occur again at that location.

A typical network response to overloads from heatwaves is to:

a) Address the equipment that poses safety or reliability issues through normal operational response

b) Establish the causes of the overload and consider the extent that rebalancing load (and DER output) between phases and minor reconfiguration of the network in meshed or 'meshable' urban areas

c) Sectionalise longer feeders to allow progressive re-energisation by line section so that power can be restored outward from the zone substation – such that the load is introduced in steps, allowing the start-up demands of appliances like refrigerators and air conditioners to be brought on gradually[5] (noting with AMI, the network is effectively 'sectionalised' down to the individual customer level with remote switching control)

d) Consider the volume of customer / network generation, storage or load absorption that is required on the feeder to bring the overload within network loading limits, stability criteria and cyclic ratings of equipment

e) Establish the cost of alternative storage, standalone power system (SPS), emergency generation or emergency microgrid operations vs feeder / street transformer replacement / augmentation

f) Evaluate the extent to which the augmentation activities interact with the replacement program CAPEX allowances for lines and street transformer replacement due to risk and condition

g) Adjust the replacement program downward to allow for the value of augmentation driven replacement work, non-network solutions, accessible customer DER and augmentation driven reliability improvement works

For Western Power the existing coverage of around half of their customers with AMI meters presents the very substantial opportunity to establish protocols and customer acceptance to leverage the remote disconnection-reenergisation functionality as an emergency operational tool[6] and make

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5 This has the additional benefit of enabling physically shorter line patrols for each section to allow faster restoration of supply to customers closest to the zone substation and isolation of the faulted section to minimise the supply disruption to customers. These operational and management approaches could have significantly addressed the outage length, repeated tripping and allowed access to a greater number of shorter length of 'weather windows' to perform line inspections following outages during high bushfire risk conditions.

6 The establishment of remote connection/disconnection capability for each meter under the AMI program creates a level of control that can be used for emergency operational control of load and export. The value of this capability could grow substantially as customer energy storage penetration increases. This is because critical network events are typically relatively short (less than a minute to 2-4 hours) and typical 5kWh-20kWh residential battery installations and meet a sustained 5kW demand for 1-4 hours.

complementary extensions of the Project Symphony orchestration initiative to provide greater resilience, adaptability and reliability using existing (and already planned) assets.

Western Power incorporated some, but not all of these steps into its response. For example, we did not identify where consideration had been given to establishing more widespread island-able microgrid capability as an alternative, respond with operational responses such as transportable generators, leveraging customer DER, implementing risk based equipment ratings, minor reconfiguration, pre-summer LV phase balancing, adding local network storage or other load management, monitoring and distributed supply solutions to respond more effectively to events with a frequency that falls towards the more extreme end of the network planning assumptions.

Given Western Power's pilot programs and knowledge building activities in AA4 to implement microgrids, deploy SPS units and demonstrate DER co-ordination through Project Symphony, Western Power's apparent preference for traditional network solutions in its planning and capital forecasting process casts doubt on the business' commitment to these solutions as a ready and viable alternative to conventional network augmentation.

In particular, we note that the Business Case for the 'Accelerated Capacity and Reliability Works (2022)' does not quantitatively assess any solution other than Western Power's Network Augmentation options.

The business case financial analysis implicitly favours long life network infrastructure by ignoring any option value embedded in shorter life assets by setting the Investment Evaluation Model assessment over the 50 years to the year 2072, and the business case presents no sensitivity analysis to conclude that:

> *"The recommended option is assessed to be the only feasible option to effectively mitigate the risk level posed by Summer 2022/23."*[7]

The below options analysis table illustrates the qualitative nature of the analysis of non-network alternatives

We also note that the clear interaction with the lines and cables programs means that much of the feeder risk is already provided for through the replacement program – or otherwise significant synergies in cost and delivery could be realised by replacing an existing asset with a similar but higher capacity asset. In this case, the additional capacity becomes an incremental expense on the core replacement driver.

Technically, the remote connection/disconnection capability and communications backbone will be put in place via the AMI rollout, in time for a potential resumption in the market take up of home batteries and electric vehicles.

This flexibility could foreseeably be contracted via a third party VPP, or through a network pricing product that guarantees a minimum of say 20 to 22 hours per day in return for a reduced daily supply charge (or capacity/demand charge exemption) – to recognise that these customers have invested in their own supply such that they no longer require or benefit from the full reliability performance of the network. At scale this, could provide 'at-call' demand and load management that could temper peaks and ramp rates (by offloading battery customer demand in the evening – but also timing charging loads to occur during the minimum demand daytime period.

To realise these mutual benefits, innovation during AA5 will be necessary for the Network and Customers to make complementary and efficient private and shared investments.

7 Western Power, July 2022, *Detailed Business Case for Approval – Accelerated Capacity and Reliability Works:2022.* p.14

Figure 2 - Assessment of Options against the Evaluation Criteria

#	Option Title	Technical Feasibility	Meets planning limits	Meets operational limits	Effectively Mitigate Risk	Deliverable by Nov 2022	Reflects Prudent Investment NPC ($M)
1	Do Nothing	✓	✗	✗	✗	N/A	N/A
2A	Network Augmentation (Limited scope)	✓	✗	✗	✗	✓	$10.44
2B	Network Augmentation (Full scope)	✓	✓	✓	✓	✗	Not financially assessed
3	Network Switching	✓	✗	✗	✗	✓	$0.17
4	Install grid connected battery storage	✗	Not assessed	Not assessed	Not assessed	✗	Not financially assessed
5	Provision of demand control services	Not assessed	Not assessed	Not assessed	Not assessed	✗	Not financially assessed
6	Hybrid (Option 2A + Option 3)	✓	✗	✓	✓	✓	$10.61

Source: Western Power Detailed Business Case for Approval – ACR 2022

2.2.3 Forecast of overloaded feeders and substations

At a total network level, the demand forecast has seen modest changes and improvements resulting in a small change to the overall demand.

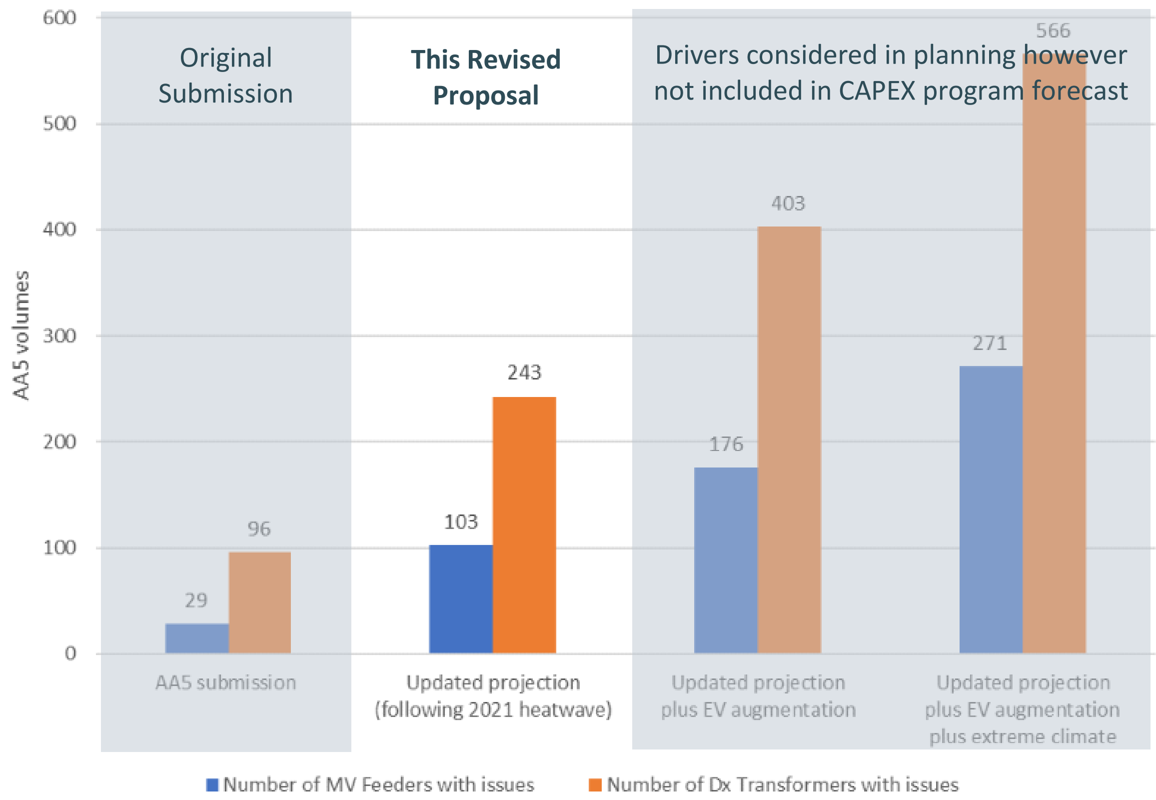
A significantly higher volume of overloaded MV feeder and street transformer assets have been forecast at the lower voltage (customer) end of the network – downstream of the zone substations.

Notwithstanding this additional work, Western Power's immediate response to the overloads was to restore supply by load transfers, reconfiguration and operational measures which have managed the immediate needs in the short term. In the longer term the implementation of the Shepherd Report recommendations for improved customer communication (allowing a greater degree of voluntary curtailment), revised restoration practices to minimise customer time off-supply as well as the use of the much finer control that becomes available with existing and new AMI installations (to co-ordinate automated reenergisation/load shedding and maximise the use of customer DER at a very fine level of control).

Western Power has also included the additional consideration of EV demand as well as the consideration of loading during extreme weather events – in response to the Shepherd Report recommendation for planning improvements.

These adjustments have been considered in the planning process and a decision made by Western Power to exclude the cost associated with these overloaded feeders and street transformers from the capex forecast – effectively acknowledging that they represent a significantly more conservative case than is prudent for network planning at this stage.

Figure 3 - Forecast medium voltage feeder and distribution transformer issues



Source: Western Power - Response to ERA's draft decision (emphasis added)

The relevant clauses of Western Power's Distribution Design Criteria are summarised in Section 2.6 a) and b) of the Technical Rules as follows:

"2.6 Distribution Design Criteria

a) All distribution systems must be designed to supply the maximum reasonably foreseeable load anticipated for the area served. The maximum reasonably foreseeable load must be determined by estimating the peak load of the area after it has been fully developed, taking into account restrictions on land use and assuming current electricity consumption patterns.

b) Distribution systems must be designed to minimise the cost of providing additional distribution system capacity should electricity consumption patterns change…."

These two criteria summarise the conflicting obligations that Western Power must reconcile through its augmentation planning and investment decision making. For the incremental CAPEX sought in Western Power's Revised Proposal, Western Power needs to consider (among other factors):

a) The maximum reasonably foreseeable load,

b) The current electricity consumption patterns, and

c) How to minimise the cost of providing additional capacity should electricity consumption patterns change.

Given the flat or declining forecasts for both energy and demand, the reasonableness of an assumption of a sustained and continuous demand growth rate at certain sites should be justified- as well as the need for the cost to be fully recovered through the regulated asset base. With residential customer load declining due to increasing DER penetration, it is difficult to reconcile demand growth at these locations in the absence of new development

To avoid the risk of over-investment and extremely high cost impact associated with adopting excessively conservative planning and reliability standards, Australian networks are normally planned based on a P50 (most likely) forecast, with actual reliability performance measures and incentives used to measure and reward network businesses for their operational (field practices, response times, switching, automation, use of cyclic ratings, response prioritisation) and asset management (spares availability, condition monitoring, condition forecasting, failure risk mitigation) responses to events that result in actual loading exceeding the (weather corrected) P50 forecast.

Western Power responds to some concerns raised for the Draft Determination (such as treatment of growing EV demand), however do not adequately consider the effect of factors such as likely battery uptake, the AMI program and uptake of cost reflective tariffs and co-ordination of customer DER as an outcome of Western Power's ongoing investment in Project Symphony.

The implications on the revised CAPEX proposal are discussed further in section 3

2.2.4 Energy

The starting point for the energy forecast has significantly increased over AA5 from 17,356 GWh to 18,091 GWh, with a similar rate of decline evident over the period. This results in the decline in energy transported over the network to effectively be deferred by over 5 years.

As a result, the forecast energy sales that were previously forecast for the 2022 starting point no longer occur until the beyond the last year of the AA5 period.

Figure 4 - 2022 AA5 Energy Sales Forecast

	2022	2023	2024	2025	2026	2027
Total actual sales (GWh)	18,415					
Total forecast sales (GWh)	18,091	18,117	18,015	17,852	17,737	17,534

Source: Western Power – AA5 Revised Proposal

In practice, this indicates that the erosion of consumption that was originally forecast over AA5 – due to customer DER uptake and energy efficiency offsetting consumption - is likely to be less acute than originally forecast in terms of the overall impact on pricing. Notwithstanding this, the rate of decline in forecast consumption still occurs at a similar rate over the AA5 period.

The equivalent figures from the original proposal are shown below for completeness.

Figure 5 - 2021 AA5 Energy Sales Forecast

	2022	2023	2024	2025	2026	2027
Total Sales (a)						
Total Sales (2017 f)	17,165					
Total Sales (2019 f)	17,634	17,632	17,634	17,641		
Total Sales (f)	17,356	17,255	17,159	17,058	16,958	16,858

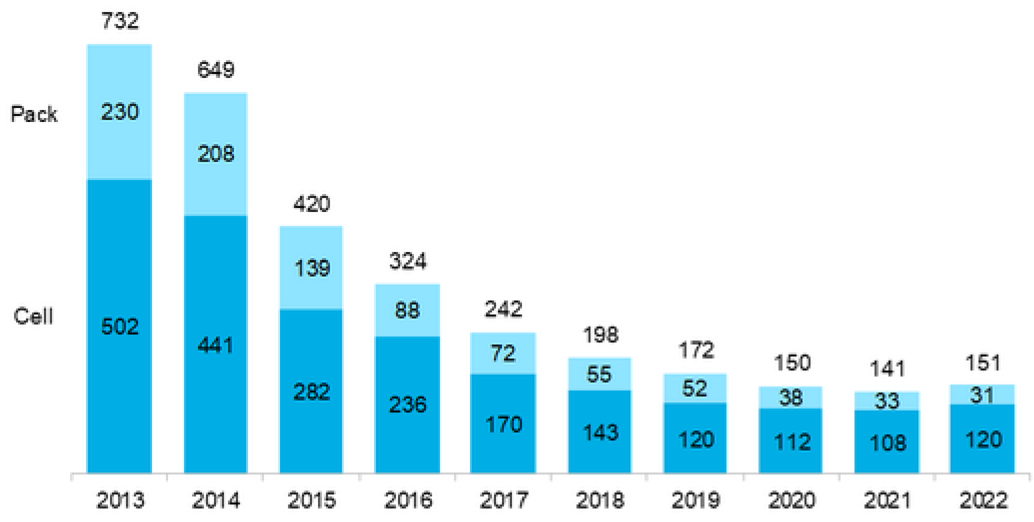
Source: Western Power – AA5 Proposal Attachment 7.5

For customers, a higher energy forecast places downward pressure on network prices by allowing investment to be divided over a greater volume of energy when calculating tariffs. Notwithstanding this, customer uptake of DER can offload the network, allowing more customers to be served by the existing infrastructure.

As shown below, battery storage prices have declined substantially over recent years, with a pause in the rate of decline as demand for upstream supply chain commodities has driven commodity price increases, whilst the supply side responds with new mining and processing capacity. Coupled with the increased diversity of available energy storage product options in the Australian market which have increased well beyond the initial 'premium brand' offerings, high thermal fuel prices on international markets, the potential for energy storage to mitigate evening peaks, ramping requirements on thermal plant and daytime minimum demands allows for the utilisation of network infrastructure to be maximised by leveraging the benefits of Western Power's investment in Project Symphony's DER orchestration capabilities over AA4.

Therefore, it is important to note that it is ultimately the utilisation of the network and the value of the assets in the RAB that drives network prices. Lower prices can be achieved through higher energy throughput, serving more customers with the same asset base and/or minimising investment in the network. It is also important to recognise that where customers are able to place lighter demands on the network, higher unit prices (c/kWh, c/day) for network services do not necessarily equate to higher total electricity bills ($ p.a.) – due to their more efficient use of the service (purchase a lower volume of network services – fewer kWh's transported). The design of the regulatory framework and models mean that the pricing and investment trajectory are closely linked by the extent that the assets that are built will remain well utilised over their lifetime.

Figure 6 - Volume weighted average lithium-ion battery pack and cell price split 2013-2022 (real 2022 USD $/kWh)



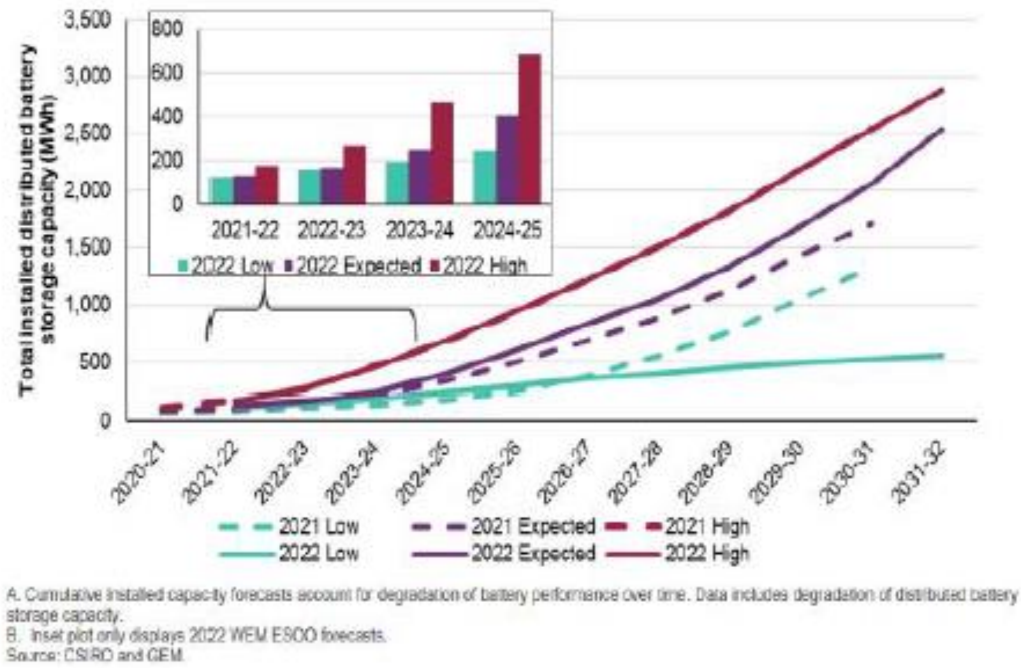
Source: Bloomberg New Energy Finance Annual Battery Price Survey 2022

With lithium ion battery prices remaining under AUD $227/kWh (USD $151/kWh @ AUD$1.50/USD) for the past three years, and 3kWh locally assembled retail products now emerging from multiple Australian suppliers in the off grid market at prices that are less than $300/kWh (ex GST), storage uptake in a higher inflation, high interest rate environment is both a significant risk and opportunity to Western Power's forecast – depending on how it is managed.

It is concerning that Western Power does not consider significant growth in storage as a significant contributor to mitigating augmentation expenditure. The AEMO forecast for battery uptake cited by Western Power identifies that by the end of the AA5 period, almost 200MWh of additional battery storage battery uptake would be installed – equating to a potential 5–10 per cent reduction in the SWIS system peak if deployed into the critical 30min trading interval.

In the 'High' scenario, this increases to around 500MWh – which could notionally cover 12–24 per cent if discharged into the critical 30 minute trading interval. Investments during AA4 in Project Symphony enable VPP operations to orchestrate and automate customer DER which can begin to be realised in AA5. Implementation during AA5 will demonstrate the benefits for customers of network/retailer co-ordinated DER operation over manual user/installer configuration.

Figure 7 - Battery Capacity in the SWIS



Source: 2022 AEMO ESOO

Whilst not reflected in the CAPEX forecast, the likely growth in customer storage, alongside network investments in VPP's, introduction of flexible tariffs and the increase in EV uptake have the potential to add resilience to the network during heat wave events that would further improve reliability and reduce Western Powers reliance on operational risk management measures to allow 10 PoE events to be more efficiently managed operationally rather than through investment in long lived network assets.

