31 January 2023

Attachment 6.1: Proposed operating expenditure

Ausgrid's 2024-29 Regulatory Proposal

Empowering communities for a resilient, affordable and net-zero future.

Ausgrid

Contents

1. Executive summary

Operating expenditure (**opex**) includes the costs of operating and maintaining our physical assets (such as our poles, wires, substations and monitoring and control systems), responding to emergencies (such as fallen trees on our power lines) and undertaking customer-related functions (such as providing call centre services). In general, opex reflects our activities and costs that are recurrent.

In developing our opex forecast for the 2024-29 period, we sought to estimate the efficient and prudent costs to operate and maintain our network over this period to a standard that ensures our customers continue to have access to a safe and reliable electricity supply, and complies with our regulatory obligations and requirements. We also sought to meet the Australian Energy Regulator's (**AER**) expectations on opex forecasts set out in its Better Resets Handbook, including applying the base-step-trend methodology.

Figure 1.1 summarises our assessment of how our opex forecast meets these expectations.

Figure 1.1 How our opex forecast meets the AER's expectations

Expectation		Our assessment
Forecasting approach	Base-step-trend method	✓
	Base year	✓
	Trend	✓
	Step changes	✓
	Category specific forecasts	✓
Genuine consumer engagement	Impact on service level outcomes	✓
	Consistency with consumer preferences	✓
	Deviation from base-step-trend	✓

We are confident our forecast opex is prudent and efficient and achieves the operating expenditure objectives set out in the National Electricity Rules (**NER**). We outline how we consider our opex forecast achieves these objectives at **Section 8** below.

In particular, we note, in real $ FY24[1]:

- Our forecast opex is 14% lower than our current period allowance;
- Excluding the impact of the changed accounting treatment of Software as a Service (**SaaS**) IT solutions,[2] our forecast opex is 2% higher than current period actual opex; and
- There is a $35 million productivity saving which is fully passed through to customers.

Over the current 2019-24 period, we have undergone significant transformation and reduced opex by 30%,[3] which will be passed through to customers through lower costs in the forthcoming regulatory period. We have achieved significant cost reductions by reducing in the number of full-time equivalent employees, and the implementation of

[1] All dollar values in this document are in real $, FY24 unless otherwise stated.
[2] In April 2021, the International Financial Reporting Interpretations Committee (**IFRIC**) decided the costs associated with configuring and customising SaaS IT solutions must be treated as opex, rather than capex as previously was the case. We have included these costs in our forecast opex as a base year adjustment.
[3] Real FY24 reduction between FY19 and FY23.

non-labour transformation initiatives – including information, communications and technology (**ICT**) licence cost reductions, savings in vegetation management and reductions in fleet costs.

Our Regulatory Proposal has been informed by an extensive and rigorous customer engagement program. Throughout this engagement, our customers and stakeholders have consistently told us that:

- Energy costs are difficult to manage, so energy needs to be affordable; and
- We should invest to reduce long term costs.

Our forecast opex recognises our customers' concerns regarding affordability, as well as the desire to reduce costs in the future. We are proposing to:

- Build on the significant cost reductions implemented since 2015;
- Unlock efficiencies by investing in system and process improvement (e.g. SAP implementation, as discussed in **Attachment 5.1 – Proposed capital expenditure**); and
- Invest in smart meter data and real-time smart meter functionality to enable more efficient growth capital expenditure (**capex**), lower opex, and enhance safety benefits and outcomes for customer energy resources (**CER**) customers.

Throughout our engagement, our customers and delivery partners consistently told us they want Ausgrid to do more than continue to deliver safe, reliable, and affordable energy services over the 2024-29 period and beyond. While meeting these core expectations remains essential, we have learned that our customers and delivery partners also expect us to support the transition to a cleaner, more sustainable energy system and to help them realise their own net zero ambitions and empower them to manage their own energy costs. Our communities' top priorities and how we have responded to these in our proposal are summarised in **Figure 1.2**.

Figure 1.2 How we have taken customer and stakeholder feedback on board in developing this proposal

Customer feedback	How we have responded
Facilitating an affordable energy transition	Our proposed opex forecast reflects our continued focus on efficiency. We have proposed a productivity adjustment of 0.5% per annum to our opex forecast, and also included a 0.5% productivity factor to capitalised overheads to reflect that productivity gains made in overheads would also flow to capex. In response to feedback from the Reset Customer Panel (**RCP**) we did not proceed with some step changes and are absorbing some cost increases.[4]
Building the resilience of our network to reduce climate and cyber risks	We have included two step changes in our opex forecast to improve the resilience of our network and communities to climate change and to reduce cyber security risks.
Delivering net zero	We have included two step changes that will help us facilitate the transition to net zero through: • The Network Innovation Program (**NIP**) – which comprises a range of trials and pilots covering leading edge energy technologies to support the rapidly evolving electricity sector; and • Upgrading ICT systems to efficiently enable CER integration.

In developing our opex forecast for the 2024-29 period, we have:

[4] For our 2024-29 regulatory proposal, we also engaged with the RCP, our independent challenge panel, and a dedicated regulatory reset Voice of Community Panel. See **Chapter 3** of our **2024-29 Regulatory Proposal** or **Attachment 3.1 – Engagement overview** for more information.

- Considered direct feedback from customers and stakeholders from our Voice of Community (**VoC**) engagement program and ongoing engagement with the RCP;
- Published our 2024-29 Draft Plan in September 2022, and responded to the feedback received from customers and stakeholders on that Draft Plan;
- Considered our historical and current performance and benchmarking outcomes;
- Considered the circumstances we are expected to face in the 2024-29 period; and
- Applied the AER's base-step-trend methodology and other requirements of the AER's Expenditure Forecast Assessment Guideline.

Our forecast opex for the next regulatory period is $2,375 million excluding debt raising costs and $2,420 million including debt raising costs (real $, FY24). The annual forecast is shown in **Figure 1.3**.

Figure 1.3 Forecast opex, 2024-29, (real $m, FY24)

Opex	FY25	FY26	FY27	FY28	FY29	Total
Opex excluding debt raising costs	463.6	472.1	475.8	479.9	483.7	2,375.0
Debt raising costs	9.0	9.1	9.1	9.1	9.1	45.4
Total opex	**472.6**	**481.2**	**484.9**	**489.0**	**492.8**	**2,420.5**

Noting the above, and as detailed in this attachment, our opex forecast represents the expenditure we consider reasonably reflects:

- The efficient costs of achieving the opex objectives listed in clause 6.5.6(a) of the NER;
- The costs that a prudent operator would require to achieve the opex objectives; and
- A realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

NER clause 6.5.6(b)(2) provides that our proposed forecast opex must be for expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in the Cost Allocation Method (**CAM**) for the Distribution Network Service Provider. We confirm our forecast opex is for the provision of standard control services and represents expenditure that has been properly allocated to standard control services in accordance with the policies and principles set out in Ausgrid's CAM as approved by the AER on 26 October 2022.[5]

[5] The new CAM applies from 1 July 2024.

2. Our forecast opex

Opex includes the costs of operating and maintaining our physical assets (such as our poles, wires, substations and monitoring and control systems), responding to emergencies (such as fallen trees on our power lines), as well as undertaking customer-related functions (such as providing call centre services) and back-office functions. In general, opex reflects our activities and costs that are ongoing and recurrent.

In developing our opex forecast for 2024-29, we have sought to meet the AER's expectations on opex forecasts set out in its Better Resets Handbook, including applying the AER's preferred 'base-step-trend' methodology. **Figure 2.1** summarises how our opex forecast meets these expectations.

