Economic Regulation Authority

Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27

Attachment 6: Operating expenditure

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Note

This attachment forms part of the ERA's draft decision on proposed revisions to the access arrangement for the Western Power Network for the fifth access arrangement period (AA5). It should be read with all other parts of the draft decision.

The draft decision comprises all of the following attachments:

Draft decision on proposed revisions to the access arrangement for the Western Power network 2022/23 – 2026/27 – Decision Overview

Attachment 1 – Price control and target revenue

Attachment 2 – Regulated asset base

Attachment 3A – AA4 capital expenditure

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1. Summary

This attachment deals with operating expenditure.

Western Power is proposing an increase in operating expenditure for AA5 compared to AA4. Western Power has assumed annual efficiency savings of 0.25 per cent offset by higher levels of cost increases over the period.

The ERA's draft decision is based on annual efficiency savings of 2 per cent and lower cost increases than proposed by Western Power.

Summary of draft decision

- Removed the proposed increase in costs for the silicone treatment program as they are not required under the Energy Safety Order and industry guidelines recommend alternative approaches.
- Required that the costs of decommissioning overhead lines are treated as capital expenditure and depreciated over one year. This will leave target revenue unchanged for AA5 but will enable the costs to be included in the investment adjustment mechanism for undergrounding and stand-alone power systems so that any difference between forecast and actual decommissioning can be trued up at the next access arrangement.
- Removed the forecast increase in circuit length in the distribution network growth escalation factor to be consistent with Western Power's plans to convert parts of the network to stand-alone power systems.
- Retained the AA4 method that requires the transmission growth escalation factor to be based on the number of transmission connections.
- Removed the growth escalation factors from corporate and indirect costs.
- Applied a productivity factor of two per cent per annum to operating expenditure and indirect costs. This requires Western Power to deliver operating expenditure efficiencies more consistent with other network operators in Australia, as well as ensuring that an allowance for efficiencies for the AA4 investment and efficiencies from investment in new and enhanced systems during AA5 are embedded in the forecast.

Table 1 below compares the ERA's draft decision with Western Power's proposed operating expenditure.

Table 1: Operating expenditure – Comparison of draft decision and Western Power's proposal (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Western Power proposed	423.9	434.9	434.3	440.1	449.5	2,182.7
ERA draft decision	411.7	414.4	403.9	400.6	401.3	2,032.0

Source: Western Power and ERA target revenue model

The reasons for the ERA's draft decision on forecast operation expenditure and details of required amendments are set out in this attachment.

2. Regulatory requirements

Section 6.40 of the Access Code provides for approved total costs and target revenue to include an amount for forecast non-capital costs (operating costs) for the access arrangement period.

Forecast operating costs must only include those costs that would be incurred by a service provider efficiently minimising costs. This is defined in the Access Code as meaning the service provider incurs no more costs than would be incurred by a prudent service provider, acting efficiently in accordance with good electricity industry practice seeking to achieve the lowest sustainable cost of delivering services, and without reducing service standards below the service standard benchmarks set for each covered service in the access arrangement or contract for services.

An extract of sections of the Access Code relevant to forecast operating expenditure is included in Appendix 1.

3. Western Power's proposal

Western Power has forecast that operating expenditure of $2,183 million will be required for it to operate and maintain its network over the AA5 period.

Western Power has used the "base-step-trend" method to forecast operating expenditure. It has used the penultimate year of AA4, 2020/21 to establish what it considers to be its efficient recurrent base operating expenditure. It has then forecast discrete step changes and changes in output and cost input trends over the AA5 period to forecast operating expenditure for each year of AA5. Table 2 summarises the results of Western Power's forecasting process.

Table 2 AA5 proposed operating expenditure (real $ million at June 2022)

Expenditure	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Recurrent network base costs	348.1	348.1	348.1	348.1	348.1	1,740.5
Step changes	21.9	21.1	20.9	20.7	20.3	104.9
Total recurrent network costs	370.0	369.2	369.0	368.8	368.4	1,845.4
Network growth escalation	5.1	7.1	10.7	13.8	16.2	52.9
Efficiency	-0.9	-1.9	-2.8	-3.8	-4.8	-14.3
Non-recurrent network costs	10.9	18.1	13.4	13.2	16.9	72.5
Labour cost Escalation	4.3	6.5	8.5	10.6	12.9	42.7
Expensed indirect network costs	34.7	35.8	35.5	37.5	39.9	183.4
Total	423.9	434.9	434.3	440.1	449.5	2,182.7

4. Submissions

Submissions on operating expenditure were received from Perth Energy, Synergy, WALGA and the WA Expert Consumer Panel. Matters raised included:

- Concerns about lack of information on the proposed expenditure.
- Questions about how Western Power benchmarked against other network service providers and whether it had included sufficient productivity improvements in its proposal.
- Concerns about the proposed changes to washing and applying silicone to insulators.
- Concerns about the LED streetlight replacement strategy
- Questions about whether the proposed expenditure to support market reforms was related to the provision of covered services.
- Questions about whether expenditure for alternative options should be included.
- A view that the real labour cost increases should be set no greater than the assumed rate of productivity growth.