Current EV's typically have a battery capacity of 40-75kWh and are increasingly capable of supplying mains voltage appliances directly, with vehicle to home (islanded from the grid) and vehicle to grid (capacity is available to both the home and the grid) capabilities expected to mature over the next 5-10 years.

In the event of a sustained outage, a single EV could comfortably meet a medium to larger household's electricity consumption needs (typically averaging between 12-30kWh day) whilst reserving 50 per cent of capacity for transport or to recharge at a fast charger located outside the areas affected. At this scale, EV's could be implemented in a manner that significantly reduces the volume of stationary storage needed for households to manage their supply – accelerating demand for smaller capacity stationary batteries and improving the financial viability of EV's for consumers. (Whilst simultaneously reducing their need and willingness to pay for high reliability grid supply and increasing the likelihood of grid defection).

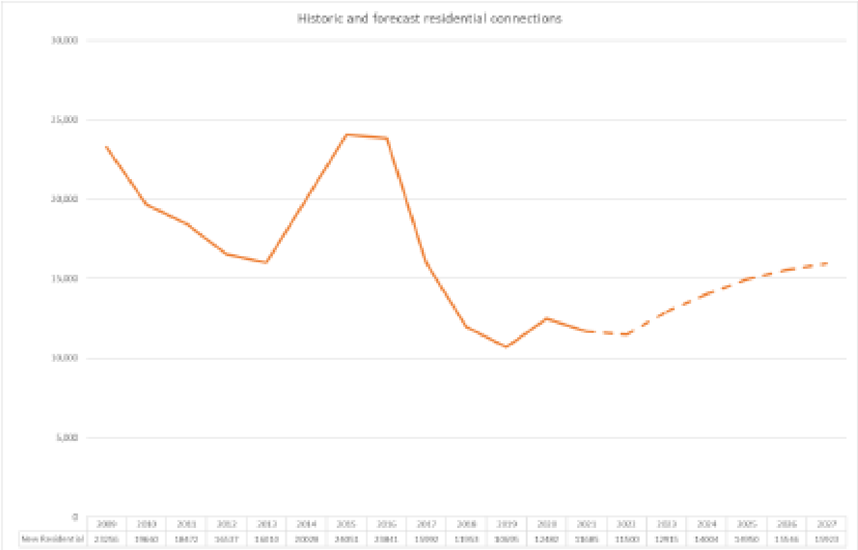
Alternatively, the orchestration of these charging demands and more widespread ability for customers to readily 'back up' their own supply during outages could be instrumental to managing network costs, prices and reliability through the transition. Capturing this opportunity does not yet appear to be a priority in Western Power's planning approach.

2.2.5 Customer Numbers

The longer term downward or flattening trend in energy, connections and demand provides less support for investment in capacity. Planning forecasts at a substation level are generally flat– with more pronounced changes in both maximum and minimum demand at some sites.

These sites are typically single/dominant customer sites or have otherwise been targeted by the additional feeder augmentations proposed by Western Power.

Figure 8 Figure 9 - Western Power residential connections forecast based on 'WA Tomorrow' Data



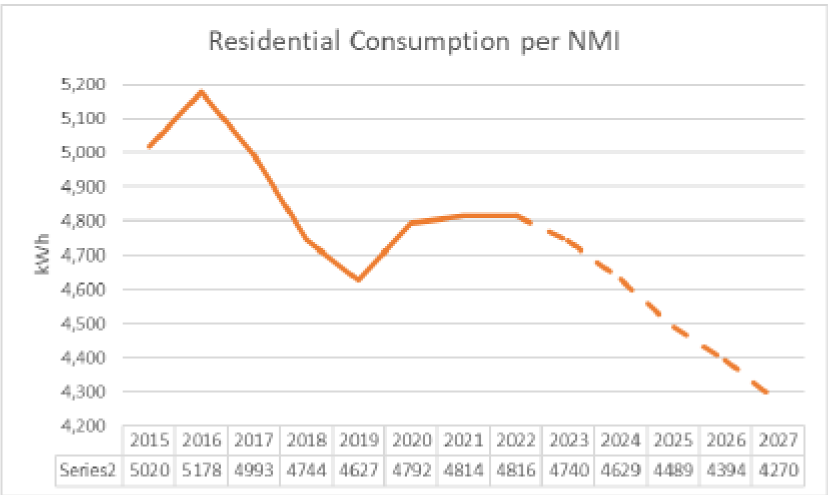
Source: Energy and Customer Numbers Forecast 2021.xlsx [EDM# 61726036]

Source: Western Power

The customer number forecast remains comparable to the prior forecast, reflecting a post-pandemic recovery in construction and interstate migration. However, more downside (fewer customer connections) than upside is also noted due to a higher interest rate environment, challenging construction industry conditions and increased budgetary pressure on consumers due to inflation.

Residential consumption per customer is forecast to continue to decline steadily over AA5, attributable to increasing DER penetration, energy efficiency and customer behaviour. This means that the network can accommodate growth in customer numbers to offset reducing consumption by individual households. Furthermore, the accelerated introduction and take up of flexible tariffs through the AMI roll out is intended to shift significant consumption and demand away from peak periods.

Figure 10 - Residential Consumption per NMI



Source: Western Power

The longer term implications of this trend mean that without strong and sustained population growth over decades – or energy storage[8] and the electrification of transport (and other consumption) arresting the downward trend, infrastructure built today risks becoming significantly underutilised into the future, particularly to serve detached residential areas with much greater DER and energy storage potential.

Whilst the expectations of electrification, DER and other factors are discussed, the fact remains that the forecasts adopted by Western Power foresee growth and efficiency factors to be largely offsetting. Whilst the expectations of electrification, DER and other factors are discussed, the fact remains that the forecasts adopted by Western Power foresee growth, DER, and efficiency factors to be largely offsetting. We note the very wide range of outcomes that are considered in AEMO planning scenarios in relation to the likelihood, timing and scale of these influences on Western Power's network.

Therefore, careful consideration should be given to operational and DER/tariff responses to organic growth driven capacity augmentation needs in outer suburban areas. This will ensure that most of the new investment is driven new connections where capital contributions from the connecting party reduce the impact on the RAB.

2.3 Engevity analysis

Although Western Power has responded to some of the issues raised in our prior report, we consider several material issues remain with its demand forecast and how it is reflected in the capital expenditure forecast. We found:

- Western Power's assessment of extreme weather events and EV uptake trends as 'high case' scenarios in its planning assessment of the MV and LV networks is appropriate to avoid broad scale inefficient investment but ensure that those weather events are considered in planning.
- The approach to exclude investment addressing these matters from progressing to the CAPEX program (based on an equal likelihood of under/over forecasting) and monitor their emergence over AA5 is prudent.
- The revised demand forecast has a limited impact on augmentation requirements at the zone substation and above, and has mainly affected MV feeders and street transformers on the customers side of the zone substation. This is not uncommon following forecasting revisions that update data on actual loading behaviour during recent heat wave events.
- Western Power has not: incorporated the effects of flexible tariff uptake from the AMI program, or given adequate consideration of the benefits from DER orchestration as a result of the Project Symphony investment in AA4. Nor have they accounted for an accelerated customer or network deployment of batteries throughout the network in light of reducing prices as the consumer market rapidly matures.

Overall, the forecast outcomes and approach are still only an input to the planning process and remains disconnected from feedback mechanisms to incorporate the benefits from the initiatives that have previously been, or will be, implemented by Western Power. Without this feedback mechanism in place as part of the network planning or business case benefits capture process, it is unlikely that the benefits of flagship programs such as the AMI rollout (which relies on the avoided network augmentation value from enabling flexible tariffs – and an aggressive uptake by consumers) or Project Symphony (which is designed to orchestrate customer DER to more dynamically manage

[8] Increased energy storage will increase total consumption due to the round trip efficiency losses associated with charging, storage and inverter losses. Typical round trip efficiency for storage systems range from 80% to 95% - noting that comparisons need to account for configuration (AC coupled vs DC coupled). This would result in 5-20% additional energy consumption for each unit of energy supplied from storage – much of this would be sourced from co-located solar PV installations. .

the network loading, stability and utilisation) will be realised by Western Power for customers in the immediate term.

As the impact of the forecast on the CAPEX program is limited to the LV and MV components of the network downstream of the zone substation, the impact on the CAPEX program is assessed in the distribution augmentation CAPEX evaluation in section 3.

3.0 DISTRIBUTION GROWTH

3.1 Summary

The drivers for reassessment of distribution growth CAPEX in the Revised Proposal by Western Power are based on the update to the demand forecast to account for heat wave loading, changes to market information and a re-evaluation of capacity reinforcement needs on the MV and LV networks (i.e. on the customer side of the zone substation).

At a detailed feeder level (I.e. beyond the spatial demand forecasts provided for each substation) Western Power has provided modelling to explain the rationale behind their proposed increase in distribution growth CAPEX in the Revised Proposal, which includes:

- The need to consider distribution capacity expansion to manage legitimate issues resulting from the Christmas 2022 Heatwave (Christmas Heatwave), the impact of EV uptake and potential extreme temperature events over AA5.
- Scope definition and timing through more transparent and logical models and explanations for the treatment of distribution asset forecast over-utilisation under different scenarios.
- Consideration of some alternative solutions such as line switching and ongoing, but not yet conclusive, investigations into non-network solutions, however, the qualitative assessment to date remain at a very high level.
- Consideration of deliverability constraints, including limiting the extent of the revised distribution growth program to what Western Power determines to be realistically deliverable in AA5.

3.1.1 Key Concerns

We do however have four key concerns regarding the efficiency and prudency of the proposed expenditure that mean that we are not satisfied that Western Power’s Revised Proposal for distribution growth would reasonably satisfy the NFIT. These are:

1. **Service standards**: There is no explanation of why the additional expenditure is required for Western Power to maintain its service standards. The proposed $115.6 million is to replace or address all MV feeders and DSTRs that Western Power has forecast to be over-utilised in AA5. However, no linkage is drawn between this overutilisation, and how this may result in Western Power not being able to meet its service standards, and to what extent this overutilisation needs to be addressed by capital works to maintain these standards.
2. Accepting the risk of managing the network reliability within the minimum service obligations for the feeder type does not appear to have been considered as an option.
3. **Operational solutions:** Consideration of whether operational solutions such as demand management as opposed to capacity expansion AUGEX have not been clearly explored. The demand management capabilities as a result of the AMI program, customer DER enablement and Project Symphony learnings could be deployed more rapidly to reduce the need for network augmentation to manage and/or meet service standards, but it is not clear if or how these have been factored into Western Power’s distribution growth considerations.
4. **REPEX trade-off**: There is limited evidence of reprioritisation across other CAPEX categories. In particular, the works proposed represent a replacement of metro network assets with the purpose of increasing the capacity of the network (consequently categorised as distribution growth). However, there has been no adjustment to account for ‘augmentation driven’ replacements such as uprated distribution transformers, reconfiguration of feeders, switching improvements or reconductoring existing overhead lines with higher rated conductor (which may also bring forward the undergrounding opportunity and improve the business case for undergrounding works in OH areas).

5. **Augmentation scope and costs**: Western Power's augmentation costs per km are at the higher end of expectations – especially when averaged across a program. This is because augmentation for 'organic' load growth (i.e. from existing customers) is more frequently addressed through lower capital cost options than constructing new feeders. These include additional or uprated distribution transformers, reconductoring lines with higher rated conductor and establishing new 'normally open' ties between adjacent feeders/zones to improve switching options to rebalance loads between feeders/zones during peak/emergency events.

In summary, we recognise Western Power's justification and consideration of additional demand drivers – which will affect its distribution network over AA5.

Engevity is unable to conclude from the modelling provided that the expenditure is required to meet Western Power's reliability and service obligations or that Western Power has adequately considered options to reallocate risk within the total CAPEX allowance approved by the ERA in its draft decision. For this reason we have adjusted the both the incremental and base CAPEX forecasts to reflect that 12 per cent of the feeders forecast in 2021 are no longer required under the proposed 2022 forecasts.

In total we recommend a downward adjustment of $86.5 million to the expenditure sought in Western Power's Revied Proposal, resulting in a recommended substitute forecast of $274.5 million in total direct CAPEX for distribution augmentation.

Table 4 – Engevity Recommended Adjustment for Distribution Augmentation

Distribution Augmentation Program	Western Power AA5 Forecast Expenditure – Engevity Recommendded					
	Yr1	Yr2	Yr3	Yr4	Yr5	**Total**
ERA Draft Decision	59.6	49.9	44.7	47.3	44.0	**245.4**
Western Power Revised Direct CAPEX	67.5	61.5	68.1	78.0	85.8	**361.0**
Incremental Capex for Revised Proposal	7.9	11.6	23.4	30.8	41.8	**115.6**
Substitute Forecast						
ERA Draft Decision	59.6	49.9	44.7	47.3	44.0	**245.4**
- 12.2 per cent Draft Decision Scope Calibration	(7.3)	(6.1)	(5.5)	(5.8)	(5.4)	**(30.1)**
Adjusted Base	*52.3*	*43.8*	*39.2*	*41.5*	*38.6*	*215.3*
Additional Feeders	3.5	5.1	10.3	13.5	18.4	**50.7**
Additional Distribution Transformers	0.6	0.8	1.7	2.2	3.0	**8.4**
Adjusted Incremental	*4.1*	*5.9*	*12.0*	*15.7*	*21.4*	*59.1*
Engevity Recommended	**56.4**	**49.7**	**51.2**	**57.2**	**60.0**	**274.5**
Adjustment	*(11.1)*	*(11.8)*	*(16.9)*	*(20.8)*	*(25.8)*	***(86.5)***

Source: Engevity Analysis

3.2 Western Power's initial proposal

Distribution augmentation is referred to in the Western Power AA5 proposal as the distribution growth regulatory category. Western Power's initial AA5 proposal included $245.4 million in direct CAPEX, representing an increase of $32.4m (12.8 per cent) in net CAPEX in comparison to the AA4 period.

Table 5Table 6 - - AA5 Expenditure and Scale – distribution Augmentation Program [$m real at 30 June 2022]

Distribution Augmentation Program	Western Power AA5 Forecast Expenditure – Engevity Proposed					
	Yr1	Yr2	Yr3	Yr4	Yr5	Total
Western Power Proposed Total CAPEX [631]	*187.0*	*176.3*	*170.9*	*175.4*	*164.6*	*874.3*
Western Power Proposed Direct CAPEX [632]	59.6	49.9	44.7	47.3	44.0	245.4
Adjustment	-	-	-	-	-	-
Engevity Recommended Direct CAPEX	59.6	49.9	44.7	47.3	44.0	245.4

3.3 ERA's draft decision

Our assessment of Western Power's initial proposal of $245.4 million direct CAPEX for the distribution growth category was that it was broadly consistent with AA4 levels and therefore no specific adjustment was recommended. The initial proposal was based on demand forecasts that predated the incorporation of the Christmas Heatwave into Western Power's peak demand forecasting.

Our recommendation was that ERA approve the initial proposal for distribution growth CAPEX, subject to provision of further information to establish that the proposed expenditure aligns to the NFIT by demonstrating that it:

- Captures realisable economies of scope and scale
- Considers a range of alternative options
- Considers EV uptake and other likely impacts on load forecasting
- Includes a breakdown of projects associated with customer driven and capacity expansion distribution growth AUGEX
- Considers project deliverability and staging options

The ERA did not amend Western Power's distribution growth expenditure on the basis that it was similar to AA4 actual expenditure, although noted that it expected Western Power to provide update customer and demand forecasts in response to the draft decision.

3.4 Western Power's Revised Proposal

Western Power's Revised Proposal includes an additional $115.6 million in distribution growth to address the impacts of three key drivers that have emerged since the original proposal. These drivers are:

- **The 2021 Christmas Heatwave**, which has impacted the peak demand forecasts in Western Power's demand forecasts.

- **An independent report into the Christmas outages** (the Shepard Report or IRCO) resulting in several recommendations to improve forecasting, particular to account for the impact of future extreme temperature events due to climate change.
- **The impacts of the forecast uptake of EVs in the SWIS** (prepared by AEMO and the CSIRO), being explored by Western Power in conjunction with EPWA.

Western Power's new demand forecasts and demand considerations have resulted in higher forecast over-utilisation rates of distribution Transformers and MV metro feeders at ZSS. Western Power's $115.6million addition to distribution augmentation requirements in their Revised Proposal is intended for the capacity expansion works required to manage the additional demands on its metro network in AA5.

Table 7 - Western Power revised distribution growth proposal (Direct costs, real)

Expenditure category	Initial Proposal	ERA Draft Decision	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 revised
Growth	245.4	245.4	67.5	61.5	68.1	78.0	85.8	361.0

3.5 Analysis of Revised Proposal

The drivers behind Western Power's reassessment of their distribution network's capacity and their subsequent analysis appear reasonable in isolation. However, we have key concerns about how this analysis has translated into the additional volume and cost of distribution assets targeted for augmentation in the Revised Proposal, particularly in regard to:

- the extent to which the proposed capacity expansion works are necessary to maintain Western Power's service obligations
- whether alternative operational solutions have been sufficiently considered and accounted for
- consistency of unit rates used for feeders
- whether reprioritisation has occurred to determine the need for this additional expenditure, particularly an expected double up in distribution REPEX and AUGEX.

As a result, we find that the revised distribution growth proposal does not meet the NFIT. Further information is provided in the following sections.

3.5.1 Breakdown of revised growth CAPEX

The additional $115.6 million in distribution growth CAPEX proposed by Western Power relates to the management of the additional MV feeder and distribution transformer issues that are expected to arise from demand forecast updates due to the Christmas 2021 heatwave. That is, to manage issues on an additional 147 transformers and 74 MV feeders over and above those included in the initial proposal.

Western Power has also requested the application of the IAM to the distribution capacity expansion category to manage uncertainty of the impacts of EV uptake and extreme weather events – the consideration of which is outside the scope of this report.

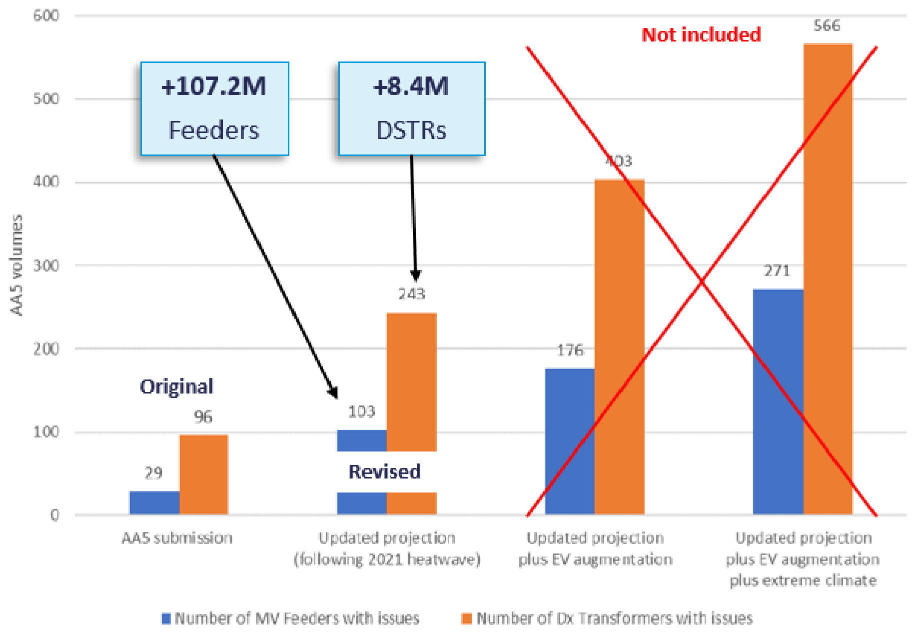
The ability of Western Power to exclude the large 'incremental changes' for EV and extreme weather scenarios with high uncertainty – illustrates the level of flexibility that Western Power has across its total capex program.

Western Power has demonstrated that it is preparing for a transition of its network but has not yet established what that means for the traditional planning and business case approaches. The relatively flat forecast across much of the network, Western Power's large scale transition initiatives and historical investment in enabling technologies for more granular control of demand, export and co-ordination of customer DER means that these solutions should be applied first in planning decisions. Only then is it appropriate to embark on an extensive augmentation program at the customer end of the network. In all cases, network investment should not inefficiently 'crowd out' customer choices to co-invest in DER technologies to meet their electricity supply needs.