The sections below provide an overview of our opex forecast, then outline:

- Our opex forecast compared to our recent opex performance trend;
- How our opex forecast responds to customer and stakeholder priorities and preferences;
- Our opex forecasting method and how we applied its key steps; and
- How our opex forecast meets the opex objectives, criteria and factors in the NER.

Figure 2.1 How our opex forecast meets the AER's expectations

Expectation		Our assessment	Explanation	Where discussed
Forecasting approach	Base-step-trend method	✔	We have used the base-step-trend method	**Section 4**
Forecasting approach	Base year	✔	We have used the base year for which there will be audited actuals for the final decision	**Section 5**
Forecasting approach	Step changes	✔	We have met one or more of the AER's categories for step changes, including being supported by customers	**Section 6**
Forecasting approach	Trend	✔	We have aligned with the AER's standard methodology to estimate trend	**Section 7**
Forecasting approach	Category specific forecasts	✔	We have limited our category specific forecasts to categories previously agreed in AER decisions	**Section 6**
Genuine consumer engagement	Impact on service level outcomes	✔	We have not proposed any cost changes that would compromise our current level of service delivery	**Section 5**
Genuine consumer engagement	Consistency with consumer preferences	✔	We have consulted on cost increases and aligned with customer preferences	**Section 6**
Genuine consumer engagement	Deviation from base-step-trend discussed with customers	✔	Deviations from base-step-trend have been discussed with customers	**Section 4**

2.1 Overview

Our opex forecast for the 2024-29 period is $2,375 million (real $, FY24), excluding debt raising costs[6] (see **Figure 2.2**). This is 14% lower than our current period opex allowance, 10% higher than our current period forecast spend, and 5% higher than the opex we included in our Draft Plan. If the impact of the changed accounting treatment of SaaS ICT solutions[7] is excluded, our forecast is 2% higher than the current period spend.

Our opex forecast also includes an upfront $35 million (real $, FY24) productivity saving, which is fully passed through to customers.

Figure 2.2 Forecast opex by category, 2024-29 (real $m, FY24)

	2024/25	2025/26	2026/27	2027/28	2028/29	Total period
Vegetation management	41.2	41.5	41.6	41.9	42.2	208.4
Maintenance	45.5	45.9	46.0	46.3	46.6	230.4
Emergency response	29.0	29.2	29.3	29.5	29.7	146.7
Non-network	177.3	181.4	182.5	184.3	186.0	911.4
Network overheads	136.1	138.3	139.9	141.1	142.5	698.0
Corporate overheads	34.5	35.8	36.4	36.8	36.6	180.1
Subtotal	**463.6**	**472.1**	**475.8**	**479.9**	**483.7**	**2,375.0**
Debt raising costs	9.0	9.1	9.1	9.1	9.1	45.4
Total opex	**472.6**	**481.2**	**484.9**	**489.0**	**492.8**	**2,420.4**

2.1.1 We have transformed our business

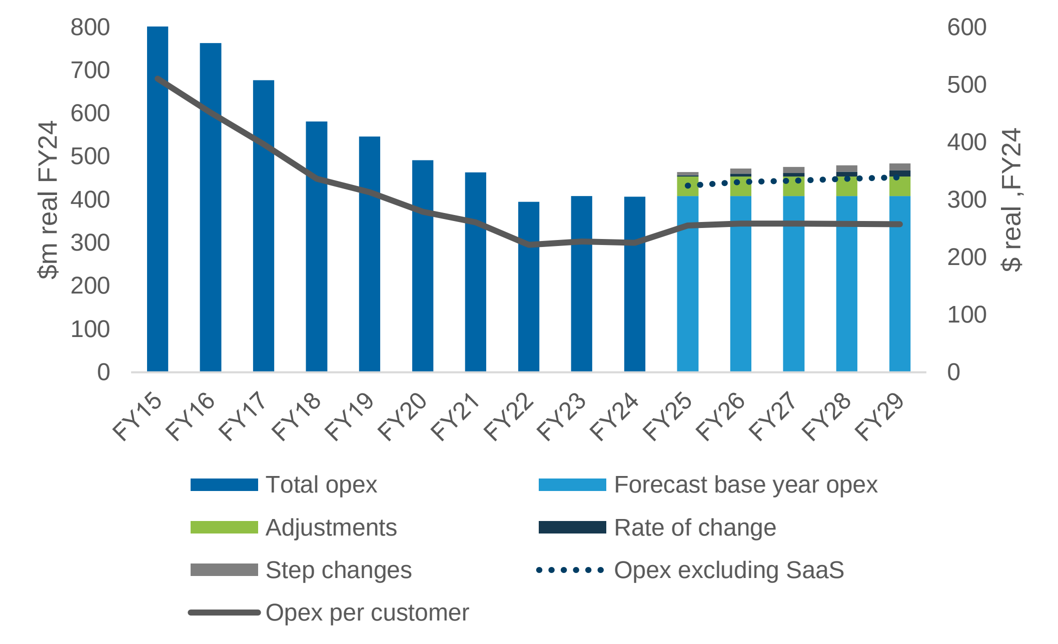
Over the 2019-24 period, we have undergone significant transformation which has reduced ongoing opex (see **Figure 2.3**) and is passed through to customers through lower costs in the next regulatory period. We have reduced our full time equivalent number of employees by 19% from 3,576 as at 30 June 2019 to 2,908 as at 30 June 2022. We have achieved other significant cost reductions through the implementation of non-labour transformation initiatives including ICT licence cost reductions, savings in vegetation management and reductions in fleet costs.

While we have achieved significant costs savings during the current regulatory period, our opex forecast for the 2024-29 period indicates that we expect our costs to increase compared to the current period. This is mainly due to:

- The change in accounting treatment for SaaS IT solutions (as outlined in **Section 5.3.3**);
- Step changes, as outlined in **Section 6;** and
- Changes to our CAM which allocate more indirect costs to standard control services compared to the current regulatory period (as outlined in **Section 5.3.1**).

[6] Debt raising costs are added to total opex to cover, for example, arrangement fees, credit rating fees, and issuer legal counsel fees associated with raising debt.
[7] In April 2021, the International Financial Reporting Interpretations Committee decided the costs associated with configuring and customising SaaS IT solutions must be treated as opex, rather than capex as previously was the case. We have included these costs in our forecast opex as a base year adjustment.

Figure 2.3 Forecast opex and opex per customer for the 2024-29 period compared to actual/estimated opex for 2019-24 and 2015-19 ($m, real FY24)



2.2 How our opex forecast responds to customer priorities

In our engagement to inform our 2024-29 Draft Plan, our customers and stakeholders told us that:

- Energy costs are difficult to manage, so energy needs to be affordable;
- We should invest to reduce our long-term costs;
- We should improve our climate and cyber resilience; and
- We should prioritise innovation that supports the energy transition.

In our Draft Plan, we outlined potential responses to the feedback we had received from customers in developing our plans for the 2024-29 period. The responses indicated we should:

- Invest in smart-meter data and real-time smart meter functionality that will lead to more efficient growth capex, lower opex, and enhance safety benefits and outcomes for CER customers;
- Improve our communities' climate resilience, for example, by employing new staff to run outreach programs, provide information about climate resilience and support communities during prolonged outages caused by extreme weather events;
- Invest in a cyber security program that would enable us to adopt practices and protections in line with industry best practice (Security Profile 3 of the Australian Energy Cyber Security Framework); and
- Add an opex component to our current Network Innovation Program to allow us to select the most efficient energy technology options for customers, and conduct ongoing research on community attitudes, expectations and preferences on issues relevant to this program, as well as contribute to long-term capex savings.

We included step changes in the Draft Plan to address this feedback, sought comment on them and tested them further with the RCP (particularly the ICT enablement program for CER integration). In response to this feedback, and further development of forecasts, we made some minor adjustments to our proposed opex, as shown in **Figure 2.4**. Further details on each component of opex outlined below is in **Section 6**.