The matters raised are included in the ERA's considerations below.

5. Considerations of the ERA

The process adopted by the ERA in considering the forecasts of operating expenditure has been to:

- Assess the extent to which Western Power's proposed recurrent network base costs would be incurred by a service provider efficiently minimising costs, consistent with the requirements of section 6.40 of the Access Code.
- Assess whether Western Power has provided adequate justification that forecast trends and step changes in the level of operating expenditure over AA5 are consistent with those that would be incurred by a service provider efficiently minimising costs

The ERA's technical consultant Engevity provided advice on the efficiency of Western Power's proposed operating expenditure and undertook a benchmarking exercise using the Australian Energy Regulator's (AER) benchmarking models and data from the NEM network service providers.

5.1 Efficient base year operating expenditure

The ERA has considered whether the actual operating expenditure for AA4 is consistent with a service provider efficiently minimising costs and therefore constitutes a relevant cost base against which forecast operating expenditure for AA5 can be assessed.

The ERA has assessed the efficiency of Western Power's base year (2020/21) operating expenditure by:

- Verifying records of actual operating expenditure for the AA4 period.
- Benchmarking against operating expenditure reported by other network service providers in Australia.
- Reviewing the incentives for Western Power to minimise its operating expenditure.
- Reviewing the base year operating expenditure line items (at a high level) for reasonableness.

Verification of operating costs in AA4

In accordance with the ERA's Guidelines for Access Arrangement Information, Western Power has provided regulatory accounts that reconcile costs of regulated activities with a set of base accounts for the business. A comparison of claimed operating costs with recorded operating costs are shown in Table 3 below.

Table 3: Reconciliation of claimed operating expenditure for AA4 with recorded operating expenditure for Western Power ($ million nominal)

	Base Account	Adjustments	Regulatory Account	Claimed non-capital costs
Transmission 2017/18	97.7	5.4	103.1	103.1
Transmission 2018/19	96.1	1.3	97.4	97.4
Transmission 2019/20	119.8	1.1	120.9	121.4
Transmission 2020/21	122.0	0.2	121.8	121.8

	Base Account	Adjustments	Regulatory Account	Claimed non-capital costs
Transmission 2021/22*				114.8
Distribution 2017/18	281.0	38.5	319.5	319.5
Distribution 2018/19	273.2	3.4	276.6	276.6
Distribution 2019/20	308.4	2.9	311.3	311.3
Distribution 2020/21	305.3	0.8	306.1	306.1
Distribution 2021/22*				338.5

** Western Power 2021/22 financial results are not yet available.*

There is a small difference ($0.5 million) in transmission expenditure for 2019/20 due to an input error in Western Power regulated revenue model. This will be corrected in the final decision.

Adjustments over the AA4 period that have been necessary to create the annual regulatory accounts include:

- Fleet depreciation to align Western Power's statutory accounting disclosures with its regulatory accounting disclosures. To achieve this, the unregulated fleet depreciation is disclosed as operating expenditure costs in the regulatory financial statements and not depreciation and amortisation.
- Aligning Western Power's statutory capital additions with the ERA's AA4 decision regarding statutory capital expenditure that does not meet the new facilities investment test, including amounts relating to:
  - Intellectual property for work completed in preparation for transition to the national regulatory regime.
  - Wood pole emergency replacements
  - Provision for environmental and rehabilitation costs.
- Other operating expenditure costs that do not meet the non-capital costs requirements of the Access Code and which cannot be expensed to the regulatory profit and loss account.

Western Power's regulatory accounts are audited for Western Power by the Office of the Auditor General.

The ERA is satisfied that the regulatory accounts provide a true and correct indication of operating costs in the AA4 period.

Benchmarking Analysis

The ERA engaged Engevity to benchmark Western Power's performance against other service providers utilising the AER's benchmarking methods and data drawn from the AER's benchmarking report and averaged over five years.

Engevity's analysis demonstrated that Western Power performs relatively well in terms of expenditure against its peers in the NEM. However, it does not perform as well in terms of service performance, particularly for rural customers.

A detailed discussion of Engevity's findings is at section 5.7.1 of Engevity's report to the ERA.

Incentives to minimise operating expenditure

Western Power's regulatory framework provides incentives for it to minimise its operating expenditure and achieve efficiencies greater than those included in the approved target revenue.

During an access arrangement period, Western Power keeps the benefit of any under expenditure compared with the level of expenditure forecast in the access arrangement decision. The gain sharing mechanism provides further opportunities for Western Power to retain the benefit of any under expenditure into the next access arrangement period. The gain sharing mechanism ensures Western Power retains the benefit of any under expenditure for five years regardless of which year the under expenditure occurred.

These measures all contribute to giving Western Power an incentive to minimise its costs.

Base year network operating expenditure

Western Power has used the operating expenditure for 2020/21, the penultimate year of AA4 as the base year for its AA5 forecasts because that is the most recent year for which audited results are available.

Western Power has made the following adjustments to its 2020/21 actual costs to establish its AA5 recurrent network base cost of $348.1 million.