The majority of the addition $115.6 million in the Revised Proposal is to address issues with MV feeders ($107.2M), with the remainder is allocated to manage loading on distribution transformers ($8.4M).

Figure 11 below summarises the cause for additional distribution CAPEX proposed.[9]

Figure 11 – Forecast MV Feeder and Distribution Transformer Count under different planning assumptions.



Source: Engevity mark up of Western Power Revised Proposal Figure 5.3

3.5.2 Need

Western Power's update of its demand forecast following the Christmas Heatwave is considered reasonable. Such events often serve as a real-life test of actual network capability to meet peaks in demand at both a local level and a system level. Long heatwaves can demonstrate what the current peak demand of customers may be, as opposed to what may have historically been experienced[10] or expected in previous forecasts. It is important to recognise that the peak demand will:

- Exclude any load that was not supplied during the peak event due to outage, and,
- Reflect the operating practices, management response and co-ordination of customer DER that was deployed during the event.

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9 Revised AA5 Proposal, Western Power, 15 November 2022, p. 63

10 The latent demand occurs because customers install additional split system refrigerative, inverter driven air conditioners (which are more energy efficient at part loads, naturally diversify demand by cycling up and down as required independent of other air conditioners. On 'normal' summer days, these operate at part load (where they are more efficient) and largely out of synchronisation with other units on the same feeder – providing significant diversification of load. During heat waves, the temperature of the building material itself gradually heats up – requiring the air conditioner to work harder (at a less efficient duty point) to hold the set temperature inside a house. Over the course of 3-4 consecutive days, this becomes the state at all premises on the feeder – resulting in all air conditioners operating in synchronisation and operating at a less efficient duty point. Both direct control (e.g. Energex PeakSaver or SAPN load control devices) and customer communications during heatwaves could target this education (e.g. turn off the bedroom AC during the day and watch cricket in the living room, cook on the barbie to keep the heat out of the kitchen)

The rapid presentation of customer DER during AA4 does support the view that Western Power had limited ability to actively manage customer DER during the Christmas 2021 heatwave. However, we also note that the AMI, SPS, Project Symphony and Customer Management System Investments over AA4 and AA5 mean that significant improvements in communications, operational response and customer DER, as well as potential emergency connection/disconnection orchestration would increasingly deliver benefits to manage both local and system peaks on the network. This effect would be compounded as the volume of storage and EV's at the customer end of the network allow customers to manage their own reliability and/or provide greater network flexibility during periods where the Power System is under stress.

These technologies also provide the ability to absorb significant volumes of charging energy at other times to significantly improve the utilisation of the existing network capacity on the vast makority of days each decade which are not subject to critical events. Higher overall utilisation of assets means that infrastructure costs are notionally spread across more energy throughput – increasing energy forecasts and reducing prices per kWh for a fixed RAB value.

An event such as the Christmas Heatwave and its resulting outages are an appropriate trigger to reassess capability, configuration, loading and condition of distribution network assets – and evaluate the available augmentation options.

Similarly, the additional impacts of EV uptake and extreme weather events are prudent concerns for Western Power to investigate in their planning scenarios. Both of these drivers are likely to drive increases in asset loading over the coming years.

To assess these factors Western Power has built on independent forecasts of EV uptake and extreme weather events to determine the potential need for additional capacity expansion works, including:

- EV uptake forecasts for the SWIS from AEMO and CSIRO, in conjunction with Western Power.
- Probability of extreme temperature days in an RCP 4.5 climate scenario determined by CSIRO, as a result of recommendations from the Shepherd Report[11]

However, Western Power states that the impacts of these additional scenarios have been excluded from the additional $115.6 million proposed distribution augmentation CAPEX, stating that the extent of work required to manage these additional two scenarios would present both a deliverability and reprioritisation risk.[12]

> *"Delivery of all three incremental changes (incorporate summer 2022 heatwave, extreme climate scenarios, and electric vehicles) presents a delivery risk and prioritisation issue for Western Power.*
>
> *Therefore the requested investment is equivalent to incorporate updated forecasts from the summer 2022 heatwave only, in conjunction with application of the investment adjustment mechanism to allow for flexibility for extreme climate scenario planning and electric vehicle adoption."*

We recognise that the impact of these three drivers, the Christmas Heatwave, EV uptake and extreme temperature days represent a prudent trigger to re-examine the current and future capability of Western Power's distribution network.

However, capacity expansion of the network is not the only response available to manage the increases in demand as a result of these drivers. Operational responses such as pre-summer phase balancing (better enabled through AMI data), as well as Demand management plays a vital and

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[11] Independent Review of Christmas 2021 Power Outages, Michelle Shepherd, March 2022

[12] ERA39 – CAPEX Increase - distribution Capacity Expansion – Overview and Explanatory notes for ERA consultant (62186510), Western Power, November 2022, p. 4.

rapidly increasing role in balancing load and network utilisation such that network assets can be efficiently sized and costs to customers are minimised.

3.5.3 Scope Definition

Western Power has provided modelling and explanation that sets out the scale of feeder and distribution transformer issues that it considers should be addressed as a result of the Christmas Heatwave, EV uptake and extreme weather events.

Engevity notes that the model provides sufficient transparency over how the specific constraints have been identified but reiterates that the model does not appropriately account for the deployment of technology innovation (e.g. AMI, Project Symphony), demand management or operational solutions to reduce peak demand. If these were included in the analysis, the scope of Western Power's overutilisation issues in its MV feeder and distribution transformer asset bases would be substantially reduced.

Western Power is proposing an additional $107.2 million in MV feeder augmentation and $8.4 million in distribution transformer investment due to projected overloading after incorporating the 2021 heatwave peak into its forecasts. The incremental issues identified by the EV and extreme weather events scenarios have been excluded from the revised CAPEX proposal on the basis of deliverability, indicating that Western Power:

- is recognising more acute resourcing issues for some types of work over AA5
- will need to adopt a strong risk based prioritisation approach to effectively manage service outcomes within the resources that are available to the WA market
- maintains sufficient flexibility in the proposed CAPEX program to accept the risk of EV and extreme weather uncertainties on the distribution network.

We remain concerned that the limited consideration of the alternative options at this stage of the regulatory process effectively provides an informal contingency within the overall CAPEX allowance resulting from the high uncertainty in planning scenarios and limited development of regulatory investment justification. Western Power demonstrates prudency in addressing the imminent, higher probability issues with a sensible view to monitor the need for further investment throughout the AA5 and AA6 period.

Compounding Scope and cost growth

This is exacerbated by large increases to both the unit rate (75 per cent increase from $400k/km under Western Power's reference NP23-AA5 to $700k/km) for feeders, as well as the scope of the average feeder augmentation (50 per cent increase from 5km to 7.5km per 4 feeder substation) over Western Power's previous planning assumptions – significantly exceeding the 6.5km and $4.5m that was noted by Western Power for the new "MH & WAI ACR works" reference project.

The higher unit costs are based on the capex from the accelerated 'ACR' program that followed as the immediate capital response to the heatwave. Therefore we consider that the unit costs used by Western Power, as well as the required scope is significantly overstated for a program planned and delivered over five years. Importantly, the ACR work business case excludes a range of non-network alternatives due to the timing need for that project. (e.g. Battery solutions were deemed technically unviable because they were assumed to have a 12 month lead time and would not be in service prior to summer 2022-23). The time constraints are not applicable to works covered by additional CPEX sought by Western Power.

For these reasons we do not consider that the accelerated nature of the ACR work represents a reasonable reference project for a program that is planned to be delivered and refined over a 5 year period – and weighted towards the end of the period.

Table 8 - Comparison of Western Power feeder unit rates and scope assumptions from the same spreadsheet

	WP Proposed 'FDR Summary' Sheet	Reference Project **'Readme' Sheet** MH & WAI ACR	Calculated 'per feeder' rate **'ZS List'** Sheet	Base Forecast 'Readme' Sheet 'NP23-AA5'
$m/km	0.7	0.7	-	0.4
km cable per sub	**7.5**	**6.5**	**-**	**5**
No. feeders per sub	4	4	4	4
$m/sub	5.3	4.5	3	2.0
$m/feeder	**1.33**	**1.12**	**0.75**	**0.50**
% increase in cost	75%	49%	123%	-
% increase in scope	50%	50%	73%	-
% Total increase over 'NP23-AA5'	**163%**	**123%**	**49%**	-

Source: Western Power, *ERA39 - Capex Increase - Dx Capacity Expansion - S2022 metro ICAT snapshot for AA5 Draft Decision response.xlsx - 1 Dec 2022*

Note: The total increase is calculated from the compound effect of both cost and scope increases. i.e. 100% x 175% x 150% = 263% Less the original 100% to give a 163% total increase

Again, the over scoping and exclusion of potential network transformation benefits provided by alternative and emerging technologies raises significant concern over a period where significant investment by Western Power and customers in these technologies is planned.

3.5.4 Modelling and analysis

Western Power has provided relatively detailed models and explanatory notes to demonstrate how it has identified the assets targeted for augmentation in its Revised Proposal.

The models contain cost assumptions that tend towards the upper end of typical expectations, asset loading limits, and evidence of prudent filtering logic to determine assets to target for augmentation. Western Power has actively mitigated the duplication of demand increases arising from the combinations of the updated demand forecast, EV uptake and extreme temperature events.

The models are based on forecast peak demand from Western Power's updated demand forecast, which has incorporated and been weather normalised, consistent with prudent network planning approaches. However, the spatial forecasts do not provide detail on how it is derived beyond a note citing general sources 2021 demand forecast, economic factors, spot loads etc. This makes it difficult to scrutinise what assumptions underly each substations forecast demand growth rate.

In summary the models demonstrate:

- **A total of 103 feeders are forecast** to reach over >80 per cent utilisation (representing Western Power's target to commence augmentation planning) and have a positive demand CAGR in AA5 based on current demand forecasts (excluding impacts of EVs and extreme weather events).

- **Western Power does not flag feeders with >80 per cent utilisation and a negative CAGR** as issues, allowing these assets to 'sweat' and return to utilisation bounds over time.
- **272 distribution transformers are flagged for replacement**, based on a loading limit of 130 per cent.
- **The unit costs used for MV feeders ($0.7M/km) is at the upper end of expectations and distribution transformers ($50-$72k) are broadly consistent with typical industry figures** for pole top transformers, or smaller ground mount kiosks. Concerns regarding the scope and cost increases for feeders are detailed on the previous page.
- **The EV load model looks at multiple uptake and use scenarios**, granular spread of customer and charging behaviour and technologies, and translates results to additional load on the network rationally. Western Power uses the AEMO step change scenario projection of 200,000 EVs in the SWIS by 2027. High uncertainty remains in the scale and timing of EV uptake in WA (as seen by the large spread in the CSIRO planning scenarios).
- **The extreme weather events analysis** looks at the impact of more severe extreme temperature events on Western Power's network, as expected to occur under CSIRO RCP 4.5 climate change scenario. As such, it is not intended to assess the impact of, or plan the network for, extreme weather events generally, such as cyclones or fires.
- **This analysis appears to avoid double up with BAU**, it is in fact stretching the extreme demand loading (i.e 10 PoE) on the network by further increasing demand associated with temperature increases beyond what was experienced in the Christmas Heatwaves.
- **By regression analysis Western Power has found a demand-temperature elasticity to be 4 per cent per degree** based on a 10 PoE view of the impact of extreme temperatures over the next 10 years. It is typically efficient for networks to plan for 50 PoE peak demands and have operational contingencies established to respond to demands up to the 10 PoE in the years that they do occur.
- **We note again that Western Power has not included the CAPEX arising from this modelling** in its revised CAPEX proposal (i.e. the EV and extreme weather).

In total, modelling of Christmas Heatwave, EV uptake and extreme weather appears to be a reasonable upper-limit sensitivity case for technical purposes. However, it is based on peak demands that do not transparently incorporate the impacts of improvements to operational demand management, stranding risk for long life assets or program deferral potential over AA5. Western Power's 2022 public Network Opportunities data identifies deferral options and alternatives that may reasonably contribute to reductions in period.

3.5.5 Timing

The proposed timing of Western Power CAPEX is consistent with modelled asset overload based on the Western Power forecast. The process is transparent.

Western Power is already undertaking the 'minimum viable works' it deems necessary to prepare its metro network for this Summer (2023). This is reflected in the Accelerated Capacity Reliability (ACR) works business case put forward in June 2022.[13]

As a result, the $115.6 million proposed is intended to manage the longer term requirements of the distribution network over AA5, in addition to ACR works that are currently ongoing.

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[13] ERA39 - CAPEX Increase - distribution Capacity Expansion - IAR145823 – Business Case for Accelerated Capacity Reliability (ACR) works 2022 (60372801), Western Power, June 2022

The additional distribution capacity expansion CAPEX is back-ended in the AA5 period, in line with the intention of the ACR works and implications of the increasing asset utilisations over the period.

3.5.6 Risk Management

We could not identify how Western Power considered whether the proposed capacity expansion works and associated CAPEX is required to meet Western Power's service obligations and could be prioritised to the higher risk regions in AA5. Western Power is required by the Technical Rules to design the distribution network to 'supply the maximum foreseeable load' in its service area[14], but has not provided an explanation linking the volumes of assets targeted for augmentation with the need for Western Power to maintain its reliability or power quality standards in suppling its customers. Under unusual and extreme events – such as the 2021 heatwave – the network should aim to minimise the loss of supply within the prudent and efficient capacity, systems and operational capability that is available at the time. Under these conditions, an economic degree of supply interruption and plant operation at cyclic /short term ratings should be expected – this does not appear to have been incorporated into the analysis.

We recognise that 107,000 Western Power customers experienced an outage during the Christmas Heatwave event and that the outages were exacerbated by Western Power's operational protocols limiting the ability to restore power during the co-occurring bush fire and heat wave conditions. However, the recommendations of the Shepherd Report focus first on operational response, customer communication and planning improvements for extreme temperatures. It does not cite capacity augmentation as the preferred, or central, solution for managing outages and building resilience for these events.

Ultimately, this event does not represent the 50 POE demand on the network that Western Power uses for the purposes of distribution network planning. We also recognise that the impacts of the Christmas heatwave have been normalised in Western Power's updated demand forecast, however the resulting feeder and transformer overutilisations are not linked back to risks to customer supply and reliability.

Western Power's reliability performance in the Perth CBD and urban network has generally been strong over AA5 compared to historical performance.[15] Western Power has achieved its Urban and Perth CBD SAIDI and SAIFI SSBs for most years in AA4, and have exceeded their SSTs repeatedly.[16] Western Power has also undertaken work to improve urban reliability performance over AA5, from which it expects to see benefits from 2022/23. In its original proposal Western Power states that:[17]

> *"Trends show that performance is plateauing, which is consistent with industry practice. Low-cost investments to address reliability have been implemented and we are getting to a stage where customers are happy with their level of reliability and do not value additional investment to improve reliability."*

As a result, we consider that it would be more efficient to plan to 'sweat' certain assets identified for augmentation in the Revised Proposal rather than replace or augment them. This is because it would maximise the CAPEX allowance available to respond to uncertainty. The extent to which the replacements are needed to maintain customer supply and meet customer expectations remains poorly articulated and justified.

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[14] TECHNICAL RULES FOR THE SOUTH WEST INTERCONNECTED NETWORK, Western Power, 1 Dec 2016, Clause 2.6(a)

[15] Access Arrangement Information, 1 Feb 2022, Western Power, pp. 79-81

[16] Ibid.

[17] Ibid, p. 74.

Conversely, we also note that Western Power has not met the reliability standard in the Electricity Code[18] for its Perth CBD or urban network over the past four years and acknowledge that there are likely areas of the urban network where it is efficient to improve reliability. Such considerations are not discussed by Western Power in their revised distribution growth proposal.

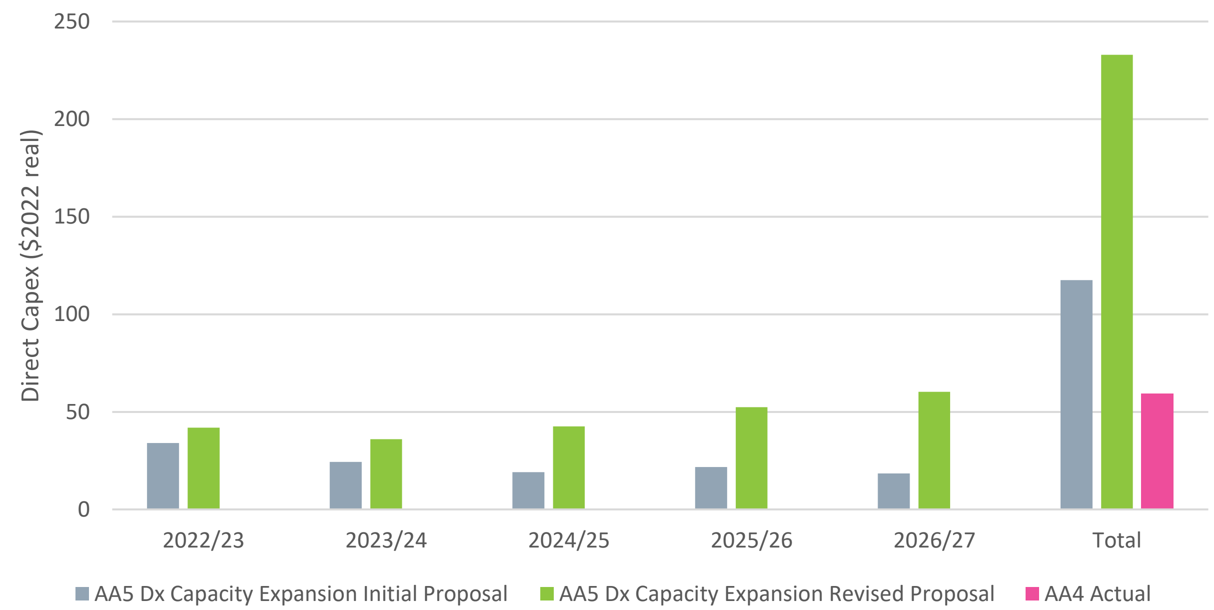
For its proposal to meet the NFIT, Western Power needs to demonstrate how the issues being mitigated by augmenting the volume of assets identified in its capacity expansion program are required to meet its service obligations. Without such information, there is a risk that assets are being replaced or augmented where there is not a defined need for Western Power to do so as a regulated network business.

3.5.7 Cost Efficiency

While the unit costs of augmenting the targeted assets provided in Western Power's models appear to be reasonable in isolation, there is insufficient evidence to conclude that the CAPEX required for these assets is not already proposed under different expenditure categories, or cannot be reduced to reflect the typical delivery synergies that arise from concentrating the new activities on a relatively small number of substations.

Western Power has not provided information on whether an overall CAPEX reprioritisation process has occurred. In particular, the Revised Proposal does not include any reduction to distribution replacement expenditure. The revised distribution growth proposal now includes 140km of new feeder replacement as capacity expansion AUGEX, and we would have expected at least a reduction in distribution REPEX categories such as conductor management.