Figure 2.4 How we have taken customer and stakeholder feedback on board in developing our step changes

$m real FY24	Draft Plan	Regulatory Proposal	Difference	Reason for change
Insurance premiums	27.8	9.5	(18.3)	Adjusted based on more recent information, including updated forecasts by Marsh, changes to inflation forecasts and changes to the baseline adopted to forecast the step change (see **Section 6.2** and **Attachment 6.3 Marsh Insurance Report**)
Community resilience	25.0	8.4	(16.6)	Updated analysis, feedback from Voice of Community Panel and emergency response costs moved into base year adjustments (see **Section 6.3**)
Cyber security	18.3	20.6	2.3	Update reflects more recent inflation information (see **Section 6.4**)
Smart meter data	23.5	24.9	1.4	Update reflects more recent inflation information (see **Section 6.5**)
Network Innovation Program	5.0	5.0	No change	No change despite strong support by Voice of Community Panel to increase (see **Section 6.6**)
ICT enablement for CER integration	N/A	10.4	10.4	New step change that evolved as CER analysis progressed (included within $114m CER totex (see **Section 6.7**))
Property step change	N/A	(14.5)	(14.5)	Reduced land tax and other costs associated with property sales (see **Section 6.8**)

3. Historical performance

For the current period, the AER approved an efficient operating expenditure allowance of $2,299 million (real, FY19 excluding debt raising costs) or $2,764 million (real, FY24). Over the current regulatory period we expect to incur $2,155 million of operating expenditure, which is $609 million less than the current period efficient allowance. As noted in **Section 2.1.1**, this lower spend is due to significant transformation activities. **Figure 3.1** presents our opex for each year of the previous and current regulatory periods, as well as the 2024-29 period.[8]

Figure 3.1 Total opex by category for the 2014-19 and 2019-24 periods excluding debt raising costs ($m, real FY24)

	Previous regulatory period					Current regulatory period					Next regulatory period				
	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29
Vegetation management	52	43	63	60	49	50	48	41	40	41	41	42	42	42	42
Maintenance	91	74	60	45	37	41	37	39	46	45	46	46	46	46	47
Emergency response	82	42	37	28	31	56	37	32	23	26	29	29	29	29	30
Non-network	214	154	156	157	146	142	146	139	142	145	177	181	182	184	186
Network overheads	265	244	169	151	135	141	105	117	125	122	136	138	140	141	143
Corporate overheads	142	193	181	132	143	51	83	30	32	32	35	36	36	37	37
Total	**846**	**750**	**666**	**573**	**541**	**481**	**455**	**398**	**409**	**411**	**464**	**472**	**476**	**480**	**484**

3.1 Comparison of our historical and forecast opex

Our opex has decreased significantly over the previous and current regulatory periods. The transformation of our business has resulted in expenditure decreases across all categories but most notably in network and corporate overheads.

Our forecast for the 2024-29 period is 10% higher than the current period, however this reduces to 2% excluding the impact of the changed accounting treatment of SaaS ICT solutions. This change does not increase our overall forecast totex for ICT, it moves cost from capex to opex. This accounts for $155 million of the increase between the current and next period opex (see **Section 5.3.3**) and can be seen in the increase in the non-network category between FY24 and FY25 in **Figure 3.1** above. The non-network category is also affected by the cyber security step change (see **Section 6.4**), the ICT enablement program for CER integration step change (see **Section 6.7**) and the property negative step change (see **Section 6.8**).

Other forecast increases between FY24 and FY25 in **Figure 3.1** are due to:

- The base year adjustment for emergency response (see **Section 5.3.2**);
- Step changes for community resilience, smart meter data and network innovation which affect network overheads (see **Sections 6.3**, **6.5** and **6.6**, respectively);
- The updated CAM which affects network and corporate overheads (see **Sections 5.3.1**); and
- The step change for insurance premiums which affects corporate overheads (see **Section 6.2**).

[8] Presented in well-accepted categories as required by NER clause S6.1.2(1).

4. Forecasting method

As part of our Regulatory Proposal, the NER requires us to:

- Submit an Expenditure Forecasting Methodology;
- Describe the method used for developing the opex forecast;
- Include forecasts of key variables relied upon to derive the opex forecast and the method used for developing those forecasts; and
- Provide the key assumptions that underlie the opex forecast.[9]

We submitted our Expenditure Forecasting Methodology in June 2022.[10] We outline the other information in this section. Our forecast opex model is provided at **Attachment 6.1.a - Opex Model**.

4.1 Forecasting methodology for opex

We have applied the AER's preferred base-step-trend forecasting methodology to develop our opex forecast for most costs.[11] For the remaining costs (such as debt raising costs and the costs associated with step changes or base year adjustments), we have used a specific forecasting approach, which better reflects the nature of these costs.

Figure 4.1 below summarises how we have applied the base-step-trend methodology in developing our forecast opex. This method ensures that forecast opex reasonably reflects a realistic expectation of the cost inputs and demand forecasts for the next regulatory period.

[9] NER, clauses, S6.1.2(2), (3) and (5).
[10] Ausgrid (2022) Expenditure Forecasting Methodology.
[11] See AER (2013), Expenditure Forecast Assessment Guideline for Electricity Distribution, p 22.

Figure 4.1 Base-step-trend forecasting methodology

Start with the efficient base year

We selected actual opex in FY23 as the proposed base year as the most recent year of actual financials by the time of our final decision. We consider that this is representative of the efficient annual costs needed to operate and maintain the network.

▼

Adjust the base year

We adjusted the base year for any non-recurrent costs (if there are any) which are not reflective of ongoing opex requirements. We also adjusted the base year for other changes that affect our future opex.

▼

Trend the base year forward

We trended base year opex forward by taking into account expected growth in input prices, such as labour (0.6% per year on average), output (0.5% per year on average) and productivity gains (0.5% per year).

▼

Adjust for step changes (positive or negative)

We adjusted the efficient base year to account for identified step changes, which reflect changes in costs relating to a change in regulatory requirements, or other external factors outside of management control, or where there is an efficient trade-off between opex and capex.

▼

Add category specific forecasts

We added debt-raising costs (around $9 million per year) using a specific forecasting approach, which better reflects the nature of these costs

▼

Forecast opex for the 2024-29 period

While we have used the base-step-trend approach for most opex, there are exceptions where a specific approach has been used. A specific approach has been used to forecast the following:

- Base year adjustments – we have applied five year average costs to forecast these costs;
- Step changes – step changes require a specific approach because trending forward the revealed cost does not produce a forecast of future efficient costs required to meet the opex objectives; and
- Debt raising costs – Ausgrid has adopted the method that the AER uses to derive debt raising costs which is to apply a benchmark debt raising unit rate of 0.081% (placeholder based on previous determination) to the debt portion of our Regulated Asset Base (**RAB**).

Figure 4.2 below summarises our opex categories and identifies which forecasting method we have used for each category.

Figure 4.2 Forecast method by opex category

Base-step-trend forecasting approach

Network maintenance

- Inspection
- Corrective maintenance
- Breakdown maintenance
- Nature-induced maintenance
- Non-direct maintenance
- Engineering support

Operating and business support

- ICT
- Property management
- Network operations
- Training and development
- Finance costs
- Other operations and business support costs

Bottom-up or specific approach

Other costs

- Base year adjustments
- Step changes
- Operating expenditures relating to debt raising costs

4.2 Key variables and assumptions

NER clause S6.1.2(3) requires us to include forecasts of key variables relied on to derive the opex forecast and the method used for developing those forecasts. The key variables used in the opex forecast relate to our proposed trend adjustments for opex, and comprise:

- Real cost escalation;
- Output growth; and
- Productivity growth.