- Removed $20 million of revenue associated with non-revenue cap services.
- Removed indirect costs of $42.8 million. These have been removed because Western Power forecasts indirect costs separately and then allocates them between capital expenditure and operating expenditure.
- Removed non-recurrent expenditure that is not reflective of ongoing operational expenditure requirements of $14.6 million, including:
  - Design costs of $5.6 million for a project that did not proceed and which were subject to a customer contribution.
  - Actuarial adjustments of $4.2 million that were materially above the adjustment amount averaged over the previous five years.
  - Correction of unintentional underpayments of $1.8 million identified in an internal underpayments review.
  - Removal of $3.1 million that is associated with implementing phase one of the energy transformation program.
- Rolled forward the base year to account for inflation in the final year of the AA4 period.[1]

Western Power's recurrent network base costs of $348.1 million break down as follows:

- $194.1 million of operating expenditure on the distribution network
- $60.6 million of operating expenditure on the transmission network
- $93.4 million of recurring corporate operating expenditure.

[1] Western Power states it engaged Synergies to determine the inflation rate for 2021/22. Synergies determined the inflation rate for 2021/22 to be 1.75 per cent based on the most recent WA Treasury forecast. The regulated revenue model used an inflation factor of 1.84 per cent based on the AA4 forecast inflation.

A review of operating expenditure by regulatory category was undertaken by Engevity who noted that, apart from corporate costs, Western Power's total operating expenditure appeared consistent with other similar networks. However, Western Power's corporate costs were relatively high and moving further away from comparable AER regulated Network Service Providers over the term of AA5.[2]

Taking account of the information put forward by Western Power, the benchmarking undertaken by the technical consultant and the regulatory incentives for efficient expenditure, the ERA has accepted Western Power's proposed base year expenditure.

5.2 Forecast changes in operating expenditure during AA5

Western Power's forecast changes in operating expenditure over the AA5 period have been considered in the following order:

- Step changes
- Network growth escalation
- Non-recurrent network costs
- Productivity improvements
- Indirect costs
- Labour cost escalation

5.2.1 Step Changes

Western Power's proposed step changes are set out in Table 4 below.

Table 4: Proposed step changes (real $ million at June 2022)

Step change	Description	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Repair streetlight faults	Includes LED replacement.	4.5	4.5	4.5	4.5	4.5	22.5
DSO capability	Develop the necessary internal capability within Western Power to Operate its DSO function as stipulated in the DER roadmap, including processes to ensure compliance of new DER devices connecting to the network meet technical standards	4.4	4.4	4.4	4.4	4.4	22.0
Meter reading	Less manual meter reading as a result of the acceleration of the AMI deployment.	(0.8)	(2.1)	(2.8)	(3.6)	(4.5)	(13.9)

[2] Engevity Final Advice (August 2022), Attachment 7, p. 82.

Step change	Description	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Silicone treatment program	Changes to the silicone treatment program requiring the line to be de-energised	5.3	5.3	5.3	5.3	5.3	26.4
Digital substation	Support for installation of devices and additional resources to analyse and prosses the data associated with new digital substation program	1.0	1.0	1.0	1.0	1.0	5.0
SCADA and Tele-communications	Cyber security, SPS and AMI implementation	3.9	3.9	3.9	3.9	3.9	19.5
SPS maintenance	Inspections and emergency response aligned with increase in SPS volumes	0.2	0.7	1.3	1.8	2.4	6.4
Governance and safety assurance	Increased Safety, Environment, Quality & Training (**SEQT**) training program & increased focus on compliance & governance	0.8	0.8	0.8	0.8	0.8	3.8
Light Detection and Ranging (**LIDAR**) program	New strategy to survey one-quarter of the network each year rather than the full network each 3-4 years. Shifted from non-recurrent to recurrent expenditure	1.2	1.2	1.2	1.2	1.2	6.1
Distribution power quality monitoring	New system to be developed to improve data accessibility for the low voltage network's power quality meters	0.4	0.4	0.4	0.4	0.4	2.2
High Voltage injection unit and emergency response generator	New strategy to deploy additional emergency response generators as part of fault response	1.0	1.0	1.0	1.0	1.0	5.0
Total value of step changes		**21.9**	**21.1**	**20.9**	**20.7**	**20.3**	**104.9**

Source: Western Power data

Stakeholder submissions raised the following specific concerns about the proposed step changes:

- WALGA considered the options assessment by Western Power for streetlighting LED replacements was deficient in that the published assessment only identified two options, replace like for like (which is not feasible as the globes cannot be procured or imported) and the proposed reactive replacement with LED globes. It noted the lifecycle cost and performance of a range other options had not been demonstrated. It was concerned that the approach is “piecemeal” and had not been rigorously and independently verified to provide the lowest lifecycle costs. WALGA was also concerned that the quality of the lighting outcomes resulting from the implementation of Western Power’s LED replacement strategy had not been demonstrated.