Figure 12 - Distribution capacity expansion CAPEX comparison



Western Power has demonstrated the capability to reprioritise over $100 million in its SCADA program in its Revised Proposal. Western Power has also asserted that co-optimisation with the undergrounding program is possible but would have limited benefit. This was justified on the basis

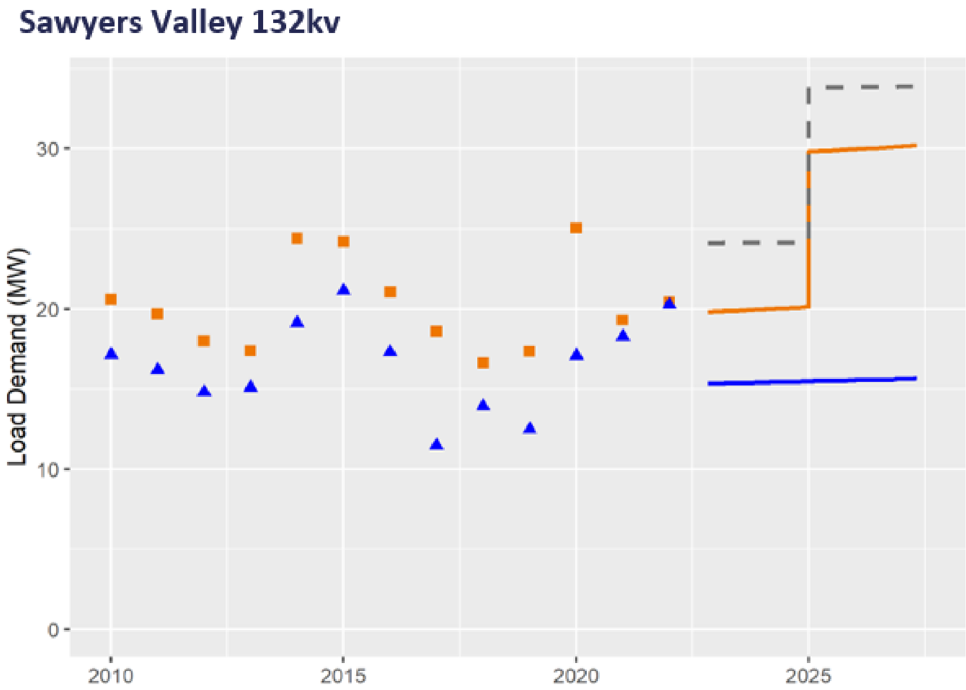
[18] Electricity Industry (Network Quality and Reliability of Supply) Code 2005

that the undergrounding program is optimised on the basis of LV asset lives and 'any overlap between [undergrounding and dx growth augmentation] would be coincidental.'[19]

While the total distribution growth CAPEX was relatively flat between AA4 and the AA5 proposal, the initial AA5 proposal for distribution capacity expansion AUGEX, $117.5 million was already 97.3 per cent higher than in AA4.[20] Western Power's Revised Proposal for capacity expansion AUGEX is 291.4 per cent higher than AA4 expenditure for a total of $232.9 million above AA4 levels.[21] This is a significant step change in capacity expansion expenditure, shown in figure 12 above.

In addition, the updated load demand forecasts for a number of the zone substations at which Western Power has identified feeder and transformer issues exhibit very high growth rates or step changes, as shown in figure 13 below.

Figure 13 - Example of step change in ZS load demand[22]



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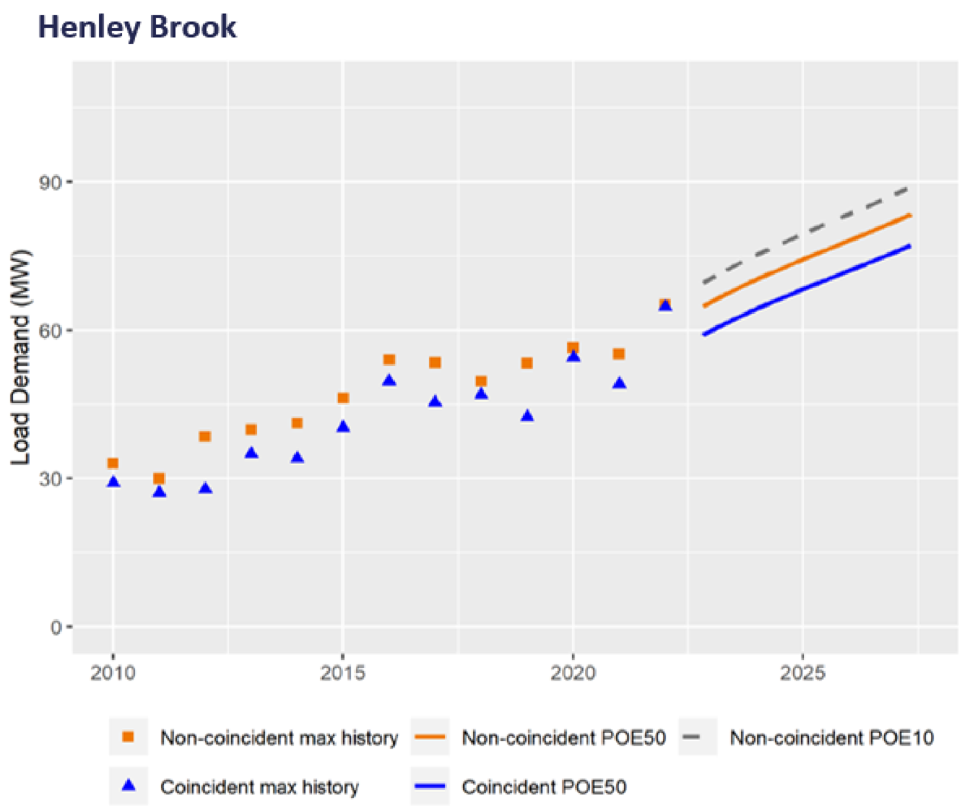
[19] Revised AA5 Proposal, Western Power, 15 November 2022, p. 61

[20] AAI - Attachment 8.1 - AA5 Forecast Capital Expenditure Report, Western Power, 1 Feb 2022, p. 61

[21] Revised AA5 Proposal, Western Power, 15 November 2022, p. 60

[22] Attachment 1.6 - Maximum demand forecasts (SUMMER) by zone substation (2021), Western Power, 15 November 2022, p. 120

Figure 14 - Example of high demand growth rate at ZS (>7 per cent)[23]



Issues caused by overutilisation of feeders and transformers relating to these substations are likely to be linked to the connection of a few large new customers (or large estate developments). They may also result from load transfers from other substations to create additional capacity as another point in the network. In cases where the growth is driven by new customers, part of the CAPEX would be met by capital contributions. When clarification was sought from Western Power, we were advised that all load growth for these works were organic and no capital contributions would be recoverable.

Notwithstanding this, our primary concern relates to the unit cost increases, along with scope increases that Western Power has proposed for feeders. We do not consider the revised distribution growth program cost assumptions are efficient.

3.5.8 Scope Efficiency

We do not believe the scope of the distribution growth Revised Proposal to be efficient because Western Power has not established that the work is required to meet Western Power's service obligations (this is discussed above). Insufficient evidence was provided to demonstrate that Western Power has appropriately considered operational solutions or technology alternatives that could reduce or defer the scope of capacity expansion works required, discussed further below.

3.5.9 Strategic Alignment

Western Power's intention to manage the changing demands on its network in response to the Christmas Heatwave and to account for the future impacts of EV uptake/extreme weather event scenarios due to climate change is strategically aligned with Western Power's internal strategy and external programs with which it is involved.

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[23] Ibid. p. 60

3.5.10 Options Analysis

Western Power has provided evidence that is has considered some alternative options to managing distribution feeder and transformer over-utilisation to network augmentation. In particular, the ACR business case includes consideration of load switching as an operational solution to manage high demands. Similarly, the ACR business case also notes that Western Power is continuing to consider non-network solutions at a limited, qualitative level to manage the impact of events like the Christmas Heatwave.

However, there is no clear discussion of how operational or demand management solutions have been considered as an alternative to the very large $115.6 million of additional capacity expansion AUGEX proposed in the Revised Proposal. Therefore we can only consider the Western Power forecast as a 'worst case' rather than 'most likely' estimate of efficient costs.

This is a key concern in the context of the very large step change already sought for this category, as Western Power's AA4 investments in Project Symphony, full AMI rollout in AA5 and forecast customer uptake of DER provides significant opportunity to manage demand operationally through programs and technologies being currently rolled out by Western Power or its customers. In particular:

- Demand management capabilities as a result of Western Power's large AMI program and Project Symphony could help reduce the need for network augmentation to meet service standards, but these are qualitatively excluded as unfeasible due to 12 month lead times for batteries in the ACR business cases which ultimately favour the Western Power's distribution growth expenditure requirements.
- The AMI program will help Western Power to understand the voltages and power flows on its feeders and transformers and more efficiently utilise its assets in concert with customer DER. Flexible Tariffs are expected to relocate demand from the peak and enabling the remote connect/disconnect capability of AMI brings benefits to manage load and exports on any feeder at a very granular level.
- Similarly, the impacts and opportunities of customer DER is not discussed. Customer BESS and EVs are not included in the revised energy forecasts.[24]
- customer communications can also be used to influence demand profiles during peak events, which have not been discussed.
- There is also limited consideration evident of active evaluation of phase balancing and load transfer between zone substations and feeders. We note that DNSPs in QLD/SA/NSW have integrated hot water switching and/or peak smart A/C capabilities into their networks to manage demand events such as heatwaves. In some states, portfolios of over 500MW (in the order of 12.5 per cent of the SWIS peak) of diversified network controllable small customer load is available under these initiatives.

As a result of these factors – and the concerns that we have expressed over the forecasting process itself, Western Power's Revised Proposal for distribution growth is likely not to be the most efficient solutions to the issues identified.

3.5.11 Delivery Model

Western Power has not provided any detail on delivery models in their Revised Proposal beyond its previously quoted concern over the deliverability of the three scenarios in parallel (heatwave,

[24] Energy and Customer Forecast Report, Western Power, Nov 2022, p.10

Climate, EV's). We note that the business has considered the deliverability of the revised program and specifically has highlighted deliverability risks as a reason to restrict scale of works proposed.

Less capital intensive solutions, staged projects, customer or third party led non-network solutions alongside OPEX responses would further manage delivery risk and alleviate pressure on Western Power Resources over AA5

3.6 Conclusion

Engevity has reviewed the additional information provided by Western Power in support of its revised distribution augmentation CAPEX forecast. We found that:

- **The models, information and supporting information were of an improved quality**, with greater transparency provided to test and validate the approach claimed by Western Power
- **The feeder forecasting approach lacked consideration of operational measures, demand management or greater control** via AMI data and remote connection/disconnection capability to manage demand within the constraints of the existing plant capacity. (for 'native' growth in demand arising from existing customers)
- **Unit cost and scope assumptions for feeders are likely to be significantly overstated in the modelling.** Overall, Western Power has increased the cost per feeder by 163 per cent over its previous planning assumptions. This includes a 75 per cent increase in the unit cost for km and a 50 per cent increase in the scope assumption for the distance of cable that is required. The source of the increases is the adoption of a new reference project in the accelerated ACR response to the recent heatwave. This did not consider non-network options due to the timing constraints for delivery prior to the next summer.
- **The 80 per cent augmentation threshold for feeders should be challenged** because there remains the ability to apply short term cable and line ratings, or recalibrate the rating parameters (temperature, wind speed, soil temperature, conductor height etc) to the actual operating environment. This would enable network funded augmentation investment to be approached more cautiously and deferred for as long as possible in an environment of flat or declining system demand.
- **The business cases provided for the augmentation works qualitatively dismiss non-network solutions** (such as batteries) on the basis that they have a 12 month lead time and would not be available for the in service date requirement for an urgent project. Batteries, DER orchestration or leveraging AMI capabilities are not considered as an option for all other projects that do not have an urgent time constraint. As with Western Power's other financial analysis, the value of the real optionality embedded in shorter life assets or short term solutions has not been assessed in investment decision making.

As a result, we do not consider that Western Power's Revised distribution augmentation CAPEX is prudent and efficient and therefore it is not reasonably expected to satisfy the NFIT.

We do recognise the need to address some of the higher risk overloads that were observed during the heatwave, but these must demonstrate that the probability weighted reliability performance (typically averaged over five years to smooth inter year volatility) would fall below Western Power's service level obligations.

Without making this critical service level – investment calculation, transformer and feeder overloads that may occur once every ten years are contrary to the metro customer feedback that there was a low willingness to pay for reliability improvements. Augmentation may still occur but it should be based on a quantified assessment of risk, investment options and reliability obligations. As a result, augmentation would be more likely in higher density, weakly meshed or radial parts of the network where the reliability cost per minute off supply is much higher and options to switch to alternative supply are limited or non-existent.

3.7 Recommendation

From our review **we recommend that the $115.6 million additional distribution augmentation CAPEX sought by Western Power in its Revised Proposal is not approved** on the basis that it does not adequately consider alternative to network investment, benefits from AA4 transition programs or AA5 programs providing greater LV network visibility, monitoring and control – alongside greater orchestration capability for customer DER.

We recommend an alternative allowance of $59.1 million[a] for the incremental capex sought by Western Power that is reasonably likely to satisfy NFIT.

We also recommend a downward $28.8 million[b] adjustment to the $245.4 million[c] Draft Decision allowance to account for the proportion of the original program that was observed to be no longer required in the Western Power analysis when reviewed after 1 year.

This has been derived as follows:

- Western Power Proposed **$115.6 million[c] in incremental distribution augmentation CAPEX** above the Draft Decision allowance to reflect additional updated planning forecasts.
- Western Power identifies **that $8.4 million[d] of this amount is associated with distribution transformer upgrades, leaving $107.1 million** for feeder augmentation.

  $115.6 (Total) - $8.4m (Distribution Transformers) = $107.1m

- **Western Power identifies that the new reference project incurred $4.5m for 6.5km of cable as the source for its revised $0.7m/km unit rate** and represents an increase of 75 per cent over its previous assumption of $0.4m per km.
- **The modelling applies a higher still (7.5km) volume of cable** in its standard assumptions, representing a 50 per cent increase over the previous reference project and 15.4 per cent[25] increase over the new reference project. Therefore, we recommend reducing the total by 15.4 per cent to align with Western Power's nominated reference project.

  $107.1m (Feeders) x -15.4% = -$16.5m (adjustment)

  $107.1m (Feeders) - $16.5m = $90.6m (cumulative)

- **Less 12.24 per cent calibration factor for the forecasting process** based on the overstatement of 12 feeders removed from the 2021 forecast of 98 feeders in the equivalent 2022 feeder forecast

  $90.6m x -12.24% = -$11.1m (adjustment)

  $90.6m - $11.1m = $79.5 (cumulative)

- **Less a one year deferral** to adjust for timing, estimation and limited consideration of the impact of demand management, improved network visibility and remote connection/reconnection control on feeder loading**.** Scaled down using a factor of 74.3 per cent ($79.5m cumulative for feeders /$107.2m original for feeders) to maintain proportionality with the cumulative total.

  -$38.8m (AA5 fifth year incremental cables expenditure) x 74.3% = -$28.8m (adjustment)

  $79.5m - $28.8m = $50.7m[e] (cumulative)

- **Add back Western Power's $8.4 million forecast of additional Distribution Transformer augmentation** to calculate the total additional distribution augmentation capex

[25] 1 additional km in scope assumption (7.5km less 6.5km) divided by the new reference project total of 6.5km

$$\$50.7m + \$8.4m = \$59.1m^{a}$$

This gives an additional $59.1m of distribution augmentation capex that Engevity considers to be prudent and efficient to address the issues raised by Western Power in its Revised Proposal. To capture the timing considerations, this should notionally be distributed across AA5 in proportion to Western Power's incremental expenditure.

For consistency, **the -12.24% forecast accuracy adjustment should also be applied to the base distribution augmentation CAPEX forecast** - as it has been developed using the same planning processes used for the 2022 forecast. This is outlined below

- **Calibrate the Western Power's $245.4m base distribution augmentation CAPEX** using the calibration factor (-12.2 per cent) observed from analysis of the changes between the detailed 2021 and 2022 feeder requirements

$$\$245.4m \times -12.24\% = -\$30.1m^{b}$$

In total we recommend a downward adjustment of $86.5 million[f] to the expenditure sought in Western Power's Revied Proposal, resulting in a recommended substitute forecast of $274.5 million in total direct CAPEX for distribution augmentation.

Table 9 - Recommended adjustment Distribution Augmentation CAPEX (Totals may not add due to rounding)

Distribution Augmentation Program	Western Power AA5 Forecast Expenditure – Engevity Recommendded					
	Yr1	Yr2	Yr3	Yr4	Yr5	**Total**
ERA Draft Decision	59.6	49.9	44.7	47.3	44.0	**245.4**
Western Power Revised Direct CAPEX	67.5	61.5	68.1	78.0	85.8	**361.0**
Incremental Capex for Revised Proposal	7.9	11.6	23.4	30.8	41.8	**115.6**[c]
Substitute Forecast						
ERA Draft Decision	59.6	49.9	44.7	47.3	44.0	**245.4**[c]
- 12.24 per cent Draft Decision Scope Calibration	(7.3)	(6.1)	(5.5)	(5.8)	(5.4)	**(30.1)**[b]
Adjusted Base	*52.3*	*43.8*	*39.2*	*41.5*	*38.6*	*215.3*
Additional Feeders	3.5	5.1	10.3	13.5	18.4	**50.7**[e]
Additional Distribution Transformers	0.6	0.8	1.7	2.2	3.0	**8.4**[d]
Adjusted Incremental	*4.1*	*5.9*	*12.0*	*15.7*	*21.4*	*59.1*[a]
Engevity Recommended	**56.4**	**49.7**	**51.2**	**57.2**	**60.0**	**274.5**
Adjustment	*(11.1)*	*(11.8)*	*(16.9)*	*(20.8)*	*(25.8)*	***(86.5)***[f]

4.0 AA5 CAPITAL ALLOWANCE - RISKS

4.1 Summary

Western Power incorporated the reduction in CAPEX from the ERA Draft Decision but highlighted a range of risk and service performance tradeoffs that it saw would result from curtailing the CAPEX program. Our review of the additional information provided found that Western Power:

- **did not address our prior concerns relating to failure forecasting bias (overstated), risk quantification or portfolio prioritisation concerns.** These are key to both efficient forecasting and in-period reprioritisation of works across the portfolio based on consistently quantified risk.
- **has not demonstrated the consideration of process improvements that mitigate risk** that would facilitate more granular and consistent quantified risk calculations, condition analytics and continuous reprioritisation – as have been implemented by industry peers (and how these could mitigate the perceived risk)
- **sought to transfer the Asset Management risk arising from accepting the ERA' Draft Decision to consumers** via lower service level requirements and higher internal evaluation of risk.
- **has not considered mechanisms available in the regulatory framework** such as deferral to AA6, including descoping or staging projects to minimise AA5 expenditure

Asset Management and System Performance Risks are solely owned and best managed by Western Power who retains control of decision making, forecasting and operational responses – as well as access to regulatory mechanisms to manage these risks.

As a result, we maintain our view that the initial proposal was not efficient and that the recommended reductions can be managed within the ERA's Draft Decision. We also do not consider that the associated adjustments are justified in relation to relaxing service levels to customers, asset failure forecasts or Western Power's proposed adjustments its risk levels – as they have not responded to our primary concerns outlined in advice supporting the ERA's Draft Decision.

4.2 Context

This section recognises how the risks associated with the reduced REPEX allowance can be more accurately quantified and the impacts mitigated. We also discuss the mechanisms available to Western Power Management under the WA regulatory framework which provide additional relief that may not be recognised in the more operationally focussed risk assessments that are employed for preparing regulatory CAPEX forecasts.

These risks must be considered at a portfolio level because much of the program is based on a certain volume of assets that have been calculated within Western Power's risk quantification tools and replacement planning algorithms.

The nature of replacement work is that there is almost always considerable short term flexibility in managing the replacement timing by deferring some individual replacements without experiencing a significant step change in the actual risk to reliability from year to year. This is simply because within a regulatory period:

a. **Risks are diversified across the replacement program by leveraging flexibility to reallocate the total CAPEX allowance** between individual assets based on risk, asset categories based on relative risk, augmentation and replacement based on actual demand growth, and between network and non-network needs.

b. **Where the existing asset remains in serviceable condition, and replacement is triggered by condition, there is minimal incremental risk posed by each additional year of**

operation. This is because the 'probability of failure' distribution for long life assets is relatively broadly distributed mathematically (e.g. a large standard deviation statistic) such that the probability of failure in any year is small and relatively constant over short to medium planning horizons.

c. **Condition Based replacement practices enable a relatively comprehensive view of individual asset condition**, allowing replacement planning to prioritise the highest risk assets/sites based on updated condition information from inspections, monitoring and defect logs – accompanied by assessments of the reliability value of energy not supplied.

d. **By prioritising the highest risk assets with demonstrable condition-based indicators of failure in the early years, and monitoring their condition on an ongoing basis,** there is a increasing likelihood that the condition of assts planned for replacement in the latter years are able to be deferred into the subsequent period on the basis of updated condition assessments.

Overall, the ongoing reprioritisation of the total capital expenditure portfolio over the course of AA5 to manage the risk within service performance requirements is the primary tool for Western Power Management to create value through its investment program.