The forecasts of these key variables and the methods for developing them are discussed in **Section 7**.

NER clauses S6.1.2(5) and (6) requires Ausgrid to provide details of the key assumptions underpinning our forecast opex and a directors' certification as to the reasonableness of those key assumptions. **Attachment 2.2 – Key assumptions and Directors' certification of key assumptions** details of our key assumptions and provides the directors' certification. The table below outlines our key assumptions relevant to the opex forecast.

Figure 4.3 Key assumptions – forecast opex

Key assumptions	Description
Regulatory obligations	Our forecast operating expenditure for the 2024-29 regulatory period is based on current legislative and regulatory obligations. It is assumed that – except where specified – there are no new substantive regulatory obligations and/or major change in scope of current regulatory obligations over the 2024-29 period
Base year opex	Ausgrid's forecasting approach assumes that the amount of opex required to meet the opex objectives over the 2024-29 period will broadly reflect current opex requirements, with adjustments to reflect changes in input costs, outputs delivered, productivity and step changes.

5. Base year

The purpose of the base year in the base-step-trend approach is to provide a reasonable starting point for our prudent and efficient opex forecast. Our base year shows what we currently incur for recurrent activities and reflects our on-going requirements to maintain the quality, safety and reliability of our network during the next regulatory period, consistent with our customers' expectations.

Our task is to determine a reasonable approximation of base opex for the last year of the current period, being FY24, which will not be known at the time of the AER's final decision. To ensure the base-step-trend forecasting approach produces a prudent and efficient forecast, an efficient level of base year opex must be selected.

5.1 Selection of base year

We have nominated FY23 as the base year for forecasting opex because:

- It is the most recent regulatory year for which audited regulatory accounts and other financial information will be available when the AER makes its final decision in April 2024;
- We consider it best represents our underlying operating conditions in the current 2019-24 period, and the conditions we expect for the 2024-29 period. To date, it has not included unusual events or factors that indicate it will not be reflective of our normal operating environment; and
- While we do not yet know our actual opex in FY23, our base year estimate is our latest forecast.

We achieved significant savings during the current regulatory period from transformation activities. While we expect to continue improving and making further savings, the scale achieved in the current period is not expected to continue into the next regulatory period.

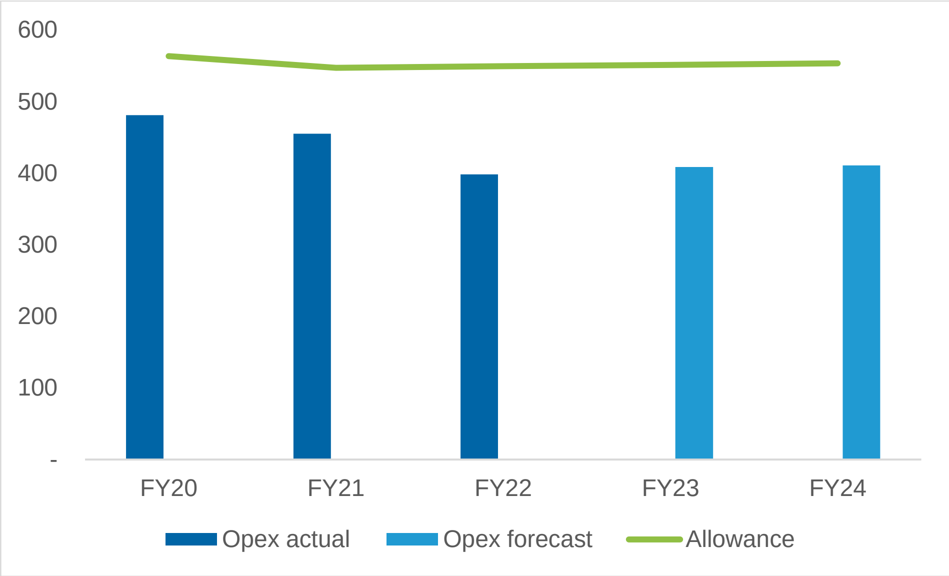
The AER indicates in the Better Resets Handbook that it prefers a base year for which audited actual opex is available.[12] While we have used our FY23 forecast, we will update the FY23 forecast with actual spend for FY23 in our 2024-29 Revised Proposal. Audited actuals will be available for FY23 at the time of our revised proposal and the AER's final decision, therefore we believe this meets the Better Reset Handbook criteria.

We also note the operation of the efficiency benefit sharing scheme (**EBSS**) ensures that our revenue is unaffected by the choice of base year. As we have used the base-step-trend forecasting approach, our opex forecast is consistent with the operation of the EBSS in the 2019-24 period and its proposed operation in the 2024-29 period.

Figure 5.1 compares our proposed base year opex to our operating expenditure incurred in FY20-22, estimates for FY23 and FY24 and the AER's allowance for the current period. This comparison supports our view that FY23 is suitable to use as the base year for our opex forecasts for the 2024-29 period for the reasons provided above.

[12] AER (2021), *Better Resets Handbook – Towards consumer centric network proposals*, p 25.

Figure 5.1 Comparison of base year opex to other years excluding debt raising costs ($m, real FY24)



5.2 Efficiency of the base year

5.2.1 Benchmarking of Ausgrid's operating expenditure base year

Benchmarking is a useful tool we can use to assess whether our costs are aligned with our peers who deliver the same services. In some cases, costs will be different for valid reasons, however overall we would expect some level of comparability. There are a range of benchmarking tools used by the AER which can be found in the annual benchmarking reports published on the AER website.

We support the AER's approach to taking a holistic assessment of benchmarking evidence in determining a distribution network service provider's (**DNSP**) efficiency, considering a broad range of evidence including Multilateral Total Factor Productivity (**MTFP**), Multilateral Partial Factor Productivity (**MPFP**), Partial Performance Indicators (**PPI**) and econometric models.[13] We believe this approach better accounts for differences in circumstances between DNSPs, and provides a better overall view of our relative performance, especially given some of the factors outlined in the following section that have influenced our results.

We note however, the limitations of some of the benchmarking techniques, as noted in our submission to the AER's draft 2021 Benchmarking Report.[14] Timing is critical with respect to the performance of the opex econometric models, in particular the Translog models. The problems encountered with the Translog models mean that results are reported differently for the long period (four models, except for CitiPower, Jemena Electricity Network (**JEN**) and United Energy) and the short period (two models). Each year, depending on the monotonicity violations, models could be included or excluded for the purpose of determining efficiency for a particular business. We are concerned that there could be different outcomes regarding efficient opex depending on the stability of an econometric model, which has no actual bearing on the efficiency or otherwise of a business in comparison to other businesses.

We note the AER's proposed development work program to improve the benchmarking methodology based on feedback from stakeholders, including:

- Reviewing the impact of differences in cost allocation and capitalisation approaches;
- An independent review of the non-reliability output weights used in the TFP and MTFP benchmarking;

[13] For example, in the AER's recent decisions for Evoenergy and Ergon Energy, the AER considered a range of benchmarking measures, including its econometric models and PPI measures to assess the DNSPs' proposed base year opex. See, AER, Evoenergy 2019-24 - Draft decision - Attachment 6 - Operating expenditure, September 2018, p. 23-26 and AER, Final decision - Evoenergy distribution determination 2019-24 - Attachment 6 - Operating expenditure, April 2019, p. 12 and AER, Final decision – Ergon Energy distribution determination 2020-25 – Attachment 6 Operating expenditure, June 2020, p. 15-21.

[14] Ausgrid (2021), *Ausgrid submission to 2021 AER draft distribution benchmarking report*.

- Improving the performance of the opex econometric cost function models, and the reliability of the Translog models; and
- Reviewing model specifications accounting for CER.