- Silicone treatment program
  - Perth Energy was concerned about the change in approach and stated that supply reliability and Western Power’s response to interruptions were critical performance indicators. Perth Energy relayed opinions from its customers that Western Power’s response to outages caused by pole-top fires was slower than was considered reasonable.
  - WALGA was concerned that the proposed reduction in the volume of silicone treatments and the increased cost of these treatments due to the requirement to apply the treatment only on de-energised lines will lead to a decrease in network performance.
  - Given the cost, and the implications for consumer supply, the WA Expert Consumer Panel considered that an independent review of the new maintenance process was required, including the consideration of whether methods used by other utilities such as standby generators and temporary bypasses could be used to conduct the work with ‘live-lines’.
- Synergy considered the step changes in operating expenditure for DSO capability and SCADA and communications is only efficient if it enables alternative options as a substitute for higher capital expenditure with net savings achieved overall. In any case, Synergy questions whether funding to develop new capabilities, systems and strategies such as DSO, digital substations, LiDAR programs, new data accessibility systems and additional response generators should be funded through recurrent revenue.

Engevity advised that Western Power had not provided sufficient information to demonstrate that the proposed step changes are efficient expenditure and that any offsetting savings have been incorporated in the proposal. Its findings were as follows:

- **Streetlight repairs ($4.5m p.a):** Additional volumes of streetlights to be serviced. Western Power has not provided evidence to demonstrate the proposed cost is efficient.
- **DSO capability ($4.4m p.a.):** Western Power has not provided evidence to demonstrate the proposed cost is efficient.
- **Meter Reading ($4.5m p.a. by 2026/27):** While it is clear savings can be achieved by remote readings rather than manual reads, Western Power has not provided evidence to verify the forecast saving.
- **Silicone Treatment Program ($5.3m p.a.):** This program was justified in AA4 and has increased in cost due to the decision to conduct the procedure while de-energised which will incur substantially higher switching and planning costs in addition to lowering the daily unit rate of completions. [Engevity] note that the move away from live line work is not required under the Energy Safety Order 01 – 2021 which instead recommends improved equipment testing, compliance and work practices for live line insulator washing. This is largely consistent with the Victorian Electricity Supply Industry guidelines[3] and recent awareness publications involving

[3] Victorian Electricity Supply Industry, VESI Fieldworker Handbook, updated 2008, pp. 15-16.

washing equipment condition[4]. On this basis, [Engevity] do not consider that the step change is efficient.

- **Digital Substation ($1m p.a.):** The concept of such substations is well known in other utilities. Details relating to Western Power's planned implementation are not clear beyond equipment condition monitoring. Condition monitoring may prevent failures and assist in overall system performance. There may be savings in the reactive and planned maintenance categories. However, these targeted savings are not noted by Western Power[5].
- **SCADA & Telecommunications ($3.9m p.a.):** Both programs of expenditure are coupled with major CAPEX spends proposed in the AA5 period. Additionally, they build on previously approved programs from AA4. Western Power has not provided evidence to demonstrate that the proposed cost is efficient.
- **SPS Maintenance ($2.4m p.a. by 2026/27):** Cost estimations here are seen to ramp up reflecting the ambition to install approximately 1,800 SPS units in the AA5 period. Total estimated expenditure is projected to be in excess of $6.4M with built-in additional expenditure planned for the next period. While the strategy is self-evident in terms of reliability improvement it provides Western Power with several OPEX savings in the areas of pole maintenance, replacement, line patrols, fire mitigation, emergency response and line hardware maintenance. It is not clear if the estimates are net of these benefits.
- **Governance & Safety Assurance ($0.8m p.a.):** Engevity has examined these programs and it appears that much of the proposed AA5 activity is consistent with broad industry practice.
- **LiDAR program ($1.2m p.a.):** LiDAR is a sophisticated inspection methodology used by the majority of DNSP's and TNSP's as a cost-effective way to inspect geographically spread assets. The proposal here is for additional costs to increase the frequency of inspections. This should result in improvements in reliability and cost savings associated with corrective maintenance, but these do not appear to have been included in the proposal.
- **Power Quality ($0.4m p.a.):** Large local demand variations attributable to local generation will expose Western Power connections to unacceptable voltage variations and increasingly power quality issues. Investments in Power Quality monitoring are prudent and necessary. At a system level Western Power is investing heavily in control and monitoring equipment (e.g., AMI) as well as SCADA in order to manage these issues. While the overall strategy seems necessary it is not clear how the information will be focused, and the measured effects managed in real time. Nor is it clear how the OPEX associated with the initiative will be offset if at all by actions taken as a result of the information gained.
- **High Voltage Emergency Generator ($1m p.a.):** In recent periods many DNSP's have utilised High Voltage generators to provide local network support in the event of outages or as a temporary augmentation to local load carrying capacity. It is assumed that this is the Western Power strategy. Such equipment is available from the market on a hire basis, and it appears that Western Power intends to pursue this strategy along with an ownership strategy. Long term supply contracts with service providers may be more efficient.

4 Victorian Electricity Supply Industry, VESI HV Live Work Committee & VESI Work Practices Committee – Awareness Bulletin Live Work Equipment. A copy of this document can be found here.