There is a strong regulatory incentive for Western Power to offset risk through efficient innovation, find less capital intensive solutions and reduce the scope of the CAPEX based on more granular analysis of the available asset condition and risk information that becomes available during the period. This provides a degree of assurance that Western Power will seek to leverage these benefits for customers to avoid unnecessary, duplicated or inefficient investment in network assets for issues that customers choose to address privately with their own DER.

4.3 Important Clarification on 'Good Industry Practice' 'Best Industry Practice'

In relation to the asset and risk management we note that Western Power asserts at para. 82 of its Revised Proposal that its: *"…**risk-based approach** to asset management and investment governance reflects **industry best practice**".*

Western Power claims endorsement of the all-encompassing *'risk-based approach'* adopted by Western Power by referencing Engevity's prior observation that Western Power's

*"… capital governance processes and asset management processes align with **good industry practice**".*

For clarity, we note that Western Power's 'risk-based' approach as a whole is not considered to be best practice

This also applies to the much narrower and more qualified assessment [26]by Western Power's stage 2 ISO55001 assessor, Lloyds Register, quoted at para 83 of the Revised Proposal as:

> "Western Power has **a number of industry leading practices**, particularly in the areas of asset risk management and the 'line-of-sight' linkages to organisational objectives, as well as the optimisation and prioritisation of programs and projects"

Again, Western Power has misrepresented the phrase *'a number of industry leading practices'* by implying that it applies to the entirety of the ISO55001 accreditation. Whilst the business has achieved recognition that *some* of its *practices* are considered industry leading, accreditation to ISO55001 has been achieved by the majority of Australian electricity networks.

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26 This is because 'best practice' only exists when the individual strengths of all businesses in an industry as a whole are 'cherry picked' to establish an aspirational benchmark that has demonstrably been achieved somewhere – and should serve as a reasonable performance improvement target for other businesses to achieve..

As a result, ISO55001 accreditation is now a baseline expectation for Australian electricity networks. In comparison to a global cohort, Australian businesses have typically been aligning to structured Asset Management systems since the electricity market reforms of late nineties and PAS 55 (the UK predecessor adopted as the International ISO55001) since the late 2000's.

4.3.1 Limitations of consultant report conclusions

The conclusions in professional services reports must always be interpreted in the context of the service that was procured, the level of independence, access to information, any qualification or omission, and the specificity of the wording. To avoid duplication with other parallel/ complementary processes, manage confidentiality or obtain a more cost effective service, contracts often limit the scope, level of enquiry, strength of assurance or access to information.

To clarify, our endorsement was limited to Western Power's *processes* (i.e. the documented systems and governance structures used by Western Power and provided for review) and not the entirety of the end-to-end 'risk-based' *approach* – as this would require more detailed and invasive 'live systems audits' to:

- verify the correct and operation of Western Power's systems
- scrutinise the inputs, outputs, approvals and exceptions to verify the consistency of application for each of the key processes
- gain comfort over the mathematical/logical validity of the process
- Confirm that the *processes* have been implemented consistently and are applied consistently across the business.

An assessment of this nature was beyond the scope of our review and was not possible with the limited 'live' documentation or system access that was provided by Western Power.

4.3.2 Our view of Good Industry Practice for Australian NSPs

In the context of our review, **Good Industry Practice** simply refers to processes that have all the elements, approvals, controls and governance structures that would be expected in a similar industry comparator business.

Similarly, we note that **ISO55001:2014 accreditation does not denote best practice. Accreditation simply provides assurance that a business has met the 'minimum' standard for accreditation**. The standard anticipates that ongoing improvements and increasing asset management maturity over time will refine processes and lead to more effective, efficient, and value maximising investment decision making.

As ISO55001 accreditation is a compliance requirement for most Australian networks, our prior assessment that achieving and maintaining accreditation represents an appropriate minimum benchmark for **Good Industry Practice** for Australian networks.

4.4 Access Code 'Uncertainty' Framework

. The regulatory CAPEX allowance is set at a level that will not address *every foreseeable* risk (which would obviously overstate the CAPEX requirement, causing upward pressure on network prices), but is set at a level that is sufficient in total to address the *likely* risks that will present during the AA period.

This means that Western Power will need to efficiently reprioritise expenditure based on the new information on asset condition, emerging issues, and changing demand patterns throughout the period. The intent of setting a 5 year allowance is to incentivise efficient and dynamic investment in the network that can adapt to changing investment drivers within an AA period.

In practice, Western Power's Asset Management expertise and systems are designed to achieve just this. To identify the assets that need replacing/refurbishment and allow the others to remain in service to maximise the value that 'longer than average life' assets deliver to customers.

We consider the Draft Decision adjustments to forecast CAPEX reflect a prudent and efficient level of expenditure, considering the uncertainty mechanisms in the Access Code that are designed to account for material emerging needs that cannot be managed within the allowance.

These include:

- the **ex-post review** of expenditure as part of the NFIT process
- the ability to, and expectation that, the business will regularly **reprioritise investment within the total CAPEX allowance** – and more broadly within the total revenue allowance – towards the most imminent risks (Such as the reallocation of over $100m in AA4 from replacement CAPEX to the large and un-forecast SCADA/Comms investment).
- the **comparatively accessible 'reopener' provisions** of the Access Code which do not require the entire decision to be remade (as is the case for the AER regulated businesses) but allows for reopening a determination to make adjustment for a single issue.
- the **'Investment Adjustment Mechanism'** which allows the business to recover the volume of investment that is actually made in certain categories – rather than having all forecast CAPEX available to the business as part of a total CAPEX allowance.

These provide sufficient means to manage the emergent risks in AA5 within the CAPEX allowance and NFIT ex-post review process in the first instance; reopener adjustments available beyond that and prudent use of the IAM for categories where the required scope is uncertain.

4.5 Specific Risk Issues Identified by Western Power

Western Power has identified various risk issues arising from the reductions in the asset replacement program. However, Western Power does not acknowledge the flexibility in the Access Code that provides ready mitigation for these issues. These mechanisms would typically be considered in business case development and regulatory planning to ensure that their proposal does not overstate the risk – and therefore the CAPEX and OPEX requirements.

The regulatory framework ensures that the financial risk to Western Power is minimised as far as is efficient to enable the business to obtain finance on favourable terms. This is because customers benefit from lower financing costs for assets that they will be obliged to pay for anyway as a natural monopoly service. It also incentivises Western Power to find efficiencies and make improvements over time so that the business and customers can share the benefits through higher revenue and lower prices, respectively. These incentives are skewed if the CAPEX allowance is overstated – resulting in less pressure on the business to find efficiencies and less willingness of the business to pursue the ones that are identified. With these measures in place, we consider that there are no material risks relating to 'Regulatory Error' that mean Western Power would be unable to fulfil its obligations for AA5. Notwithstanding this, underperformance may still occur should Western Power be unable or unwilling to reoptimize investment against risk throughout the period in a manner that enables prudent and efficient use of the regulatory risk management levers that are available to it.

At a transmission level, Western Power identifies how it will manage risks – ostensibly by seeking reduced service levels and increasing its qualitative risk assessments for 'customer risk' from 'medium' to 'high'.

At a distribution level, Western Power acknowledges that it is able to accept the decision, through operational responses

As a result, we remain of the view that the identified risks are an over-reliance on the Mean Replacement Life in anchoring its forecasts. We consider that Western Power has not addressed these concerns in its Revised Proposal.

5.0 SCADA and Communications

5.1 Summary

We recommend the additional $71.6 million proposed by Western Power over the AA5 period for increased SCADA and Communications and Corporate ICT expenditure not be included in Western Power's CAPEX forecast.

This was based on the comparison of the total SCADA, ICT and Communications expenditure with other Australian DNSP's and TNSP's. As noted in our previous report, we made this comparison at a total level to ensure that our assessment was not influenced by differences in classification of corporate IT, network IT, communications and operational technology costs within and across the Australian network businesses. In making this comparison, we considered the range of DNSP vs TNSP costs, and found that Western Power's proposal was well above the combined cost for a standalone DNSP and TNSP of comparable or larger scale.

Western Power's Revised Proposal outlines several cyber security and asset obsolescence concerns as drivers for the investment needs.

We agree with the risk management objectives outlined by Western Power and acknowledge the ongoing need for addressing cyber security risk in a changing and increasingly digital energy landscape. However, we hold significant deliverability and customer impact concerns for these programs, as well as maintain our prior concern regarding the limited compelling justification and analysis in the documentation provided for a program of this scale.

The Revised Proposal does not engage with the concerns raised in our initial review, the ERA's Draft Decision, or stakeholder submissions, or definitively demonstrate how Western Power would address those concerns. The Revised Proposal has not included sufficient evidence regarding quantification of risks or net benefits to network users, sufficiently detailed business cases or options analysis, or provided sufficient evidence of efficiency and prudency of investments. This is particularly pertinent given the scale of the investment for the program and the comparative scale-up to both network peers and prior regulatory periods.

While the Revised Proposal notes an inability to maintain business services with a 30 per cent reduction as the draft decision recommends, Western Power has previously demonstrated its reprioritisation approach in AA4 with the reallocation of over $100 million in CAPEX towards the SCADA and Comms category from the replacement program. Therefore, whilst noting Western Power's concerns, we consider the ERA's draft decision provides a CAPEX allowance that is already at the extreme upper end of expectations for Australian distributors and transmission service providers.

Additionally, information provided in the Revised Proposal has only referenced the incremental expenditure above the draft decision allowance with limited detail provided on the impact to the remaining composition, distribution and financial outcomes or timing flexibility for the remaining SCADA and Communications program components. This appears to have been achieved by:

- applying the ERA's 30 per cent adjustment proportionally across each individual SCADA and Communications projects
- identifying components that could not be rescoped and delivered with a 30 per cent reduction in budget during AA5
- proposing additional expenditure for these components.

This approach implicitly assumes that all components of the program pose identical risk, benefit, interdependency profiles and timing requirements, creating a lack of transparency and clarity over program direction for AA5 required by the NFIT.

Given the absence of additional information on how the risks could not be managed, compelling supporting justification or detailed quantification, we maintain the advice provided to the ERA following Western Power's initial proposal.

We recommend the ERA maintains its draft decision for SCADA and telecommunications and Corporate ICT investment of $522.2 million.

5.2 Western Power's initial proposal

Western Power's initial AA5 proposal included a total of $413.4 million of CAPEX for SCADA and telecommunication (Dx and Tx) and an additional $332.8 million for Corporate IT.

Table 10 - Western Power's proposed SCADA and Corporate ICT expenditure for AA5 – excluding forecast labour escalation and indirect costs ($ million real 2022)[27]

	2022/23	2023/24	2024/25	2025/26	2026/27	Total AA5	AA4 actuals
SCADA and telecommunications							
Asset replacement	34.5	34.2	26.7	31.5	34.2	161.2	77.2
Master station and operating system	19.4	16.6	26.0	24.5	26.5	112.9	64.0
Compliance	8.2	12.2	19.7	20.5	19.9	80.4	13.9
Other	9.9	9.4	11.9	13.6	13.6	58.6	41.0
Total SCADA and telecommunications	**72.0**	**72.4**	**84.3**	**90.1**	**94.4**	**413.1**	**196.4**
Corporate ICT	60.9	66.4	65.8	72.7	66.9	332.8	255.9
Total SCADA and corporate IT	**132.9**	**138.8**	**150.1**	**162.8**	**161.3**	**745.9**	**452.3**

The AA5 proposal for SCADA and communications is an additional $216.7 million (110 per cent) over the AA4 historical spend. Western Power states the age of equipment, increasing volume of renewables and greater DER integration are an increasing driver for upgrades. Additionally, it appears a change in Western Power's ICT risk appetite, significant investment into a Tx and Dx Master Station, and large increases in SPS and AMI CAPEX programs have contributed to the proposed increase in spending.

Western Power proposed extension of life rather than replacement of SCADA and Communication assets will lead to lower reliability and asset availability, higher OPEX and workforce impacts and an inability to meeting emerging requirements relating to cyber security, DSO, DER and Technical Rules. For those reasons, Western Power proposed significant investment for asset replacement and upgrades in its AA5 proposal.

[27] ERA Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27 Attachment 3B: AA5 Capital Expenditure, p28

5.3 Engevity advice on ERA's draft decision

Following review of Western Power's initial proposal, Engevity assessed that:

- Western Power has not made a clear case that reliability is falling below acceptable levels due to obsolescence and non-compliance of IT, SCADA and Communication assets. Engevity points to the Network Management Plan which shows a relatively flat historic availability of SCADA and Telecommunication networks and forecasts an increase in reliability for CBD automation in the future.
- There is limited evidence of business case or investment evaluation plans for the total AA5 SCADA and ICT investment program.
- Our benchmarking assessment showed that Western Power's forecast is significantly higher than other regulated networks.
- We had found systemic issues with Western Power's approach to asset and risk management.

Taking account of these issues and Engevity's advice, the Draft Decision incorporated the reduction recommended by Engevity and the ERA considered the proposed expenditure should be reduced by $223.7 million in total as set out in Table 4-2 below.

The ERA considered the draft decision includes sufficient expenditure to allow Western Power to comply with its cyber security requirements.

Table 11 - ERA Draft Decision revision for Western Power SCADA and ICT CAPEX for AA5 ($ million real 2022)[28]

SCADA and Telecomms CAPEX	Proposed expenditure:	Adjustments:	Draft decision
SCADA & telecommunications	413.1	(123.9)	289.2
Corporate ICT	332.8	(99.8)	233.0
Total	745.9	(223.7)	522.2

5.4 Western Power's Revised Proposal

Western Power's Revised Proposal has accepted deferral of some, but not all, of the ERA Draft Decision. Western Power has sought $350 million for SCADA and telecommunications and $243.8 million for Corporate ICT, an increase of $60.8 million and $10.8 million respectively, compared to the Draft Decision (Table 4-3).

[28] ERA Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27 Attachment 3B: AA5 Capital Expenditure, p33

Table 12 - Western Power Revised Proposal for SCADA and ICT CAPEX ($ million real 2022)[29]

CAPEX category	*Initial Proposal*	*ERA Draft Decision*	*Revised proposal total*	*$M difference*	*% increase on Draft Decision*
SCADA and Telecommunications	413.1	289.2	350	+60.8	21
Corporate – ICT	332.8	233	243.8	+10.8	4.6

It is also worth noting the Revised Proposal for Corporate ICT expenditure includes a reclassification of $28.2 million for SaaS from CAPEX into OPEX, adopting the recommendation made in the Draft Decision. This results in a $38.8 million uplift for Corporate ICT expenditure compared to the Draft Decision.

Outlined in the table below, Western Power has argued that additional expenditure above the amount provided for in the Draft Decision is required so compliance requirements can be met relating to managing cyber risks, communicating with SPS assets and implementing recommendations of the Independent Review of Christmas 2021 Power Outages Final Report (referred to as the Shepherd Report). Concerns have been raised regarding material and technology obsolescence, cyber security risks, and improved and updated communication needs as drivers for the investment.

Table 13 - Western Power Revised Proposal CAPEX change by activity ($ million real 2022) rounded to whole numbers reflecting WP proposal [30]

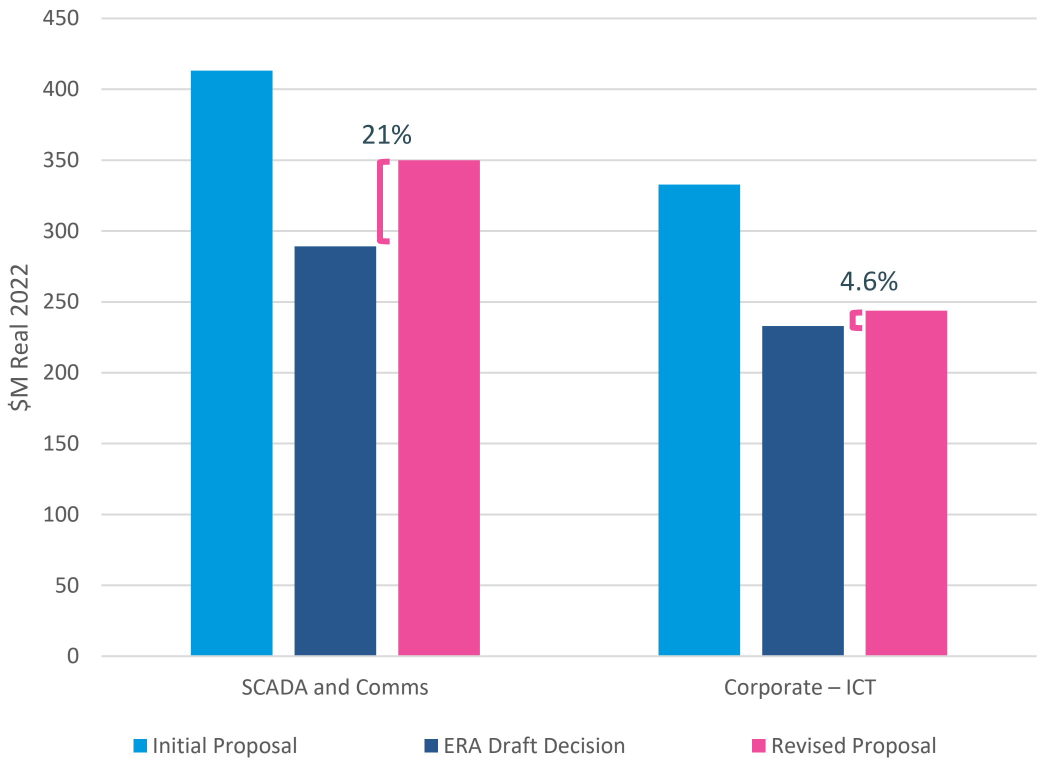
CAPEX classification	Regulatory Activity	Expenditure Adjustments
SCADA and Telecomms	Address cyber security risks	30
	Manage cyber security risks at the Master Station	16
	Enable communication with SPS assets	15
Corporate ICT	Manage key cyber security risks	31
	Meet customer communication expectations in line with recommendations of Shepherd Report	8
	Reclassification of SaaS ICT as Opex	-28
Total spend		100
Net change from Initial Proposal		+72

29 Western Power Revised Proposal, pp69-70

30 Western Power Revised Proposal, pp68-70

The revised expenditures are an increase of 21 per cent on the Draft Decision for SCADA and telecommunications and an increase of 4.6 per cent on Corporate ICT (see Table 12). Without the reclassification of SaaS expenditure, the revised expenditure for Corporate ICT would be an increase on the Draft Decision of 16.7 per cent.

Figure 15 - Western Power initial and revised SCADA and ICT CAPEX investment against ERA Draft Decision (Direct $ million real 2022)



5.4.1 SCADA and telecommunications

Western Power's Revised Proposal includes $350.0 million for SCADA and telecommunications, a 21 per cent increase on the ERA Draft Decision of $289 million.

The Revised Proposal reflects an additional $60.8 million across the following programs[31]:

- $30 million to address the cyber risks related to obsolete assets
- $15 million to enable communications with SPS assets
- $16 million for the master station to manage cyber risks.

Western Power argued the additional CAPEX is required to prevent the following outcomes:

- Difficulty managing higher number of cyber security risks due to incompatible assets with the cyber security requirements extending the MRL of the subset of assets which cannot meet new capacity requirements
- High pressure on maintenance and support workforce with a reactive approach
- Increases in operating and maintenance expenditure and reduced reliability incurred by replacement on failure

31 Western Power Revised Proposal, p68

- Increased level of technical non-compliance and possible penalties
- Inability to meet customer expectations
- Delayed integration of new assets, including DER, microgrids, network batteries, SPS, Depot Modernisation, resulting in risk of reduced physical security.

Western Power cites the need to perform upgrades or replacement for SCADA and telecommunications assets when the manufacturer ceases to provide support as a driver of CAPEX requirements. This is typically in the range of 7 to 12 years for SCADA and telecommunications assets, with 10 to 15 years possible at a cost premium.

Western Power asserts the cost premium for extension of support or provision of patches is less cost effective than carrying out the upgrade. Where cost effective, Western Power utilises a partial upgrade process to 'harvest spares' and thereby further increase the asset life.

For these reasons, Western Power considers a reduction in investment to meet the Draft Decision would require a significant increase in OPEX to fund extended support over the AA5 period and will result in an increase in cyber security risk beyond corporate risk tolerance levels within 12 months.