As noted in our submission to the AER's draft 2021 Benchmarking Report, we welcome the program of work identified by the AER to continue to improve the benchmarking methodology. We also noted that an overall 'health check' is timely given identified errors or issues with some of the models.[15]

In the absence of a single review of the benchmarking methodology, the timing of the various reviews and their potential impact on our regulatory determination process are of concern to Ausgrid. It is not clear whether the outcomes of the reviews will be available to apply to Ausgrid's 2024-29 regulatory determination. We note that the AER took a pragmatic approach in assessing JEN's opex in their recent determination and applied an operating environment factor (**OEF**) to account for capitalisation differences. We consider that the AER should adopt a similar approach for this determination where it is clear that an issue needs addressing, but the review has not started/completed, for example accounting for CER integration in model specification.

Benchmarking our base year

Our benchmarking analysis is based on the AER's 2022 Annual Benchmarking Report.[16] Our historical opex compares poorly to other businesses based on this analysis. However, because of our efforts to reduce opex in the current and previous regulatory periods Ausgrid has become the most improved in the AER's opex MPFP in recent years. This improvement has contributed to our proposed base year opex meeting the AER's benchmark of not being materially different to the 0.75 comparison point.

Our performance varies across the AER's productivity index numbers, econometric modelling and partial performance indicators. A number of factors affect these benchmarking results, including that:

- Some techniques used in the report, including the econometric models, estimate an average result over the period 2006-20 and 2012-20. It will be some time before our performance improves under these approaches, as the analysis includes historical cost levels that are no longer reflective of our cost base;
- Some models do not include adjustments for OEFs (circumstances or features that may be unique to particular DNSPs and impact relative opex); and
- The cost category PPI outcomes are dependent on the output that the category level opex is compared against. While the AER does consider a range of output measures, the choice of output measure can result in significantly different results, as shown in **Figure 5.2** below.

Figure 5.2 Cost category PPI outcome rankings

Benchmark	2017-21 average rank
Maintenance opex per customer	2
Maintenance opex per km of circuit length	7
Vegetation management opex per customer	6
Vegetation management opex per km of overhead circuit length	13

Source: AER 2022 Annual Benchmarking Report

Opex MPFP performance

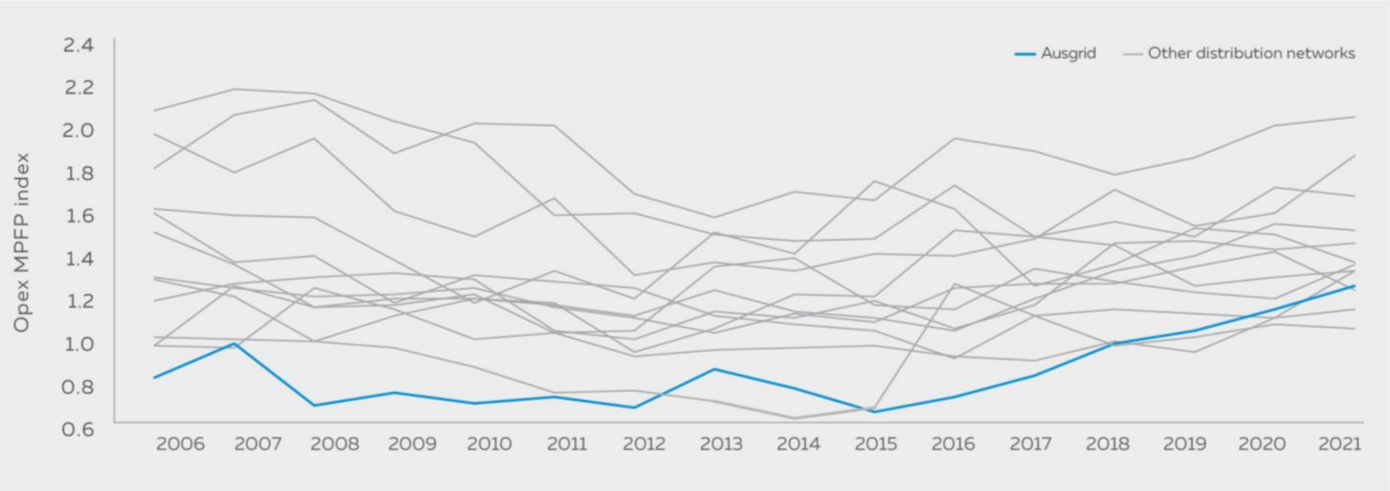
We have considered our performance against the other DNSPs using Quantonomics' opex MPFP model, which attempts to account for relative productivity levels across DNSPs (as well as the trends over time). As can be seen in **Figure 5.3** below, our relative performance has continued to improve over the current regulatory period. In particular:

[15] Ausgrid (2021), *Ausgrid submission to 2021 AER draft distribution benchmarking report*.
[16] AER (2022), *Annual benchmarking report – distribution network service providers*.

- While we have been in the bottom 3 for opex MPFP between 2006 and 2018, we have shown significant improvement since 2015;
- Our MPFP performance improved by 9% in 2021, compared to prior years, and we have consistently been one of the most improved DNSPs since 2015; and
- In 2021 we improved our MPFP ranking to 10th placed ranking, and expect to continue to improve this ranking again based on our actual opex for 2022.

Based on the improvement in our relative efficiency, we believe that we are no longer materially inefficient compared to our peers.

Figure 5.3 Ausgrid opex MPFP continues to improve



Source: AER 2022 Annual Benchmarking Report

The AER has observed that productivity levels of DNSPs have started to converge over time. As a result, relative productivity of DNSPs is much closer.[17] This is because less efficient DNSPs have improved their performance since 2012, while the most productive DNSPs in the National Electricity Market (**NEM**) have experienced a gradual overall decline in productivity since 2006.

Our productivity has consistently improved since 2015 and has improved relative to other DNSPs. Improving efficiency remains a key focus for Ausgrid in the 2024-29 period.