5 In some cases, the benefits from condition monitoring will not be realised until the equipment develops faults or deterioration indicators. As this typically does not occur until later in the asset life, the monitoring the condition of the more reliable newer assets that have communications capabilities is of limited immediate benefit compared to the older plant with greater accumulated wear from operation and deterioration from environmental conditions.

ERA assessment

The assessment of the proposed step changes has been difficult due to limited information to demonstrate that the proposed step changes are efficient and that any offsetting savings have been incorporated.

The ERA has considered some specific matters below before setting out its overall view.

Repair streetlight faults

The repair streetlight faults activity is the non-routine repair of streetlight faults and predominantly responds to customer reports of faulty streetlights. Streetlights that have failed in service are identified by the public or workforce and faults are remediated.

As part of this, Western Power has developed a strategy to manage a transition to LED globes and luminaires in line with the cessation of the use of mercury vapour as per the Minamata Convention on Mercury.

The strategy aims for 100 per cent LED streetlights by 2029 (as compared to 3 per cent on 30 June 2020), which will lower carbon emissions and streetlighting energy costs. Replacing mercury vapour globes with LED involves a higher material cost, with the added benefits of reducing maintenance expenditure due to a longer life of globes, reduced energy consumption and better environmental outcomes.

Western Power states that it assessed various options to address the identified need in developing the step change forecast. It considered the assessment demonstrated that reactive replacement of streetlights with LED globes is the most cost-effective option.

In relation to the concerns raised by WALGA about streetlights, the ERA has amended the streetlighting reference service to require Western Power to ensure it meets current streetlighting standards if it changes the type of luminaire.[6] This should address WALGA's concern that Western Power may install luminaires that do not meet current streetlighting standards.

Converting streetlights to LED is an important component of Western Power's plans to reduce its carbon emissions as well as meet its obligations under the Minamata Convention. WALGA raised concerns that the reactive approach Western Power has chosen does not have the lowest lifecycle cost. As set out above, the ERA has required Western Power to ensure it meets current streetlighting standards if it changes the type of luminaire installed. Western Power will need to review its planned strategy if it was not based on meeting current streetlighting standards and ensure that the option it has chosen has the lowest lifecycle cost.

Required Amendment 1

Provide evidence that the proposed reactive replacement of streetlights with LED globes will meet current streetlighting standards and has the lowest lifecycle cost.

Silicone treatment program

To reduce the likelihood of pole top fires, Western Power applies silicone grease on insulators periodically on its distribution overhead network. Historically, the silicone application process was applied while the line was energised. A review of work practices undertaken in 2020/21

6 There are two standards identified by WALGA in its submission: AS/NZS 1158 - Pedestrian Area Lighting Standard; and AS/NZS 4282 – Control of the obtrusive effects of outdoor lighting.

determined that the application of silicone treatments would only be undertaken on deenergised lines. Consequently, the AA5 proposal includes lower volumes of silicone treatments compared to AA4 due to the requirement to get planned outages for silicone treatment on de-energised lines. The unit cost for silicone treatments is higher as a result of the change in work practice.

The ERA's technical consultant advised that the Energy Safety Order issued following an incident in 2020 did not require Western Power to de-energise lines for silicone treatment and that industry guidelines recommend alternative approaches.

In addition to the increased costs, stakeholders were concerned the proposed reduction in the volume of silicone treatments due to the requirement to apply the treatment only on de-energised lines will lead to a decrease in network performance.

Taking account of stakeholder submissions and the technical consultant advice, the ERA has removed the proposed step change for the silicone treatment program. Given the implications for customer supply, the ERA expects Western Power will review its work practices as suggested by the Expert Consumer Panel to enable it to work safely with "live-lines".

Overall

As identified in Synergy's submission, the proposed step changes include items relating to transformation programs. The ERA considers it is important to ensure that Western Power can respond to the rapidly evolving technologies and more frequent and severe weather events from a changing climate.

On balance, the ERA has accepted the proposed step changes (apart from the silicone treatment program) for inclusion in the forecast capital expenditure.

Required Amendment 2

Remove the proposed step change in operating expenditure for the silicone treatment program.

5.2.2 Network Growth Escalation

Western Power has proposed that its recurrent operating expenditure forecasts for AA5 be adjusted for the forecast growth in the customer base and the physical size of the transmission and distribution networks.

Western Power's proposed network growth escalation factors are set out in Table 5.

Table 5: Western Power proposed network growth escalation factors

Expenditure	Weighting	2022/23	2023/24	2024/25	2025/26	2026/27
Distribution						
Customer Numbers	55.70%	1.50%	1.52%	1.50%	1.49%	1.49%
Circuit Length	15.50%	-0.27%	-0.20%	1.07%	0.94%	-0.34%
Annual average growth in highest maximum demand	28.80%	0.00%	0.00%	0.00%	0.00%	0.00%
Distribution Growth	**100%**	**0.80%**	**0.82%**	**1.00%**	**0.97%**	**0.78%**
Transmission						
Customer Numbers	24.10%	1.50%	1.52%	1.50%	1.49%	1.49%
Circuit Length	49.30%	0.60%	-1.33%	1.02%	-0.22%	-0.22%
Annual average growth in highest maximum demand	26.60%	0.00%	0.00%	0.00%	0.00%	0.00%
Transmission growth	**100.00%**	**0.66%**	**-0.29%**	**0.87%**	**0.25%**	**0.25%**

Source: Western Power data

Western Power has also applied growth escalation to corporate costs and indirect costs.