5.4.2 Corporate ICT

Western Power's Revised Proposal includes investment in Corporate ICT assets of $243.8 million, a net increase of $10.8 million (4.6 per cent) over the Draft Decision. This is comprised of[32]:

- an additional $31 million to manage key cyber security risks
- an additional $8 million to meet customer communication expectations and align with the recommendations made in the Shepherd Report
- a reduction of $28.2 million relating to SaaS expenditure reclassification to OPEX.

5.4.3 Cyber security

Western Power undertook cyber audits and assurance activities following the submission of its initial proposal, which identified unacceptable levels of operational risk for the business with corrective action recommended. Western Power has argued the Cyber Security Strategy cannot be implemented for 30 per cent less than estimated cost without sustaining unacceptable levels of cyber security risk.

The audit has also highlighted the need for an updated Cyber Security Strategy, which Western Power submits will require additional funds to enhance its cyber security framework and operate within acceptable risk levels.

Western Power proposes:

- work is planned over five years in line with the strategy, which will require readjusting forecasts to accommodate a faster than anticipated spend on cyber projects
- tactical work on the updated strategy commences as soon as possible to operate within acceptable risk levels.

5.4.4 Customer communication

Western Power proposes to include a new investment of $8 million to improve customer communications in line with customer expectations and reliability data. Western Power notes the Shepherd Report was released following submission of the Initial Proposal and thus was not accounted for in the initial proposal or draft decision.

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[32] Western Power Revised Proposal, pp69-70

The Shepherd Report highlighted Western Power should improve on the following:

- more regular and detailed communication during an outage
- greater use of direct customer communication before and during an event
- the use of warnings where an outage can be reasonably forecast and is likely
- communication to customers about how a change in their energy use may reduce the risk of an imminent outage
- distinct communication strategies for vulnerable customers (including those on life support)
- recognition of the health impacts during a heatwave and appropriate health messaging/referrals
- greater engagement with impacted Local Government Areas (LGAs).

Western Power is acting on a number of improved communication channels prior to December 2022. Further improvements seek to[33]:

- enhance automated customer communications to support multiple options, for example, communication media, frequency and severity
- improve customer records, allowing individual customers, not only network connections, to be distinguishable, in order to capture customer communications preferences and consolidate communications for the multiple interactions with a single customer
- establish a customer "portal", allowing customers to securely log-on to Western Power's website, for customers to manage their preferences through self-service and receive personalised information. This includes the implementation of customer identity services
- improve outage duration and customer impact analytics, covering the range of outages, from frequently occurring outages to more complex, evolving environmental driven events, allowing more informative customer outage communications
- develop network analysis algorithms to dynamically forecast where customer energy usage may reduce risk of imminent outage and then the automation of the associated, targeted customer communications
- enhancements to make Western Power's website more consumable to customers for both outage information and information on how energy use can reduce outage risk
- introduce analytics and testing on Western Power's website to allow website communications to be continually assessed and improved
- develop a suite of reports to manage and monitor the effectiveness of customer communications to allow continued improvement of communications.

The revised SCADA and telecommunications CAPEX is summarised in Table 4-5.

Figure 16 - Western Power proposed SCADA and ICT CAPEX for AA5 (Direct $ million real 2022)[34]

Expenditure category	Initial Proposal	ERA Draft Decision	2022-23	2023-24	2024-25	2025-26	2026-27	AA5 revised

[33] Western Power Revised Proposal, pp72-73

[34] Western Power Revised Proposal, pp68, 70

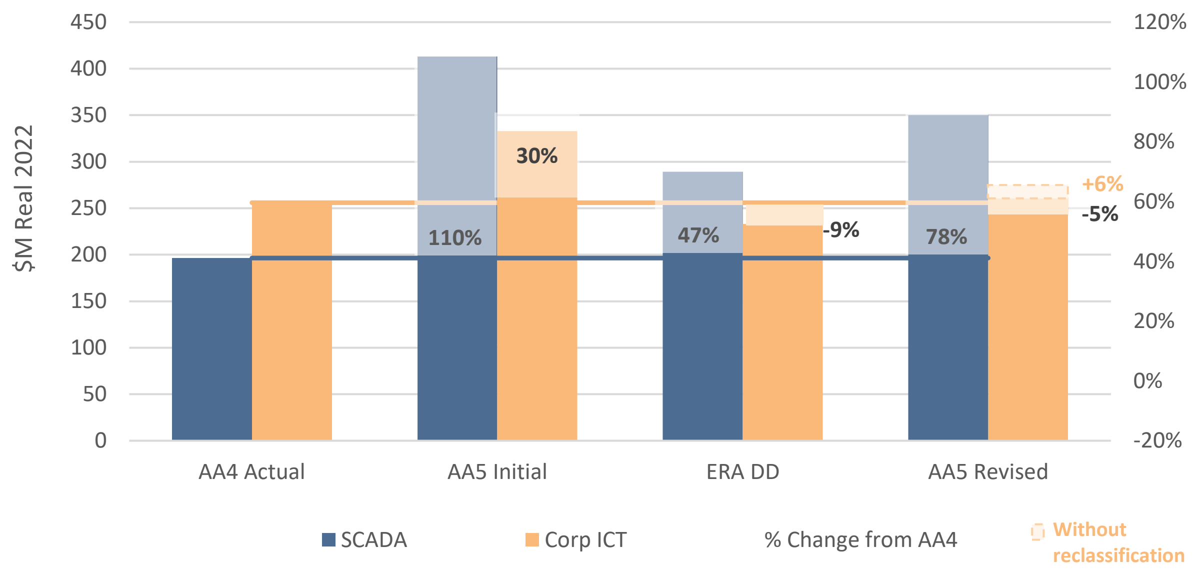
SCADA and telecommunications	413.1	289.2	53.5	67.4	73.5	74.8	80.9	350.0
Corporate ICT	332.8	233.0	48.1	48.3	46.5	52.3	48.6	243.8

Western Power submits the revised expenditure total believed to be reasonably expected to meet the NFIT requirements and which should be included within the RAB.

5.5 Engevity's analysis

5.5.1 Historical context

Figure 17 - Western Power initial and revised SCADA and ICT CAPEX investment against ERA Draft Decision (Direct $ million real 2022)



Engevity noted in its initial review the proposed AA5 CAPEX was a step change increase from the actual investment undertaken during AA4. The ERA's draft decision amount recognised the need for increased spend on AA4 investment at a level that was deemed as being better aligned to meeting customer needs.

The figure above outlines the comparison between each CAPEX proposal against the AA4 period. The revised AA5 proposal for SCADA and telecommunication is a 78 per cent increase on the historical AA4 investment. The revised AA5 Corporate ICT expenditure is a 6 per cent increase on AA4 investment without the transfer of SaaS to OPEX, but becomes a 5 per cent reduction on actual AA4 investment when the reclassification of SaaS into OPEX is taken into account.

5.5.2 Benchmarking

In terms of how Western Power aligns to its peers, Engevity noted in its initial review it expected a range of $200–$350 million for SCADA and Communications expenditure based on AER expenditure approvals of similar programs for other NSPs. Western Power now sits within that range, albeit at the extreme highest end of the spectrum, with peer network expenditure demonstrated in the table below.

Table 14 - Other network ICT expenditure

	$real	*Period*	*Final Approved AER Expenditure*
SAPN	2020	2020-25	$279.4m[35]
Energex	2020	2020-25	$147.7m[36]
Ergon	2020	2020-25	$164.4m[37]
Endeavour	2019	2019-24	$120.16m[38]
Essential	2019	2019-24	$98.5m[39]
Ausgrid	2019	2019-24	$144.2m[40]
TransGrid	2018	2018-23	$84.3m[41]
Powerlink	2017	2017-22	$105.8m[42]

At the revised figure of $350 million, Western Power remains $70 million above the next highest approved NSP – SAPN – for its SCADA expenditure and more than double the average NSP expenditure.

5.5.3 Deliverability

We noted in our previous report that we had not observed a detailed resourcing and delivery plan that considers how an accelerated increase in expenditure is achievable. Globally ICT resources and equipment are in high demand, and we remain aware of skill shortages which may impact the delivery of this proposed expenditure.

Within Australia, the major geographical skills centres for ICT are in the eastern states. Whilst Western Power has previously been able to attract skills from the east in the tight labour market conditions during the mining boom, the scale of electricity infrastructure investment that is committed in the eastern states, along with the SCADA and comms requirements of generators,

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35 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/final-decision

36 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/energex-determination-2020-25/final-decision

37 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020-25/final-decision

38 Includes Communication & ICT regulatory category. Source https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/endeavour-energy-determination-2019-24/final-decision

39 Includes Communication & ICT regulatory category. Source https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/essential-energy-determination-2019-24/final-decision

40 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausgrid-determination-2019-24/final-decision

41 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/transgrid-determination-2018-23/final-decision

42 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powerlink-determination-2017%E2%80%9322/final-decision

market bodies and operators means that there will be significant constraints for ICT resources with energy network expertise that will need to be managed for all Australian electricity networks.

The draft decision allowance provided for an increase to account for expected higher costs in labour and materials, as well as recognising the transitioning nature of the networks. Western Power has not provided further evidence to justify why a further increase is necessary above the ERA draft decision amount – or compelling evidence to demonstrate that expenditure that is more than twice the industry average in this category is necessary.

Western Power has not attempted to address the deliverability concerns raised in its Revised Proposal.

5.5.4 Cyber security

Across the $100 million of additional CAPEX proposed across the SCADA and communication spectrum of activity, Western Power has allocated some three quarters or $77 million towards cyber security risk. This indicates that Western Power is highly concerned about its cyber security and sees this as a significant threat to the operation of its network.

Concern for cyber security is also growing amongst other network service providers. We highlighted a trend towards increased spending by Western Power's peers in its initial review, referencing the increasing ICT expenditure of other networks to meet cyber security obligations.

Regulatory proposals concerning ICT expenditure and cyber security risk from other NSPs are typically well detailed with business cases outlining expected risks and impacts quantified, despite cyber security programs representing much lower amounts. For example, the SAPN revised IT business plan is covered over 42 pages, with only $5.5 million allocated for cyber security risk investment.

While Western Power has provided greater contextual detail around the increased concern regarding cyber risk in its Revised Proposal,[43] minimal information has been provided to demonstrate this level of investment is necessary, efficient, prudent, or achievable within the AA5 period.

We remain in agreement that an increasing threat of cyber security requires addressing and note that Western Power states its current Cyber Security Strategy cannot be delivered for 30 per cent less. However, Western Power has not provided justification for why its expected costs are much higher than its benchmarked peers or how it can deliver a program much higher than delivered in its AA4 period – in a tightening labour market. In the absence of these data, the investment proposal lacks justification against the NFIT.

While Western Power has demonstrated an increased risk appetite for its capacity to respond to cyber security threats, this is not supported by measurable impacts on the SCADA and ICT systems of the network. A change in risk appetite by the business is not a sufficient justification for increased expenditure unless accompanied by evidence of changing risks and impacts to the SCADA systems and network.

Western Power referenced a cyber security audit conducted following submission of its initial proposal, which identified risks Western Power considered at unacceptable levels for safe operation of the network.[44] However, Western Power did not provide the outcomes of the audit in its proposal, including whether any consequences of events, risks to customers or network, or expected costs were identified either within the audit or as a result of further analysis on the audit findings. Western

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43 ERA Capex Increase – Cyber Security – Corporate ICT and SCADA Comms Maintenance – 6 Dec 2022, ERA39 - Capex Increase - SCADA & Comms - Issue Briefing Paper (IBP) - Dx Automation and Control - Cybersecurity (60526309), ERA39 - Capex Increase - SCADA & Comms - Issue Briefing Paper (IBP) - Tx Automation and Control - Cybersecurity (61834493), ERA39 - Capex Increase - SCADA & Comms - Response Overview - 2 Dec 2022

44 Western Power's Revised Proposal, p. 76, para 229.

Power also did not provide any evidence that cyber security impacts on the business have changed since the previous regulatory period.

To align with the NFIT, significantly more detailed evidence base should accompany expenditure of this scale. To adequately demonstrate cost efficiency of the proposal, the submission should be supported by evidence that demonstrates expected quantified risks, reliability improvements, or net benefits for network users. A thorough and quantified options analysis should also accompany this expenditure, providing evidence and justification that the proposed solution is the most efficient solution and best outcome for customers. Western Power has not provided this evidence and therefore has not demonstrated how the proposed investment is aligned with NFIT criteria.

Furthermore, cyber security risks are included in the benchmark costs that were used to assess the reasonableness, or otherwise, of the original Western Power proposal. Therefore, we are of the view that the ERA draft decision allows for a prudent and efficient level of cyber security expenditure within the total allowance. As a prudent and efficient operator, Western Power will need to reprioritise its total CAPEX program over the course of AA5 to manage their risks as threats emerge and new information comes to light.

5.5.5 SPS communication

Western Power has also included $15m for communication with SPS assets. Other than to outline the amount required, Western Power has not provided any additional information regarding this program, either at a detailed or high level. We previously raised concerns about the high unit costs of Western Power's SPS program and understood that the program, as it stood – or otherwise the metering component of the AMI program included the necessary control and communication equipment to implement Western Power's SPS solution at scale.

The omission of details for the SPS program in the Revised Proposal raises questions regarding the robustness of Western Power's business cases for two of the largest network transformation programs in AA5. Further explanation of why this essential component of expenditure was excluded, detailed justification or a demonstration of why the expenditure could not be addressed by the budgets for these programs has not been provided.

5.5.6 Customer communication

Western Power has highlighted the recommended outcomes from the Shepherd Report that require action to ensure effective communication with customers[45]. We agree with the importance of improving customer communication and engagement and note its increasing importance to the health and safety of customers as extreme weather events and associated outages are likely to increase.

We also accept that this investment was not able to be included in the initial proposal due to the timing of the Shepherd Report's release. However, we note there is minimal detail in this investment proposal and significant uncertainty surrounding the program prudency or deliverability. While we acknowledge Western Power has provided program cost estimates, there is no evidence of options analysis to determine cost efficiencies.

A significant part of the customer communication CAPEX has been allocated for the upgrading of Western Power's website and similar customer-facing portals. While these activities can improve the customer experience, there is not a clear or supported connection between the expenditure and its necessity to adequately deliver business services. Inclusion of the Shepherd Report recommendations must be in alignment with criteria of the NFIT, the case for which has not been adequately made.

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[45] Western Power Revised Proposal, p71

Further, Western Power has made a significant investment in excess of $20 million in its Customer Management System over AA4 to enable capabilities such as customer self-service, improved customer communications and greater availability of information on outages to customers via online channels. The Revised Proposal does not outline how it intends to build on its existing capability or why recent improvements and planned further development are inadequate for business service delivery.

We consider that Western Power is already well placed to address much of the Shepherd Report requirements using the capabilities of existing and further planned development of its Customer Management Systems.

6.0 OPEX STEP CHANGES

6.1 Summary

Engevity recommends that the additional $108 million proposed by Western Power over the AA5 period for increased insurance costs, its silicone treatment program and private pole inspections (as outlined in section 6.2) should not be included in Western Power's total OPEX forecast. We consider that including these three step changes would lead to an estimate of total OPEX in AA5 that is above prudent and efficient levels.

Section 6.3 describes the assessment framework we applied to form this recommendation. We explain the economic foundations and underlying methodology of the base–step–trend forecasting approach, which was proposed by Western Power. This approach, combined with the ERA's gain sharing mechanism, is designed to 'reveal' Western Power's efficient costs and apply continuous incentives for it to improve network efficiencies over time.

The base–step–trend model is widely recognised as a robust forecasting methodology. It promotes economic efficiency in the long term interests of consumers, and allows the ERA to make judgements about efficient costs based on high-level outcomes to manage information asymmetries – consistent with the intent of best practice incentive regulation.

We consider the three proposed step changes identified by Western Power would create an upward bias in the base–step–trend OPEX forecast for AA5 for the following reasons (which are outlined in further detail in section 6.4):

- Western Power has demonstrated its ability to satisfy its obligations and service demand using its AA4 revealed costs – which forms the 'base year' for the AA5 OPEX forecast.
- The ERA is required under the Access Code to approve total costs and target revenue that would be incurred by a service provider efficiently minimising costs, rather than individual forecasts of OPEX components – including increases or decreases of individual OPEX activities. The ERA does not set Western Power's operating budget or determine what activities it should undertake to meet its regulatory obligations. Incentive regulation is designed to leave input and output decisions to Western Power, which is best placed to manage its risks and allocate its resources (as highlighted in section 4).
- Network OPEX comprises largely recurrent costs. Western Power's individual OPEX activities may vary from year-to-year and across regulatory periods, as it continuously reviews and re-prioritises its operations and work program to manage risks and meet relevant regulatory obligations, and as Western Power realises ongoing efficiencies. The resulting 'ups and downs' in the costs incurred for each OPEX item are captured within base OPEX – which is set based on a top-down assessment and then a forward trend in those costs are estimated to calculate forecast OPEX.
- Western Power's Revised Proposal has singled-out OPEX activities that may require increased expenditure in AA5. Regulatory experience for other Australian networks has shown that, in most cases, cost increases for 'business-as-usual' activities – like insurance and bushfire prevention – will typically be offset by decreasing costs for other OPEX items. This is a fundamental assumption of the base–step–trend model. Western Power does not have an incentive to identify these offsets (and it has not otherwise proposed a bottom-up forecasting approach or category specific forecasts). Therefore, the inclusion of the proposed step changes would change the balance of the incentive arrangements and create an upward bias in the total OPEX forecast. Only exceptional circumstances would warrant the inclusion of a step change in the OPEX forecast, which Western Power has not demonstrated.
- Costs related to the proposed insurance and private point of attachment poles (PPAP) step changes are already taken into account in the productivity growth factor of the OPEX

forecast. These costs are also incurred by other distribution networks in Australia. Their productivity trends are used to estimate achievable efficiency improvements by Western Power in AA5 (see section 7).

Overall, we consider the ERA's draft decision is sufficient without including Western Power's proposed step changes for insurance costs, the silicone treatment program and private pole inspections in the total OPEX forecast for AA5.

6.2 Western Power's Revised Proposal

Western Power's proposed steps changes for insurance costs, the silicone treatment program and private pole inspections are outlined below.

6.2.1 Insurance costs

Western Power is proposing an additional OPEX step change of $43.0 million for increased insurance costs over the AA5 period. It is noted that this cost increase was not identified in Western Power's initial proposal.

Western Power states insurance premium rates are subject to external factors that its other operating costs are not:[46]

> This means that insurance premiums are not expected to follow typical inflationary drivers (e.g. consumer price index or average weekly earnings) that apply to many of our other operating costs over the AA5 period.
>
> Whilst our insurance premiums largely reflect the risks of insuring our exposure to risk factors, other external factors have considerable bearing on insurance pricing.

Western Power submits its actual insurance premiums increased by 43 per cent from 2020-21 to 2022-23, and anticipates insurance premiums will continue to increase well above the rate of change component of its OPEX forecasts over the AA5 period.[47]

6.2.2 Silicone treatment program

To reduce the likelihood of pole top fires, Western Power washes and applies silicone grease on insulators periodically for its distribution overhead network.

Western Power changed its work practices in 2021 whereby the silicone application process is applied while the line is de-energised, rather than energised. Western Power argued in its initial proposal that it faced higher unit rates for this OPEX category due to the additional time and resources required to plan and execute outages on lines to be treated. Further, Western Power considered live-line washing and siliconing will result in compliance breaches to the *Work Health and Safety Act 2020* and Western Power's Safety, Environment and Health Policy and Asset Management Policy. On this basis, Western Power proposed a step change of $26.4 million.[48]

In its draft decision, the ERA rejected this proposed step change based on Engevity's finding that the move away from live-line work is not required under the relevant Energy Safety Order, which recommends improved equipment testing, compliance and work practices for live-line insulator washing. This is also consistent with the Victorian Electricity Supply Industry guidelines and recent awareness publications involving washing equipment condition.[49]

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46 Western Power Revised Proposal, p. 82.