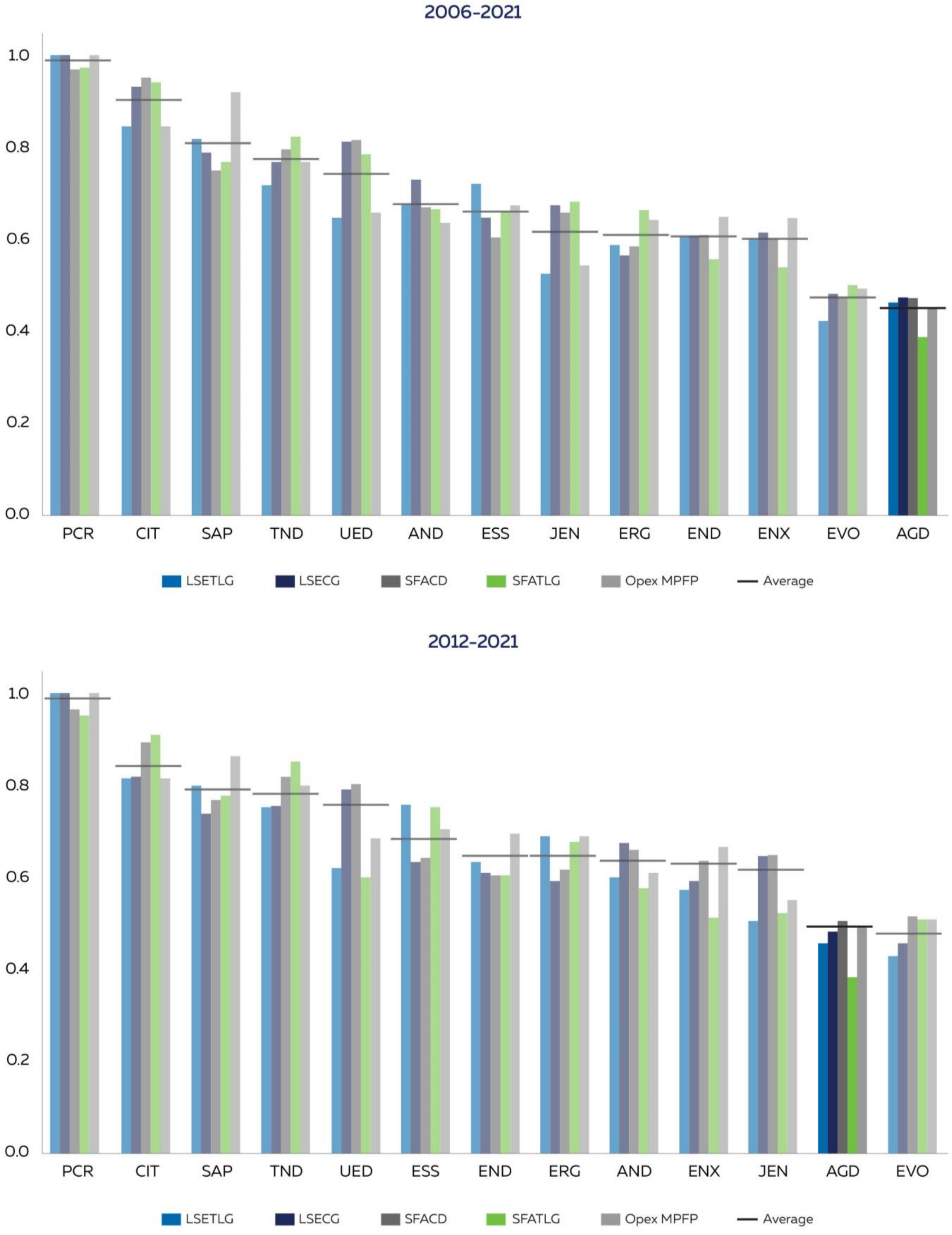
Econometric models

The AER's opex econometric models are the most critical of the AER's benchmarking techniques because they are used deterministically when assessing revealed costs, or substituting a DNSP's opex. **Figure 5.4** shows the results of econometric benchmarking – both for the 2006-2021 and 2012-2021 periods. These results are similar to the results of opex MPFP benchmarking (shown in **Figure 5.3** above).

Ausgrid performs better in the shorter period because as noted earlier, it takes some time for efficiencies to be reflected in the outcome. Our significant improvements in opex began in 2015, so the years prior to 2015 are still influencing the results. We recognise that Ausgrid's opex performance appears inefficient, however when considering other benchmarking tools and metrics, and the significant improvements since 2015, we consider our base year to be efficient.

[17] In 2005, the spread of opex MPFP between DNSPs was from around 0.8 to 2.0. In 2020, the spread is much closer, from 1.0 to 1.9.

Figure 5.4 DNSP opex efficiency scores – econometric models and MPFP



Source: AER 2022 Annual Benchmarking Report

Operating environment factors

OEFs are factors that can influence a DNSP's costs, but are outside of the DNSP's control. OEFs are applied to the estimate of efficient opex and may be positive (increases efficient opex) or negative (decreases efficient opex).

We note that we have some concerns with how the OEFs have been calculated by the AER and the data that has been used to calculate them, including that:

- The two new OEFs that relate to vegetation management (division of responsibility and bushfire risks) were developed through revenue determination processes for a small number of DNSPs, rather than through a broad industry consultation process. We note that data was collected from a limited number of businesses to calculate this OEF, so it may be incomplete;
- The division of responsibility OEF is calculated differently to the way other OEFs are calculated (to calculate the amount by which the reference point for Ausgrid would need to be lowered in order to allow a like-for-like comparison between Ausgrid and the reference DNSPs). In contrast, the division of responsibility OEF considers how Ausgrid's opex may reduce if it were to operate in an environment similar to that of the average reference firm. This difference in the way the AER computes and applies all other OEFs can result in materially different OEF adjustments; and
- The data for other OEFs has not been updated since the original analysis, though there may have been a material change in costs between businesses since that time. We continue to advocate for a holistic review of OEFs, given some data used to calculate the OEFs is outdated – rather than the AER continuing to refine OEFs on an ad-hoc basis.

Despite these concerns we have used the AER's OEF model to estimate the OEFs as they apply to Ausgrid. This results in a negative adjustment of 7.1% for the long period and 7.6% for the short period.

Partial performance indicators

The AER also considers PPI measures to support their benchmarking analysis and compare the results to the MTFP, MPFP and econometric analyses to provide a holistic view of DNSPs' efficiency. As part of how we measure ourselves against other NEM DNSPs we compared how our performance against these PPI measures has changed over time. We used average PPI data over the following 2 regulatory periods to assess the improvement across the PPI measures as the percentage change between:

- 2016-20 (presented in the 2021 annual benchmarking report); and
- 2017-21 (presented in the 2022 annual benchmarking report).

This analysis shows that Ausgrid was one of the strongest performers, if not the strongest performer, in terms of improvement in the average ratio for most of the PPIs considered by the AER (see **Figures 5.5** to **5.10**).