The forecast values for the circuit length distribution scale escalation factor proposed by Western Power increase over the AA5 period. This forecast conflicts with Western Power's plan to remove lines as a result of the installation of SPS systems over the period.

For the draft decision, the ERA has removed the circuit length element to be more consistent with Western Power's plans to convert parts of the network to stand-alone power systems.

Required Amendment 3

Amend the circuit lengths in the distribution network growth escalation factor to be consistent with Western Power's plans to convert parts of the network to stand-alone power systems.

For the transmission growth factors, Western Power has proposed a change to the AA4 method for customer numbers. For AA5 Western Power has proposed that the total number of end-use customers should be used instead of the number of transmission connections.

The ERA does not consider that total customer numbers are more closely aligned with transmission related recurrent expenditure than the number of transmission related connections. Engevity has advised that adopting this change would also lead to a one-off step up in growth.

For the draft decision, the ERA has retained the method approved for AA4.

Required Amendment 4

Amend the customer numbers transmission network growth escalation factor to use the number of transmission connections.

Western Power also applied growth escalation to corporate costs. The ERA considers business support activities such as information technology, levies, fees and insurance are not proportional to growth in service outputs that may result from changes in customer demand. Consequently, no growth escalation should be applied to corporate costs.

Required Amendment 5

Remove growth escalation factors from corporate costs.

5.2.3 Non-recurrent network costs

Western Power forecasts it will spend $72.5 million of non-recurrent operating costs during the AA5 period.

Table 6: AA5 proposed non-recurrent costs (real $ million at June 2022)

Category	Activity	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 total
Transmission	66 kV line removal	2.3	4.9	0.1	0.0	0.0	7.4
Corporate	Regulatory Reform Program	3.7	0.4	0.0	0.0	0.0	4.1
Distribution	Decommissioning of distribution overhead line	4.9	12.7	13.3	13.2	16.9	61.0
Total non-recurrent		**10.9**	**18.1**	**13.4**	**13.2**	**16.9**	**72.5**

Source: Western Power data

In relation to the two items associated with the removal of overhead lines, there is a risk that the decommissioning may not go ahead at the dates planned. The regulatory framework does not enable differences in operating expenditure to be adjusted at the next access arrangement period. This could result in customers paying for decommissioning that does not occur. In contrast, the opening regulated asset base is adjusted at each access arrangement review to reflect actual capital expenditure during the previous period so ultimately only actual expenditure is passed through to customers.

With the planned levels of undergrounding and standalone power systems over AA5 and future regulatory periods, costs associated with the removal of overhead lines are likely to be significant. The ERA considers the decommissioning expenditure associated with the removal of overhead lines can be better managed in the regulatory framework if it is included in the capital costs of the project that leads to the need to remove the lines.

Treating the expenditure as part of the capital cost of the project will ensure that customers ultimately pay only for decommissioning expenditure that is incurred. Depreciating such expenditure over one year will ensure there is no difference in forecast target revenue regardless of whether it is treated as operating expenditure or capital expenditure. In the case of the East Perth substation, this would also better ensure that the decommissioning costs are netted off against any payment for the land.[7]

As there is no difference in target revenue, for the purposes of the draft decision the ERA has not adjusted operating expenditure. An adjustment to transfer it to capital expenditure will be made in the final decision.

Required Amendment 6

Decommissioning costs associated with the removal of overhead lines should be included in the capital costs of the project that leads to the need to remove the lines and should be depreciated over one year.

The ERA has not adjusted Western Power's forecast costs for continuation of the regulatory reform program.

5.2.4 Productivity improvements

Western Power has incorporated a productivity improvement of 0.25 per cent per year in its forecast operating expenditure. Western Power engaged Synergies to forecast operating expenditure 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. Synergies selected five networks most comparable to the Western Power Network for this analysis: SA Power Networks, Powercor, AusNet Services, Essential Energy and Ergon Energy.

Based on an assessment of five and 10 years of data, Synergies forecast productivity growth of between 0 and 0.5 per cent per annum.

Western Power applied the average of the forecast productivity growth calculated by Synergies, which results in a 0.25 per cent per annum productivity adjustment over the AA5 period.

Submissions queried whether Western Power had included a reasonable productivity factor in its proposal:

- The WA Expert Consumer Panel submitted that it had not seen evidence of an ongoing, strong focus on productivity improvement. It noted that the forecast efficiency trend of $14 million is relatively low when compared with the level of operational expenditure over AA5 and recommended seeking relevant benchmark information from other jurisdictions.

The ERA's technical consultant reviewed the analysis presented by Synergies and relied on by Western Power to establish its proposed annual efficiency value. Engevity was able to access more recent benchmarking data and to review the assumptions and methods applied by Synergies to arrive at its proposed range. Based on the updated data available, the average productivity of the five distribution networks assessed by Synergies is between 0 and 2.6 per cent per annum.