47 Western Power Revised Proposal, p. 83.

48 Western Power initial proposal, pp. 152–153.

49 ERA draft decision, Attachment 6: Operating expenditure, 9 September 2022, pp. 12–13.

In its Revised Proposal, Western Power has increased forecast OPEX for this step change to $40.3 million. Western Power states it is likely to re-start the live-line silicone program from 2023-24. Western Power now argues the primary driver for this step change is to mitigate the risk associated with pole top fires due to the accumulated backlog caused by a safety-related pause on the live-line silicone treatment program. Western Power will potentially introduce new work practices based on trials and further investigations, which have provided a potential live-line washing and siliconing option through the use of helicopters.[50]

6.2.3 Private pole inspection

Western Power is proposing an additional OPEX step change of $24.3 million for the management of PPAPs over the AA5 period. Western Power states the requirement for this expenditure is driven by obligations from a court judgment issued by the Supreme Court of Western Australia, Court of Appeals in July 2021 with regards to the Parkerville private pole failure case.[51] The Court found that Western Power breached its existing duty to have a system for undertaking the periodic inspection of wooden point of attachment poles owned by customers and used to support live electrical apparatus.[52]

Under the obligation imposed by the Court decision, Western Power's submits its responsibilities include:[53]

- performing the necessary inspections on PPAPs in order to understand their condition
- utilising this information to assess the likelihood of failure, potential consequences of failure and level of risk represented by these assets in accordance with the engineering practices that Western Power applies to its own assets
- issuing a notice to the owner of the pole on the required maintenance to perform on the pole, up to and including replacement. In the most serious cases, or where the notice period has expired and the pole condition has not been rectified, this includes the immediate disconnection of the service, and reconnection after the remediation works have been carried out.

Western Power says this proposed expenditure was not in its initial proposal due to the timing of the Court judgement. Although Western Power had lodged an appeal to this decision, it considers until and unless the appeal is successful, it is obliged to follow the requirements of the Court decision. The appeal was heard in the High Court of Australia in September 2022.[54] The High Court dismissed Western Power's appeal on 7 December 2022.[55]

6.3 Assessment framework

A key feature of the regulatory framework under the Access Code is that it is based on incentivising network service providers to be as efficient as possible, while meeting their statutory obligations. Locking-in revenue at the start of the regulatory period and the gain sharing mechanism both create incentives for network service providers to become more efficient over time. The ongoing monitoring of compliance, core management systems and network performance provides a safeguard for prudent decision making.

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[50] Western Power Revised Proposal, pp. 77–82.

[51] Western Power Revised Proposal, pp. 84–85.

[52] HERRIDGE PARTIES V ELECTRICITY NETWORKS CORPORATION T/AS WESTERN POWER [2021] WASCA 111.

[53] Western Power Revised Proposal, p. 84.

[54] Western Power Revised Proposal, p. 84.

[55] See: hca-37-2022-12-07.docx (live.com)

We consider applying a revealed cost framework – using the base–step–trend model, as proposed by Western Power – is best regulatory practice for undertaking OPEX assessments. The explanation below of the design of this economic mechanism heavily draws from Engevity team members' experience supporting the Australian Energy Regulator (AER) to develop its OPEX assessment framework and in making decisions applying the base–step–trend model. These principles form the basis of most of the incentive regulation frameworks within Australia and internationally, and translate directly to the ERA's assessment of Western Power's proposed OPEX under the Access Code.

6.3.1 Incentive regulation helps overcome information asymmetries

Network service providers have a significant information advantage both to understand their true efficient costs, and identify existing inefficiencies and inflated cost forecasts. The revealed cost approach and economic benchmarking are the two main tools regulators can use to overcome this information asymmetry.

First, incentive regulation encourages network service providers to reduce costs below forecast levels and 'reveal' their efficient costs in doing so. The information revealed by the network service providers allows the regulator to ensure expenditure forecasts capture these revealed efficiencies.

To elaborate, revealed OPEX reflects the efficiency gains made network service providers over time, as well as the cost of new obligations that have previously come into effect. As network service providers become more efficient they benefit from gain sharing mechanism payments. This translates to lower forecasts of OPEX in future regulatory periods – which means consumers also receive the benefits of the efficiency gains made by the network service providers. Incentive regulation therefore aligns network service providers' profit-maximising objective with the long term interests of consumers.

Second, economic tools allow the regulator to develop an alternative estimate of total OPEX using a top-down forecasting method to avoid the minutiae of a 'bottom-up' OPEX forecast and base its decision on high-level outcomes.[56]

Indeed, incentive regulation is designed to leave the day-to-day decisions to network service providers. This is consistent with the requirement that the regulator approves total costs and target revenue that would be incurred by a service provider efficiently minimising costs, rather than individual forecasts of OPEX components. The regulator must assess whether OPEX in aggregate is sufficient to satisfy the Access Code requirements – not increases or decreases of individual OPEX activities.

The regulator's allowed revenue determination does not set network service providers' actual operating budget over the regulatory period. The regulator does not determine what activities network service providers should undertake or how much they should spend on particular categories of OPEX. This level of focus on detail would be counter to the conceptual underpinnings of incentive regulation.

Network service providers have the flexibility to manage their operations as they see fit. It is for the network service providers to prioritise and decide what suite of projects and programs they should undertake to deliver services to their customers – while meeting their regulatory obligations. Network service providers are expected to make the most efficient use of their resources. Management's role is to manage risks, compliance obligations and performance within funding

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[56] A 'top-down' approach forecasts total OPEX at an aggregate level, rather than forecasting individual projects or categories to build a total OPEX forecast from the 'bottom up'. Any volatility of total OPEX from year-to-year does not necessarily impact the choice of the appropriate base year. Although applying a base year with unusually high OPEX would typically result in an increased OPEX forecast, this would be offset by a lower gain sharing mechanism reward or greater penalty.

constraints to deliver a cost effective, safe and efficient service to consumers, whilst maximising returns to shareholders (as also discussed in section 4).

6.3.2 Efficient allocation of risk

The incentive based regulatory framework does not provide network service providers with a guaranteed rate of return or a right to recover their actual costs. Certain risks are allocated to and borne by network service providers, while others are shared with consumers.

To promote efficient outcomes in the long term interests of consumers, risks should be borne by, or allocated to, parties who are in the best position to manage them. In principle, the party holding the risk should have:

- incentives to manage the risk, because it stands to gain or lose from doing so, and there is a clear link between its actions and the outcomes of the risk
- more information than other parties to manage risk since it can use this information to better mitigate the impact of the associated loss
- the ability to better manage risk than other parties, so it can take actions to avoid or reduce the impact of the associated loss
- the ability to improve risk management over time through experience.

Consumers of network energy services are not in a position to influence the businesses' strategy to manage their OPEX programs, such as staffing decisions and any re-prioritisation of resources to manage the safety of the network. And consumers do not have the choice of changing their network service provider.

Shifting the risk of business inefficiencies or poor decisions away from the managers of network service providers would not incentivise good decision making or a focus on achieving greater productivity. The regulatory framework, in attempting to mimic competitive market disciplines, should not reward inefficiencies resulting from the network service providers' own actions or inaction. To do so would weaken the effectiveness of the incentives the regulator places on network service providers under the regulatory framework – to the detriment of consumers.

6.3.3 Base OPEX reflects year-to-year variations in OPEX categories

We consider revealed OPEX in the base year is generally a good indicator of OPEX requirements over the next period because the level of total OPEX is typically stable from year-to-year – or, more relevant to the task of estimating total efficient OPEX, from regulatory period to regulatory period.

This reflects the broadly predictable and recurrent nature of OPEX. Network service providers may experience fluctuations in particular categories of OPEX, and the composition of total OPEX can change, from year to year. While many operation and maintenance activities are recurrent and non-volatile, some OPEX projects follow periodic cycles that may or may not occur in any given year, and some OPEX projects are non-recurrent.

Even if disaggregated OPEX categories have high volatility, the total OPEX varies to a lesser extent because it can be reasonably assumed that new or increasing components of OPEX are generally offset by decreasing costs or discontinued OPEX projects. Further, the network service providers are expected to manage the inevitable 'ups and downs' in the components of OPEX from year to year – to the extent they do not offset each other – by continually reviewing and re-prioritising their work programs, as would be expected in a competitive market.

If a network service provider has demonstrated its ability to satisfy its obligations and service demand in the past using its revealed costs, any further adjustments to base OPEX risk introducing bias into the forecast. It is therefore important to carefully scrutinise any such proposed adjustments.

Finally, continued use of the base–step–trend methodology 'self corrects' for any over or under forecasting of total OPEX in subsequent regulatory periods – given base year OPEX reflects actual expenditure.

6.3.4 Basis for approving step changes under the base–step–trend framework

In assessing step changes, consideration must be given to whether the costs are already accounted for by other components of the base–step–trend forecasting method to avoid the risk of 'double counting'. For example, costs associated with increased volume or scale would be compensated for through the output growth component of the rate of change. An additional specific allowance for such costs would overstate the total OPEX forecast.

Also, forecast productivity growth accounts for material increases in network service providers' input costs over time – so, higher cost inputs caused by exogenous factors that impact the broader industry, including potentially new regulatory obligations, are assumed to be compensated through a lower productivity estimate. Therefore, step changes should not be applied to cost categories that are captured in the historic average rate of change, as accounted for in the productivity growth forecast.

To maximise the level of approved revenue it may collect from users through network charges, a network service provider has an incentive to identify new costs not reflected in base OPEX or costs increasing at a greater rate than the rate of change. However, there is no corresponding incentive to identify those costs that are decreasing or will not continue.

Moreover, certain categories of investment such as ICT systems and hardware as well as remote monitoring and control assets are typically made on the basis of facilitating efficiency improvements through automation, better information or the avoided need to attend a site for maintenance activities. These accrue consistently over time as new ICT systems are integrated, new assets are commissioned, and maintenance practices optimised following technology renewal. Information asymmetries make it difficult for the regulator to identify those future diminishing costs as the realised benefits are typically not well tracked in businesses, and the network service provider does not have an incentive to include them in the OPEX forecast.

Therefore, a network service provider simply demonstrating that a new cost will be incurred – that is, a cost that was not incurred in the base year – is not necessarily sufficient justification to introduce a step change. There is a risk that including such costs would upwardly bias the total OPEX forecast.

We consider only exceptional circumstances would warrant the inclusion of a step change in the OPEX forecast – which is generally consistent with the approach that has been adopted by Australian regulators. For example:

- A step change may be required in circumstances where it is prudent and efficient for a network service provider to increase its OPEX in order to reduce its capital costs. The network service provider would need to demonstrate the OPEX–CAPEX tradeoff will lead to improved or at least neutral outcomes for consumers.
- A step change in a network service provider's OPEX forecast may be justified if a material step up in expenditure is required to prudently and efficiently comply with a new, binding regulatory obligation that is not otherwise reflected in the productivity growth forecast. If so, the network service provider may be expected to incur such costs into future regulatory periods – so an increase in its OPEX forecast may be warranted. A step change can also include the removal of a regulatory obligation on the network service provider that means it will no longer incur the associated costs in future regulatory periods.

Justification of a step change in these latter circumstances would not necessarily include instances where the network service provider has identified a different approach to comply with its existing regulatory obligations that may be more onerous, or where there is increasing compliance risks or costs the network service provider must incur to comply with its regulatory obligations.

6.4 Engevity analysis

Western Power proposed and the ERA has applied in its draft decision a revealed cost forecasting approach using the base–step–trend model to forecast total OPEX. Under this approach, simply identifying a new or increasing cost is not sufficient justification for a step change – given information asymmetries between the ERA and Western Power, and the risk of creating a forecasting bias in total OPEX.

As discussed above, aggregated OPEX includes rising and falling OPEX items. The composition of OPEX typically varies from year-to-year and it is reasonably assumed that many of these variations will offset each other. It is also expected that Western Power can manage the inevitable 'ups and downs' in the components of OPEX from year to year – to the extent they do not offset each other – by continually re-prioritising its work program over each regulatory period to manage changing risks. Collectively the three proposed step changes of $108 million are a small percentage of the ERA's draft decision for total AA5 OPEX of over $2 billion.

We consider Western Power has not identified exceptional circumstances to warrant an additional step change, as explored below. Allowing higher total OPEX for the three step change cost increases identified by Western Power would potentially create a significant forecasting bias.

6.4.1 The proposed step changes should be accounted for in the total OPEX forecast

Insurance and PPAP step changes

We consider allowing for the insurance and PPAP step changes proposed by Western Power would risk an over-allowance for these costs in the total OPEX forecast.

First, if similar PPAP management obligations have been implemented by other comparable network businesses in Australia over the last five to 10 years, the proposed steps change could be adequately accounted for through the productivity growth factor component of the OPEX forecast. As discussed in section 6.3.4, step changes should not be applied to cost categories that are captured in the historic average rate of change.

We found from a desktop review:

- The NSW distribution networks were recently required to routinely inspect privately-owned power poles and powerlines as part of its regular network asset risk management program, and in accordance with the *Electricity Supply Act 1995* and Electricity Supply (Safety and Network Management) Regulation 2014. If the network business identifies a defect, it must notify the customer in accordance with the Act. The customer is then required to remedy the defect using a licenced electrical contractor to ensure any safety and/or bushfire risks are well managed. In some cases, if there are no local service providers, or the customer has not complied with the request to repair their private poles, the distribution network will undertake the work at the customer's expense.
- The Victorian distributors, under the *Electricity Safety Act 1998*, were required to inspect all private overhead electric lines in accordance with the prescribed standards. If an inspection carried out by the distributor reveals that maintenance is required, it must give the owner of the land written notice of the maintenance required.
- In South Australia, SA Power Networks does not appear to have a formal statutory requirement to inspect private poles. However, in practice, we are aware SA Power Networks undertakes at least some inspections of private poles. For example, when SA Power Networks inspects one of its lines that terminate on a customer's private pole, it will also inspect the private pole. Also, SA Power Networks inspects private poles in circumstances where it

> identifies that there may be fire start or other risks. If SA Power Networks determines there is an issue, it notifies the pole owner and may, if there is a serious risk, disconnect the asset until the private pole is fixed.

Western Power has not established that the costs incurred by comparable network businesses to meet the above obligations are not reflected in the historic average rate of change used to estimate the productivity growth factor.

Second, if there has been changes in Western Power's *and* other comparable Australian network businesses' operating environment that are leading to increased insurance costs, these changes would be captured by the productivity growth factor component of the OPEX forecast under the base–step–trend framework.

We consider the insurance costs of other network businesses in Australia would also be impacted from the external factors identified by Western Power, including:[57]

- increasing inflation
- recent claims activity of other insured businesses (nationally and globally)
- increased frequency and severity of natural catastrophes
- demand from other utility companies and government entities for the same types of insurance
- market capacity available
- capital requirements.

Western Power has not demonstrated its insurance costs are increasing at a greater rate than the rate of change experienced by the broader industry.

Silicone treatment program step change

In our previous assessment of the silicone treatment program, we found that the AA4 and prior periods included energised line insulator washing/silicone treatment works.[58] Therefore, the value of these works are implicitly included in base OPEX.

We note the issue that triggered the move to de-energised insulator washing related to the washing sticks / wands provided by Western Power being non-compliant and overdue for testing. The WA Department of Mines, Industry Regulation and Safety describes the issue as follows:[59]

> An investigation by the State's electrical safety regulator, Building and Energy, found **the wand provided to the employee did not comply with the required standards** for washing sticks used near live electricity.
>
> Following the preliminary findings of the investigation, **WA's Director of Energy Safety issued an order reminding all service providers and network operators about the type of live-line washing equipment that is permissible for use**, as well as precautions they must take for such activity.
>
> The standards require live-work sticks to have insulating rods or foam-filled tubes made from fibreglass-reinforced plastic insulation. **The court was told that the live-work stick provided**

57 Western Power Revised Proposal, p. 82.

58 Engevity report to ERA, Attachments, August 2022 p. 106.

59 WA Govt. Department of Mines, Industry Regulation and Safety, *Western Power fined for safety failures after injuries to line worker,* https://www.commerce.wa.gov.au/announcements/western-power-fined-safety-failures-after-injuries-line-worker [emphasis added]

to the worker was hollow and had an aluminium rod, which failed to protect against the electrical discharge. **The stick was also overdue for mandatory testing**. [Emphasis added]

Overall, there is no prohibition on live-line insulator washing providing that appropriately certified foam filled, fibreglass wands are used. Western Power has discretion to investigate alternative methods of delivering its insulator washing program, including by helicopter, drone or when de-energised. In doing so, these alternatives would typically need to provide a more efficient delivery than the historical live-line washing practices, or otherwise contribute network reliability, operational or other tangible benefits that would justify the incremental expense.

By spending more on silicone treatment to reduce the likelihood of pole top fires, based on new work practices identified between its initial and Revised Proposal, Western Power may face lower costs in other OPEX categories. For example, it is possible Western Power may face lower insurance premiums as a result. These interactions between different OPEX categories are highly complex, and Western Power does not have an incentive to identify any offsets that benefit the business.

6.4.2 The proposed step changes are not justified based on new regulatory obligations

Western Power does not maintain new regulatory obligations are driving increased insurance or silicone treatment costs. These are typical network activities and the costs can be considered 'business-as-usual' expenses for Western Power. For example:

- The active management of insurances is a core part of electricity network operations. Networks are expected to regularly review their insurers and reinsurers, negotiate bespoke insurance products, chose to self-insure certain risks, or access shareholder/government or government self-insurance coverage, capital or guarantees.
- We observe based on our experience that live-line insulator washing is routinely undertaken by other networks where dust or salt accumulation on insulators leads to increased pole top fire risks.

Western Power considers the management of PPAPs is a new regulatory requirement created by a recent Court decision. However, we consider there is not necessarily a material change in the obligations for Western Power, and these remain comparable to the management practices of other Australian distribution networks for the following reasons:

- The Court decision relates to the obligations of Western Power in a 2014 bushfire event, which implies that the obligation has been managed by Western Power since that time.
- There is public reporting that Western Power has since chosen to take immediate disconnection of customers where its subcontractors have condemned a pole, or otherwise issuing a 30 day or 90 day defect notice prior to disconnection.[60]
- The Parkerville fire occurred in 2014 and the recent 2021 finding in the Supreme Court of WA – Court of Appeals found that Western Power had an existing duty to inspect the Private Point of Attachment pole and notify the customer if replacement was necessary.
- The addition of private pole inspections to the works program represents an operational shift in the management of private pole assets that are closest to customers – but the focus on safety is not dissimilar to Western Power's recent renewal of its overhead service wire population over the past 10 years under the significant 'twisties' replacement program.

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[60] For example, see: https://www.watoday.com.au/national/western-australia/perth-hills-residents-cut-off-as-western-power-cracks-down-on-decrepit-poles-20220602-p5aqmk.html; and https://memberarea.necawa.asn.au/Admin/ViewContentPage?uniqueName=private-power-pole-inspections-by-western-power-commence-18-october.

Given that the obligations previously existed, the actual risk to Western Power has not necessarily changed as a result of the recent Court decision. It could be argued that Western Power has been made more aware of the risk that it is taking in relation to its decision not to conduct private pole inspections of the PPOA pole as part of its network maintenance activities. As a result, Western Power is expected to reprioritise its maintenance program in the first instance to accommodate the higher risk activities within its historical allowances and accelerated the realisation of material efficiencies (such as those associated with the substantial ICT investment) to enable these benefits to fund maintenance work at the lower risk end of the spectrum. Importantly, the efficient delivery of this private pole inspection work would typically be integrated with the bushfire preparedness activities, vegetation management, pole inspection and general maintenance work program to maximise delivery efficiencies and minimise costs.

6.4.3 Conclusion

Given the above findings, we do not consider that Western Power's revised position on OPEX step changes is consistent with the base–step–trend OPEX forecasting approach or typical regulatory practice under incentive regulation frameworks. Therefore, we recommend that the three step changes are excluded from the AA5 total OPEX forecast.

7.0 PRODUCTIVITY GROWTH

7.1 Summary

The productivity growth factor is included within the trend component of the OPEX base–step–trend forecasting approach, which was proposed by Western Power and applied by the ERA in its draft decision.

The ERA's draft decision adopted our initial advice to set a productivity growth factor of 2 per cent per annum – based on trends in the AER's benchmarking data for NEM distribution networks available at the time.