Figure 5.5 Percentage change in total cost per customer PPI

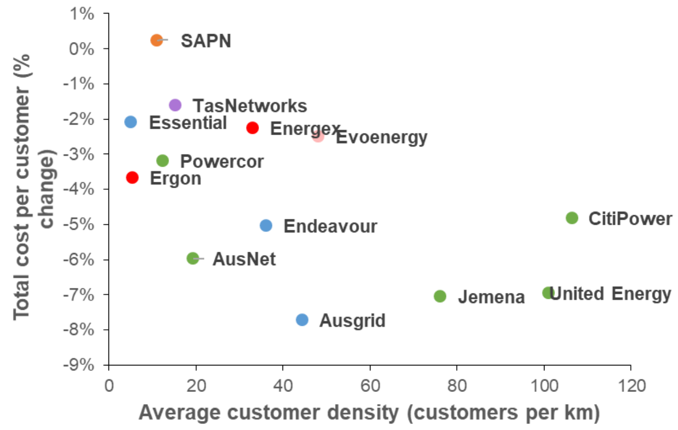


Figure 5.6 Percentage change in total cost per circuit length PPI

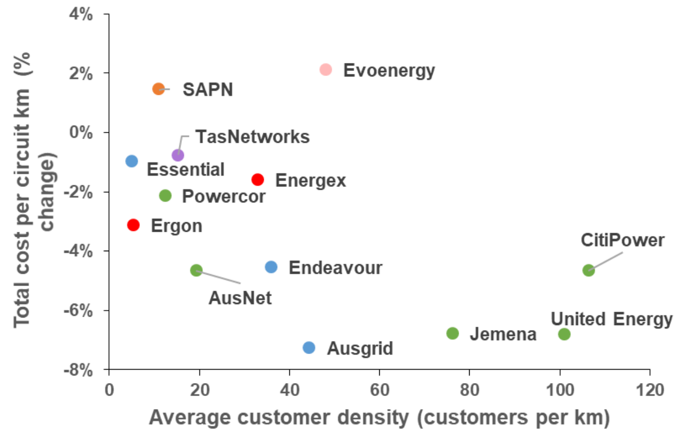


Figure 5.7 Percentage change in maintenance opex per circuit km PPI

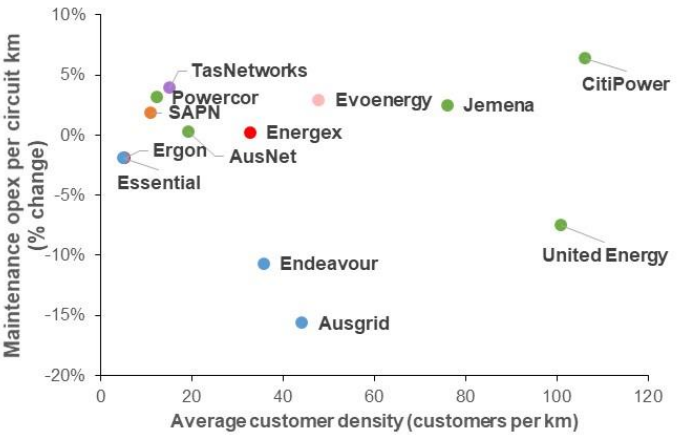


Figure 5.8 Percentage change in vegetation management opex per overhead km PPI

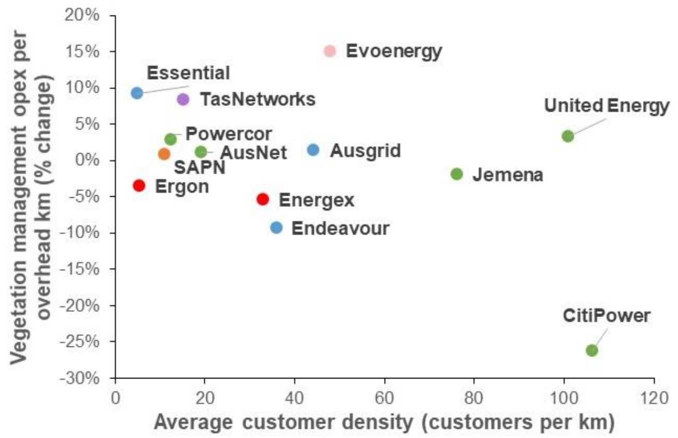


Figure 5.9 Percentage change in Emergency response opex per circuit km PPI

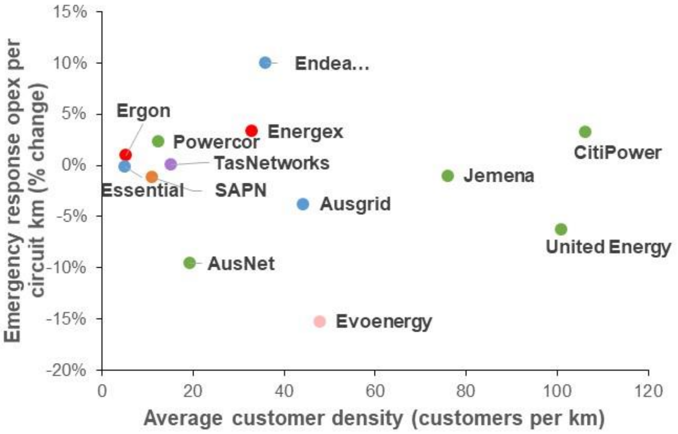
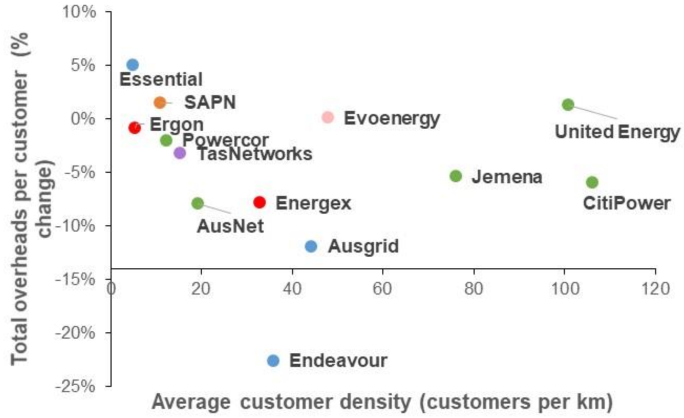


Figure 5.10 Percentage change in total overheads per customer PPI



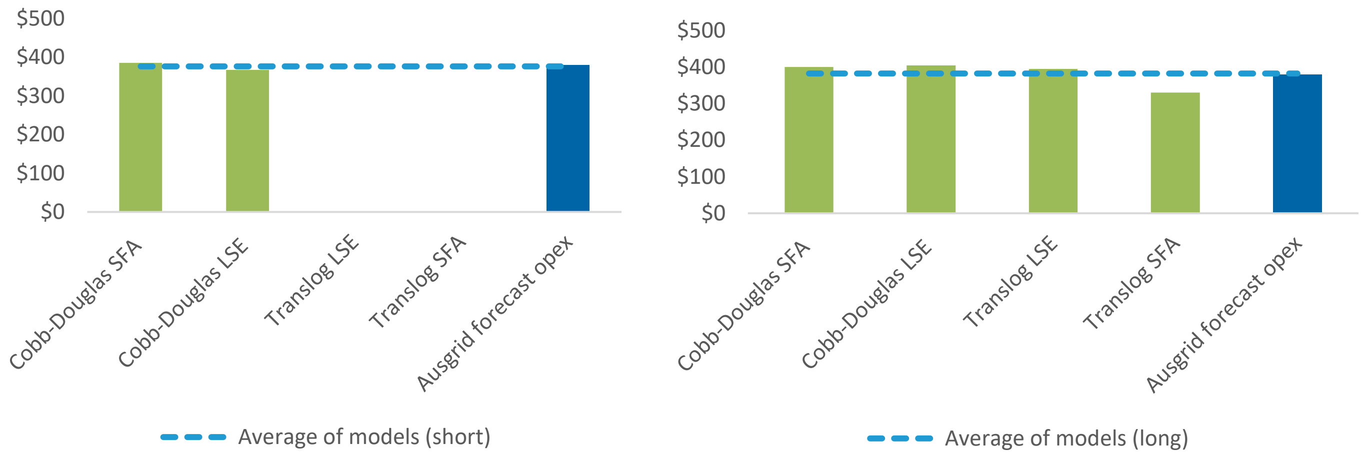
Source: Calculations using data from AER 2022 benchmarking

While Ausgrid is not currently amongst the most efficient DNSPs based on the longer-term MPFP and efficiency score measures, we have been making larger improvements in proportional terms than nearly all other DNSPs across the PPI measures the AER considers. This further demonstrates that our efforts to reduce opex in the current and previous regulatory periods resulted in us improving our efficiency. As a result, the AER and our customers can have confidence that our transformation program achieved levels of opex that are consistent with our peers, promoting our objective of keeping our network bills affordable without compromising network safety or reliability.

5.2.2 Efficiency assessment of Ausgrid's base year

We used the AER's opex roll forward models, and the latest benchmarking results, to estimate whether our base year can be considered efficient, or not materially inefficient, according to the AER's preferred methodology. **Figure 5.11** compares our base year opex with the efficient opex for both the long and short periods. We consider this shows that our FY23 forecast opex of $380 million (nominal) meets the efficiency criteria. In pre-submission engagement, AER staff indicated informally that our proposed FY23 forecast opex is likely to be considered not materially inefficient.

Figure 5.11 Base year efficiency ($m, real FY23; short period LHS, long period RHS)



5.3 Base year adjustments

5.3.1 Updated CAM

In October 2022 Ausgrid submitted a revised CAM to the AER to apply from 1 July 2024, which the AER approved on 26 October 2022. The new CAM results in some costs moving between lines of business, with a net movement of $7.3 million to SCS opex in the FY23 base year. We added this amount as a base year adjustment. The capitalisation policy has not changed, therefore there is no movement between capex and opex because of the CAM change. We recast **Table 3.2.2** in **RIN.10 – 2024-29 – Reset RIN – workbook 2 – historical data** for the current regulatory period to show the difference between opex under the old and new CAMs.