Energies also noted that Synergies had not fully adopted the AER's approach. The AER considers the productivity growth factor should only capture the productivity growth that would

[7] Proceeds from regulated asset disposals are deducted from the regulatory asset base.

be achieved by a distributor on the 'efficiency frontier', so it bases its estimate on the highest ranked distributors in the NEM. This helps to control for the scope for other distributors' performance to include an element of 'catch-up productivity'.[8]

Engevity identified Endeavour Energy as a similar network business to Western Power based on customer locations (albeit without a long rural category). Endeavour Energy was not used to inform Synergies selection of proposed value for annual productivity improvement. It has achieved an annual productivity growth of 7 per cent per annum from 2016 to 2020, and 2 per cent per annum over 2006 to 2020.

Engevity also considered there may be scope for Western Power to achieve greater operating expenditure efficiencies than it had included in its base operating expenditure as it had not identified "capex/opex trade-offs" in its base operating expenditure forecast from the transformation programs it is undertaking.

Engevity considers, on balance, that Western Power should be able to target an efficiency improvement across the AA5 period of 2 per cent per annum. This outcome is more consistent with Western Power's stated approach to estimating the productivity growth factor – using the most recent benchmarking data available and distinguishing between movements in the efficiency frontier versus 'catch up'.

Taking account of the analysis provided by the technical consultant, the ERA considers it is reasonable to expect a service provider efficiently minimising costs would seek to achieve a productivity factor of two per cent per annum. This requires Western Power to deliver operating expenditure efficiencies more consistent with other network operators in Australia.

Required Amendment 7

Amend the productivity factor to two per cent per annum.

5.2.5 Indirect Costs

Indirect costs are costs that are not directly linked to the networks program but are incurred as a result of the works program. They cover project management and coordination, as well as maintaining computers and facilities for operational staff. These indirect costs are allocated to activities and expensed or capitalised in line with Western Power's cost and revenue allocation model.

Western Power's proposed indirect expenditure for AA5 is set out in Table 7 below.

[8] AER, Forecasting productivity growth for electricity distributors, Final decision, March 2019, p. 8.

Table 7: AA5 proposed indirect expenditure (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Recurrent network base	151.8	151.8	151.8	151.8	151.8	758.9
Step changes	13.6	13.6	13.6	13.6	13.6	68.2
Total recurrent indirect costs	165.4	165.4	165.4	165.4	165.4	827.1
Network growth escalation	0.5	0.7	1.0	1.4	1.7	5.2
Productivity	(0.4)	(0.8)	(1.2)	(1.7)	(2.1)	(6.2)
Non-recurrent costs	0.0	0.0	0.0	0.0	0.0	0.0
Labour cost escalation	1.7	2.5	3.3	4.1	4.9	16.5
Total	167.2	167.8	168.5	169.2	169.9	842.6

Source: Western Power data

The recurrent network base costs are based on actual indirect costs (excluding those attributable to non-revenue cap expenditure) incurred in 2020/21.

The proposed step changes are for:

- Increased support services to support the capital program of $6.3 million each year.
- Increased IT contract support costs of $3.8 million each year.
- Cyber security program costs of $3.5 million each year.

The ERA considers the proposed step changes are reasonable to support the changes needed to manage the transformation programs.

Western Power has applied network growth to indirect costs. However, similar to corporate costs, the ERA considers indirect costs such as project management and coordination, and maintaining computes and facilities for operational staff, are not proportional to growth in service outputs that may result from changes in customer demand. Consequently, no growth escalation factors should be applied to indirect costs.

Consistent with its proposed operating expenditure, Western Power has included a 0.25 per cent per annum productivity improvement negative adjustment in its proposed indirect costs. As discussed under operating expenditure, the ERA considers a productivity factor of two per cent is reasonable.

For the reasons above, the ERA does not consider Western Power's proposed indirect expenditure is consistent with a service provider efficiently minimising costs and requires it to be amended as set out in Table 8 below.

Table 8: Draft decision indirect expenditure (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Recurrent Network Base	151.8	151.8	151.8	151.8	151.8	758.9

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Step changes	13.6	13.6	13.6	13.6	13.6	68.2
Total recurrent network costs	165.4	165.4	165.4	165.4	165.4	827.1
Network growth escalation	0.0	0.0	0.0	0.0	0.0	0.0
Productivity factor	(3.3)	(6.6)	(9.7)	(12.8)	(15.9)	(48.3)
Non-recurrent costs	0.0	0.0	0.0	0.0	0.0	0.0
Total[9]	162.1	158.9	155.7	152.6	149.6	778.8

Source: ERA analysis

The ERA's estimate of the allocation of indirect expenditure, after taking account of the adjustments to operating and capital expenditure set out in the draft decision, is shown in Table 9 below.