Western Power is proposing a productivity growth factor of 0.5 per cent per annum – which is higher than its initial proposal of 0.25 per cent per annum. Western Power's justification of its Revised Proposal, based on advice from Synergies Economic Consulting, is difficult to reconcile against their initial position. Western Power now seeks to adopt a March 2019 AER decision that was informed by trends in the electricity industry and other broader sectors using what Synergies described as outdated data, rather than comparable NEM distribution businesses using the latest benchmarking data.

We do not consider there is a sufficient basis for the ERA to change its draft decision based on Western Power's new arguments.

We acknowledge making comparisons between Western Power and the NEM distributors based on reflective reporting periods is challenging – noting the productivity data is highly variable from year-to-year. Considerable judgement is required by the ERA to estimate what Western Power can reasonably achieve acting prudently and efficiently in AA5.

The most recent productivity trends of NEM distributors – using a range of estimates and comparisons – are more consistent with our previous recommendation compared to Western Power's Revised Proposal. A productivity growth factor of 2 per cent is squarely within the range of performance of six highly comparable network businesses (1.6–2.5 per cent), the five best performing NEM distributors (1.7–2.4 per cent) and all 13 NEM distributors (1.7–2.4 per cent), over 10- and five-year periods.

7.2 Western Power's initial proposal

Western Power's proposal included a productivity growth factor of 0.25 per cent per annum – which it said reflects expected industry-wide improvements in finding more efficient ways of delivering services, and is consistent with the AER's methodology for forecasting productivity growth.[61] This translated to a reduction of $14.3 million to Western Power's base OPEX for the AA5 period.

Western Power engaged Synergies to forecast OPEX productivity estimates for its AA5 proposal. Synergies used a Multilateral Total Factor Productivity model to generate productivity estimates using data from the AER's 2019-20 Benchmarking Regulatory Information Notices.[62] Synergies selected what it considered to be the five most comparable networks – namely, SA Power Networks, Powercor, AusNet Services, Essential Energy and Ergon Energy. Synergies stated these distributors have similar network characteristics to Western Power, including rural network segments.[63]

Based on an assessment of five and 10 years of data, combined with its scan of regulatory precedent, Synergies forecast productivity growth of between zero and 0.5 per cent per annum. Acknowledging there is considerable judgement around the appropriate productivity assumption, including because

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61 Western Power's initial proposal, p. 167.

62 Western Power's initial proposal, pp. 167–168.

63 Western Power's initial proposal, attachment 7.3, p. 39.

of its observed annual volatility, Synergies recommended a productivity growth factor of 0.25 per cent per annum – which corresponds to the mid-point of its identified range. Synergies stated the AER's current assumption of 0.5 per cent productivity growth[64] is at best an upper bound for the productivity trajectories of the five NEM comparators it considered are of most relevance to Western Power.[65]

Western Power adopted Synergies' recommendation in its initial proposal.

7.3 Engevity's initial advice

In our initial advice to the ERA, on balance, we considered Western Power should be able to target an efficiency improvement across the AA5 period of 2 per cent per annum. We weighed the following factors in forming this view:[66]

- The average productivity of the five distributors selected by Synergies in its initial advice increased – using more recent benchmarking data not available at the time of Western Power's initial proposal – to between roughly zero and 2.6 per cent per annum over a five- and 10-year period, respectively.
- We considered Western Power's spread of customers is highly comparable to Endeavour Energy's profile, which was not included in Synergies analysis. Endeavour Energy achieved an average productivity growth of 7 per cent per annum from 2016 to 2020, and 2 per cent per annum over 2006–20.
- Of the five networks selected by Synergies, only Powercor and SA Power Networks are at the efficiency frontier.[67] The average productivity of these two 'frontier distributors'[68] was between roughly zero and 4 per cent per annum over a five- and 10-year period, respectively.
- We considered there may be scope for Western Power to achieve greater OPEX efficiencies than what was included in its base OPEX forecast. Western Power's forecast had not identified additional CAPEX–OPEX trade-offs that are expected from its proposed SPS and AMI capex programs.
- Productivity changes for NEM transmission networks are less stable and do not show a strong trend over time relative to distribution OPEX productivity. So, we had not sought to rely on the transmission data.

We considered a productivity growth factor of 2 per cent per annum over AA5 is broadly consistent with Western Power's proposed approach to estimate the productivity growth factor using more recent benchmarking data, while distinguishing between movements in the efficiency frontier versus 'catch up'.[69]

The ERA broadly accepted our recommendation in the draft decision. The ERA found it is reasonable to expect a service provider efficiently minimising costs would seek to achieve a productivity factor of

64 See: AER, Forecasting productivity growth for electricity distributors, March 2019.

65 Western Power's initial proposal, attachment 7.3, pp. 39–40.

66 Engevity report to ERA, Attachments, August 2022 pp. 108–113.

67 We noted the AER considers the productivity growth factor should only capture the productivity growth that would be achieved by a distributor on the efficiency frontier – to control for the scope for other distributors' performance to include an element of catch-up productivity – so it bases its estimate on the highest ranked distributors in the NEM.

68 Synergies considered other frontier networks – Citipower and United Energy – were not comparable given they are Melbourne-based urban distributors with no rural network segments.

69 Engevity report to ERA, Attachments, August 2022 p. 112.

2 per cent per annum – delivering OPEX efficiencies more consistent with other network operators in Australia.[70]

7.4 Western Power's Revised Proposal

Western Power considers the choice of productivity growth can be misleading if sole or primary weight is placed on a single productivity estimation without considering a broad range of information. Western Power submits a range of recent productivity growth estimates that are relevant to Western Power's circumstances should be considered, including:[71]

- electricity and gas distribution networks
- electricity supply chain
- labour productivity
- water productivity
- international electricity productivity.

On the basis of this analysis undertaken by Synergies, Western Power proposes an OPEX productivity forecast of 0.5 per cent per annum for the 2022–27 period – noting that this is consistent with the AER's current OPEX productivity assumption used in its forecasting methodology.[72]

Further, Western Power considers it is absorbing several cost pressures, including: rising interest rates, inflation, tighter labour markets, supply chain disruptions, costs for the energy transformation program and related initiatives (such as the Change Control 5 program), and reforms including the EV Action Plan and WOSP. As such, Western Power states imposing a higher productivity factor than 0.5 per cent per annum would set an unrealistic productivity target.[73]

7.5 Engevity analysis

It is difficult to make direct like-with-like comparisons between Western Power and the NEM distributors. Estimating expected productivity growth for Australian distribution networks relies on judgement based on a range of relevant information.

We have considered the new arguments put forward by both Synergies and Western Power in its Revised Proposal, and the latest AER productivity data to form our final advice to the ERA.

7.5.1 Western Power does not reconcile inconsistencies in Synergies' recommendations

Western Power's approach to estimating the productivity growth factor, based on advice from Synergies, has changed significantly between its initial and Revised Proposals without reasonable justification.

Synergies initially argued against using the AER's March 2019 decision for forecasting productivity growth for electricity distributors because:[74]

- the AER's analysis used data only up to 2017 in its productivity review and this needs to be updated for the latest data

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70 ERA draft decision, attachment 6, p. 17.

71 Western Power's Revised Proposal, p. 88.

72 Western Power's Revised Proposal, p. 88.

73 Western Power's Revised Proposal, pp. 88–89.

74 Western Power's initial proposal, attachment 7.3, p. 37. Synergies explicitly recognises the AER's analysis was supplemented by estimates and forecasts from gas distribution productivity and labour productivity growth for utilities and other sectors.

- the AER's analysis of electricity distributors relied only on the top four ranked networks in the NEM, and it is unclear whether each of these networks is sufficiently comparable to Western Power to inform a robust productivity estimate.

Western Power accepted Synergies analysis in proposing productivity growth factor of 0.25 per cent per annum in its initial proposal.

Western Power now argues the AER's March 2019 decision should be applied by the ERA – that is, the AER's current OPEX productivity assumption used in its base-step-trend OPEX forecasting methodology– consistent with Synergies' analysis of 'industry practice'. Moreover, Western Power considers the productivity forecast should be informed by trends in the electricity industry and other comparable sectors.[75]

In support of its latest recommendation to Western Power, Synergies highlights the AER's reasoning for not relying on the OPEX productivity results 'deterministically' to estimate the productivity growth factor.

In context, the AER stated it would be ideal to rely upon consistent and reliable productivity data for the electricity distribution sector over the long term in forecasting the productivity growth factor.[76]

However, the AER considered this was not possible at the time due to the following factors:[77]

> … we examined electricity distribution productivity over 2011–2017. The OPEX productivity results suggests productivity in the range of 0.35 and 0.97 per cent. These estimates:
>
> - reflect a reasonable estimate of the productivity growth achieved by distributors in recent year, with limited effects of material step-changes and abnormal years
> - reflect the growth in the industry frontier, having excluded catch-up effects by focusing only on those distributors ranked in the top four
> - **incorporate 2017 data which is the most recent available data**
> - rely on a transparent methodology as set out in our 2018 annual benchmarking report and Economic Insights' further analysis.
>
> While these productivity estimates minimise the effects of regulatory changes and reflect more recent information, **the annual rate of productivity growth is based on a relatively short time period and a small sample of distributors used to proxy the frontier**. The resultant productivity growth rates varies significantly as the time period changes and as different distributors are selected.
>
> We also acknowledge that if we rely upon OPEX productivity growth from a small set of distributors sharing common ownership to forecast OPEX productivity growth, it **may reduce the incentives on the top four distributors to pursue productivity gains**. These distributors may also be able to influence future OPEX productivity results with their OPEX performances, and therefore the OPEX productivity forecasts set in subsequent periods.
>
> Given this, we consider that it is **not appropriate at this time to use OPEX productivity results deterministically** to forecast productivity going forward. It is appropriate to examine productivity trends more broadly, including over the long-term and in comparator sectors. This broader approach of drawing on a wider range of information sources is also consistent with the recommendations of the Australian Competition Tribunal (2016). [Emphasis added]

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75 Western Power's Revised Proposal, pp. 87–88.

76 AER, Forecasting productivity growth for electricity distributors, March 2019, p. 9.

77 AER, Forecasting productivity growth for electricity distributors, March 2019, p. 42. [Emphasis added]

Synergies finds, "this statement from the AER makes clear that observed OPEX productivity results are not to be relied upon deterministically in the way that Engevity has applied in its assessment of Western Power."[78] However, Synergies did not acknowledge the full context for the AER's findings, as provided above.

In proposing to apply the AER's previous methodology, Synergies and Western Power do not seek to reconcile:

- the more limited data available to the AER at the time of its March 2019 decision – the latest AER benchmarking report for electricity distributors allows for performance comparisons over a significantly longer time period, including four years of additional data (2018–21)
- AER concerns about creating perverse incentives for NEM distributors at the efficiency frontier – which do not apply to Western Power.

Western Power falsely states Synergies "considered a range of **recent** productivity growth estimates that are relevant to Western Power's circumstances."[79] In recommending to Western Power 0.5 per cent per annum based on the AER's March 2019 decision, Synergies did not attempt to update the relevant AER calculations – including for more recent electricity distributor performance data, time trends estimated in econometric models for gas distribution industry, and labour productivity forecasts for the utilities sector. Further, Synergies did not have regard to more recent regulatory precedents made in the water industry and overseas electricity distribution sectors.

We consider the AER's March 2019 decision does not necessarily represent its *current* OPEX productivity assumption, as suggested by Western Power. The AER is unlikely to rely on outdated 2011–17 data for its upcoming electricity distribution revenue determinations. Further:

- Although Synergies states it does not expect the AER will change its approach,[80] the AER had clarified its intention to apply its March 2019 decision up to the April 2021 Victorian distributor revenue determinations.[81]
- The AER said it would have considered updating the productivity factor **prior to 2021**, if it identified a significant change in the underlying economic drivers of OPEX that may affect electricity distributors' abilities to generate productivity gains.[82] Synergies does not acknowledge Western Power has proposed a major business transformation program in response to recent trends and changes in its broader operating environment – driven by government emissions reduction targets and market and technology developments, consistent with the experience of other Australian distribution networks.

In its most recent advice, Synergies appears to maintain its preference to base the productivity growth factor estimate on what it considered to be the five most comparable network businesses using the latest available data. Synergies states that the AER's approach based on its March 2019 decision "**remains valid as the upper bound** annual OPEX productivity forecast for Western Power in the AA5 period".[83] This language is consistent with Synergies initial advice that "**the AER's current assumption** of 0.5 per cent productivity growth **is at best an upper bound** for the recent productivity

78 Western Power's Revised Proposal, attachment 6.1, p. 17.

79 Western Power's Revised Proposal, p. 88. [Emphasis added]

80 Western Power's Revised Proposal, attachment 6.1, p. 17.

81 AER, Forecasting productivity growth for electricity distributors, March 2019, p. 11.

82 AER, Forecasting productivity growth for electricity distributors, March 2019, p. 11.

83 Western Power's Revised Proposal, attachment 6.1, p. 21. [Emphasis added]

trajectories of the five NEM comparators that we consider are of most relevance to Western Power."[84]

So, Synergies seems to contradict itself by now saying OPEX productivity results cannot be used deterministically to estimate the productivity growth factor. Indeed, Synergies initial advice used distributor productivity data of five NEM comparators to calculate a range of zero and 0.5 per cent per annum, based on an assessment of five and 10 years of data, and recommended 0.25 per cent per annum because it "corresponds to the mid-point of our identified range".[85]

Further, Synergies noted the AER's methodology of setting the productivity growth factor relied only on the top four ranked networks in the NEM. But Synergies considered these networks were not sufficiently comparable to Western Power to inform a robust productivity estimate.[86] Western Power now states the productivity catch-up for networks that are not amongst the best performing networks should not be imposed.[87]

Western Power did not reconcile these apparent contradictions in its Revised Proposal, and accepted Synergies analysis in now proposing a productivity growth factor of 0.5 per cent per annum.

7.5.2 Latest productivity data

Making comparisons between Western Power and the NEM distributors is complicated given the productivity data is highly variable. Considerable judgement is required. There is no single robust measure that can be relied on by the ERA. It is challenging to select reflective reporting periods, as highlighted by Synergies.[88]

While longer time periods using a ten-year average help to smooth out year-to-year variability, the five-year average captures more recent productivity trends and mirrors the length of the AA5 regulatory control period. Using data for other utilities and sectors can provide a useful cross-check, but the extent to which this data is comparable is questionable – especially if it does not reflect the current operating environment.

The productivity growth factor is meant to capture the productivity growth of a distributor on the efficiency frontier, as now recognised by Western Power in its Revised Proposal. But there is a limited sample of efficiency frontier networks that are comparable to Western Power.

We have re-calculated productivity trends using the latest AER benchmarking data for what we consider to be a broad and reasonable range of measures.[89] We continue to rely on the AER's OPEX partial factor productivity data, which provides a measure of OPEX productivity in electricity distribution – accounting for all OPEX inputs used by distributors (labour and non-labour) and considers multiple outputs delivered by the electricity distribution sector. We note the AER's concerns about using its productivity data prior to 2011.[90]

As shown in table 15 below:

- The average productivity of what we consider to be the six most comparable NEM distributors to Western Power – namely, AusNet Services, Endeavour Energy, Ergon Energy,

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84 Western Power's initial proposal, attachment 7.3, p. 40. [Emphasis added]

85 Western Power's initial proposal, attachment 7.3, p. 40.

86 Western Power's initial proposal, attachment 7.3, p. 37.

87 Western Power's Revised Proposal, p. 88.

88 Western Power's Revised Proposal, attachment 6.1, pp. 19–20.

89 See: Annual Benchmarking Report - Distribution and Transmission 2022 | Australian Energy Regulator (aer.gov.au)

90 AER, Forecasting productivity growth for electricity distributors, March 2019, p. 41.

Essential Energy, Powercor and SA Power Networks – is 1.6 and 2.5 per cent per annum over a 10- and five-year period, respectively.

- The average productivity of the five most efficient NEM distributors – namely, Powercor, CitiPower, SA Power Networks, TasNetworks and United Energy – is 1.7 and 2.4 per cent per annum over a 10- and five-year period, respectively. The AER highlights these five distributors as the top performers in terms of OPEX efficiency scores over 2012–2021.[91] We consider they can be reasonably used as a proxy for the efficiency frontier – noting the selection of the efficiency frontier can be based on several factors, depending on the purpose.[92]
- The average productivity of all 13 NEM distributors is 1.7 and 2.4 per cent per annum over a 10- and five-year period, respectively.

Table 15 - Percentage Change in DNSP Multilateral OPEX Partial Productivity Indexes, 2012–2021

Distributor	2012 – 2021	2017 – 2021
Comparable networks	1.6 per cent	2.5 per cent
Efficiency frontier distributors	1.7 per cent	2.4 per cent
All NEM distributors	1.7 per cent	2.4 per cent

Source: AER 2021 Distribution Annual Benchmarking Report and Supporting Data Files.

Note: Calculations are based on the point-to-point change in productivity divided by the number of years.

7.5.3 How incentive regulation helps the ERA manage incomplete information about efficient costs

In setting the productivity growth factor, it is not the role of the ERA to undertake a detailed review of Western Power's OPEX activities and programs to uncover potential inefficiencies in the way it operates its network.

Energy regulation in Australia is intended to be incentive-based where possible. The base–step–trend model provides incentives for Western Power to reveal its efficient costs, as discussed in section 6.3. Economic benchmarking provides a top-down assessment of whether an adjustment to base OPEX is required, if there is evidence of material inefficiencies.

These economic tools allow the ERA to:

- avoid the need to undertake a bottom-up, detailed assessment for which the ERA would have a significant information disadvantage
- minimise the risk of creating mixed incentives and shifting the regime towards 'cost of service' regulation.[93]

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[91] AER, Annual Benchmarking Report, Electricity distribution network service providers, November 2022, p. 31.

[92] AER, Forecasting productivity growth for electricity distributors, March 2019, pp. 39–42.

[93] Cost of service regulation, as its name implies, compensates regulated businesses for the costs incurred to provide services. If a business reduces its costs, the benefits of cost efficiency accrue to consumers in the form of lower prices, not to the business as profits. On the other hand, if costs increase then so do prices. Cost of service regulation creates an environment that provides greater assurance to regulated businesses that investments in sunk assets will be recovered. However, a pure cost of service approach provides low-powered incentives for cost reductions because actual costs are fully passed through to consumers.

Our previous report found Western Power appears to be a relatively efficient network service provider compared to other Australian networks.[94] Therefore, an adjustment to base OPEX was not recommended.

That does not mean the ERA should adopt a productivity growth factor of zero for AA5, as suggested by Synergies.[95] Rather, it reinforces the need to place greater weight on the estimated productivity growth that is expected to be achieved by distributors close to or on the efficiency frontier – given it can be assumed there is less scope for Western Power's performance to include an element of 'catch-up productivity'.

We note the level of the productivity growth factor does not necessarily have a significant influence on Western Power's incentives – especially if the target is set based on factors outside of its control. The drive to maximise shareholder returns should push Western Power to become more efficient and productive over time. Any marginal change in the efficiency of Western Power will be rewarded or penalised regardless of the productivity growth factor.

7.5.4 Conclusion

Overall, we do not consider there is a sufficient basis for the ERA to change its draft decision.

The key questions for the ERA in determining the productivity growth factor is what Western Power can reasonably achieve acting prudently and efficiently in AA5, and whether the total OPEX forecast satisfies the Access Code requirements.

Our draft advice of a productivity growth factor of 2 per cent per annum balanced several factors, as discussed in section 7.3 above.

The most recent productivity trends of NEM distributors, using a range of estimates and comparisons from the AER's November 2022 benchmarking report, is more consistent with our previous recommendation compared to Western Power's new proposal of 0.5 per cent per annum.

Western Power's Revised Proposal is significantly lower than the range of estimates of comparable NEM distributors. A productivity growth factor of 2 per cent is squarely within the range of performance of six highly comparable network businesses (1.6–2.5 per cent), the five best performing NEM distributors (1.7–2.4 per cent) and all 13 NEM distributors (1.7–2.4 per cent), over a 10- and five-year period (see table 15 above).

Further, as discussed above, Western Power has changed its position without reconciling several significant inconsistencies, including within Synergies advice. In our view, this undermines the credibility of Western Power's new arguments.

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94 Engevity report to ERA, Executive summary, August 2022, pp. 29–30.

95 Western Power's initial proposal, attachment 7.3, p. 41.