Table 9: Draft decision indirect expenditure allocation (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Total	162.1	158.9	155.7	152.6	149.6	778.8
Capitalised	125.9	122.7	121.5	117.7	113.9	601.7
Expensed	36.2	36.2	34.2	34.9	35.7	177.1

Source: ERA analysis

Required Amendment 8

Forecast indirect expenditure must be amended to be consistent with the ERA's draft decision including:

- Removing growth escalation.
- Amending the productivity factor to 2 per cent..

5.2.6 Labour cost escalation

Western Power has included labour cost escalation of 0.77 per cent for each year of AA5. Western Power engaged Synergies to provide a forecast of the annual rate of growth in the wage price index for Western Australian electricity, gas, water and waste water services.[10]

Western Power states it has applied the AER benchmark methodology to determine the proportion of labour costs of a benchmark efficient business rather than using its actual proportion of labour costs.

9 Before labour escalation.

10 A copy of Synergies report can be found here.

The ERA considers including a labour cost escalation factor is consistent with ensuring operating expenditure only includes those costs that would be incurred by a service provider efficiently minimising costs, providing the escalation factor is based on a reasonable forecast and is no higher than the assumed rate of productivity growth.

Western Power's forecasts are out of date. However, as the labour costs escalation is a relatively small component of Western Power's proposed costs the ERA has not amended the labour escalation component for the purposes of the draft decision. The ERA requires Western Power to update its forecasts to reflect current data and will review the forecast in the final decision, including ensuring that it is no higher than the assumed rate of productivity growth.

Required Amendment 9

The labour escalation factor must be updated to reflect the latest forecast data and must be no higher than the forecast rate of productivity growth included in forecast operating costs.

5.3 Total operating expenditure

Taking into account the consideration of the individual cost line items set out above, network growth escalation, labour cost escalation and other adjustments, the ERA considers that Western Power's forecast of operating expenditure is not consistent with the requirements of section 6.40.

The ERA's amended operating expenditure forecasts are set out in Table 10 below.

Table 10: Draft decision operating expenditure (real $ million at June 2022)

	2022/23	2023/24	2024/25	2025/26	2026/27	AA5 Total
Recurrent network base costs	348.1	348.1	348.1	348.1	348.1	1,740.5
Step changes	16.6	15.9	15.6	15.4	15.1	78.6
Total recurrent network costs	364.7	364.0	363.7	363.5	363.1	1,819.0
Network growth escalation	3.2	4.5	6.6	8.2	9.9	32.3
Productivity	(7.4)	(14.6)	(21.8)	(28.9)	(35.8)	(108.4)
Non-recurrent costs	10.9	18.1	13.4	13.2	16.9	72.5
Expensed Indirect costs	36.2	36.2	34.2	34.9	35.7	177.1
Labour cost escalation	4.2	6.2	7.9	9.7	11.5	39.4
Total	411.7	414.4	403.9	400.6	401.3	2,032.0

Source: ERA analysis

Required Amendment 10

Forecast operating expenditure must be amended to be consistent with the ERA's draft decision.

Appendix 1 Extract of relevant provisions from Access Code

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

6.41 Where, in order to maximise the net benefit after considering alternative options, a service provider pursues an alternative option in order to provide covered services, the non-capital costs component of approved total costs for a covered network may include non-capital costs incurred in relation to the alternative option ("alternative option non-capital costs") if:

(a) the alternative option non-capital costs do not exceed the amount of alternative option non-capital costs that would be incurred by a service provider efficiently minimising cost; and

(b) at least one of the following conditions is satisfied:

(i) the additional revenue for the alternative option is expected to at least recover the alternative option non-capital costs; or

(ii) the alternative option provides a net benefit in the covered network over a reasonable period of time that justifies higher reference tariffs; or

(iii) the alternative option is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

6.42 For the purposes of section 6.41(b)(i) "additional revenue" for an alternative option means:

(a) the present value (calculated at the rate of return over a reasonable period) of the increased tariff income reasonably anticipated to arise from the increased sale of covered services on the network to one or more users (where "increased sale of covered services" means sale of covered services which would not have occurred had the alternative option not been undertaken); minus

(b) the present value (calculated at the rate of return over the same period) of the best reasonable forecast of the increase in non-capital costs (other than alternative option non-capital costs) directly attributable to the increased sale of the covered services (being the covered services referred to in the expression "increased sale of covered services" in section 6.42(a)),

where the "rate of return" is a rate of return determined by the Authority in accordance with the Code objective and in a manner consistent with this Chapter 6, which may be the rate of return most recently approved by the Authority for use in the price control for the covered network under this Chapter 6.

"**efficiently minimising costs**" in relation to a *service provider*, means the *service provider* incurring no more costs than would be incurred by a prudent *service provider*, acting efficiently in accordance with *good electricity industry practice* seeking to achieve the lowest sustainable cost of delivering *covered services* and without reducing *service standards* below the *service standard benchmarks* set for each *covered service* in the *access arrangement* or *contract for services*.

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

"**alternative options**" means alternatives to part or all of a *major augmentation* or *new facilities investment*, including *stand-alone power systems, storage works*, demand-side management and *generation* solutions (such as distributed *generation*), either instead of or in combination with *network augmentation*.