We calculated the adjustment amount by comparing opex under the current CAM with opex under the new CAM for five years, from FY19 to FY23. The data is shown in **Attachment 6.1.b – Step changes model**.

5.3.2 Emergency response

We also propose a base year adjustment to account for nature-induced emergency response costs on the basis of a five year average, rather than a single year estimate. This is because costs to respond to major events such as storms can be highly variable from year to year, and the amount included in our base year is lower than the average level we have experienced over recent years.

We calculated an adjustment of $4.4 million for this adjustment. This is the difference between the five year average of nature induced emergency response costs between FY18-FY22, excluding the amount of the pass through received for storms in FY20, and the amount included in the FY23 forecast for the same category. The calculations are shown in **Attachment 6.1.b – Step changes model**.

5.3.3 SaaS

In April 2021, the IFRIC released prescriptive guidance in relation to the treatment of costs associated with implementing SaaS IT solutions. In particular, the IFRIC clarified that such costs cannot be capitalised as an asset if an entity does not control the software. This is a change from our previous accounting treatment where such costs have been capitalised. It means that these costs must now be treated as opex.

This decision reflects the consistent evolution of software companies towards cloud-based subscription technology. Ausgrid, like other companies, continues to transition its technology landscape from on-premise technology solutions to cloud-based solutions. This means a lower total cost of ownership, but an increase in opex implementation costs and subscription fees.

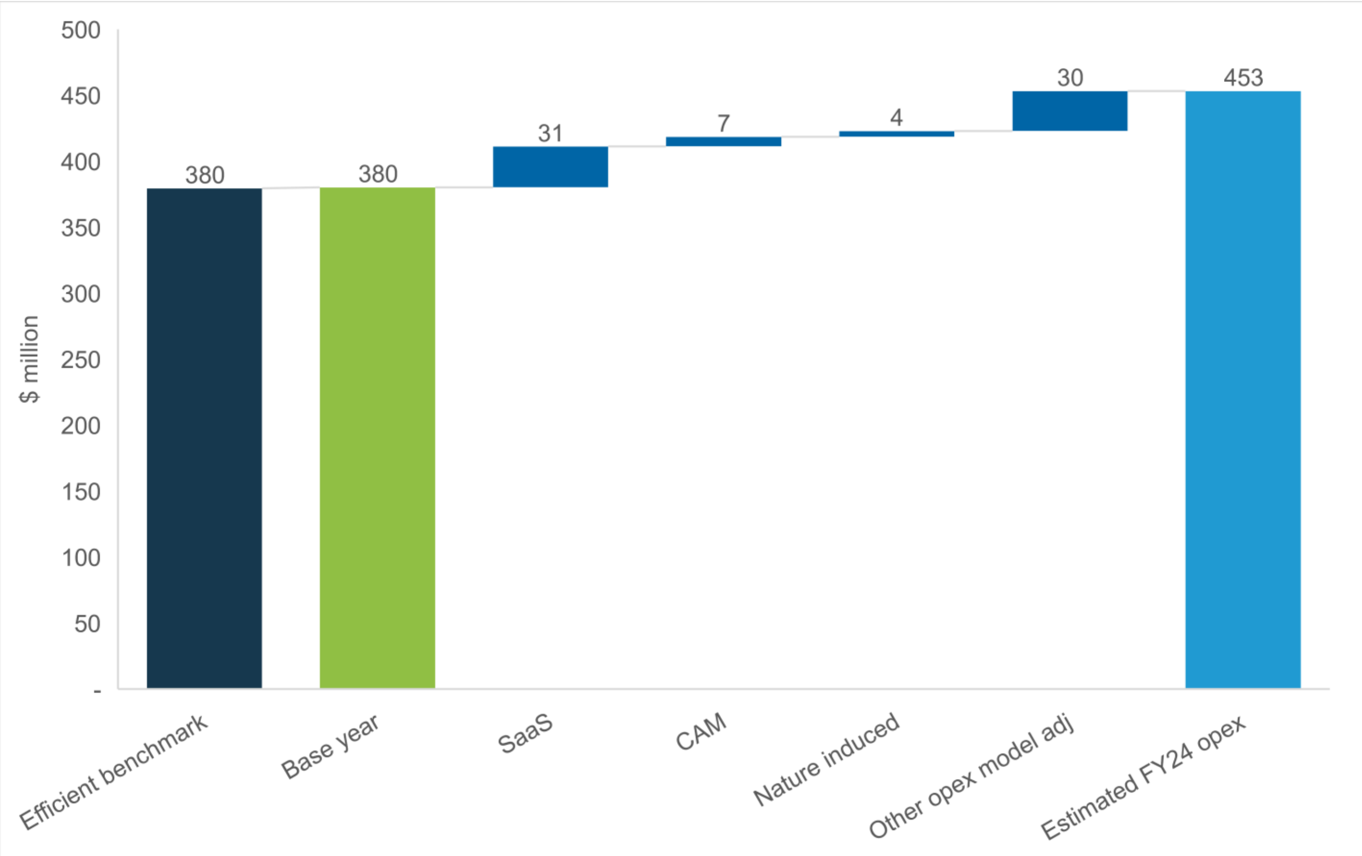
We have followed AER guidance that we should continue to treat costs identified as SaaS under the new guidance as capex in the current period for regulatory purposes, and change to opex in the 2024-29 period.[18] Our analysis for the 2024-29 period identifies and quantifies the split between opex and capex implementation costs for ICT projects that include SaaS solutions to be $154.7 million and $115.8 million respectively (see discussion of capex ICT costs in **Attachment 5.1 – Proposed capital expenditure**). We overlaid the IFRIC decision after we forecast total costs for ICT projects for the 2024-29 period and moved SaaS implementation costs from capex to opex.

The base year adjustment has been calculated as the average of the five year opex expenditure, at $30.9 million per year. This was originally treated as a step change to base year opex in our Draft Plan consultation. Following discussions with the AER, it was deemed more appropriate to treat it as a base year adjustment.

5.3.4 Final year adjustment

The AER's opex model estimates final year opex—FY24 in our case—by adding an increment of the difference between the AER's allowances between the base year and final year onto our efficient base year operating expenditure and adjusting for inflation, consistent with the AER's opex model. This model uses the final year forecast as the base to forecast next period opex. **Figure 5.12** shows the adjustments used to estimate FY24 opex.

Figure 5.12 Estimate of base year efficiency and FY24 opex ($m, nominal)



[18] AER staff have also indicated that the accounting change for operational leases from opex to capex should be treated as opex in the current period, and changed to capex in the 2024-29 period. This would mean that for one lease we would not recover the efficient cost as either capex or opex, and would also trigger an EBSS penalty. We have therefore not adopted this approach in our regulatory proposal. We would welcome further discussion with AER staff on this point.

6. Step changes

Step changes refer to increases or decreases in our opex associated with meeting new or changed regulatory obligations or opex/capex trade-offs. These factors represent forecast opex not captured by the base year expenditure or trend escalation, and therefore they are added to or subtracted from the trend-adjusted base year.

We are proposing the following seven step changes for the 2024-29 period based on the step change categories set out in the AER's Better Resets Handbook[19] of new regulatory obligation, capex to opex substitution or major external factors. **Figure 6.1** summarises the proposed step changes and associated AER categories:

Figure 6.1: Summary of proposed 2024-29 period opex step changes

Step change	Description	AER category
Insurance premiums	Risk management to address increasing insurance premiums due to cyber security and climate events such as bushfires and floods causing more damage to our network	Major external factor
Community resilience	Investigate community solutions other than network capex through community engagement, coordination with other resilience actors, and research / trials for alternate solutions	Capex to opex
Cyber security	Uplift our capability to respond to the frequency and severity of cyber attacks	New regulatory obligation
Smart meter data	We need to purchase smart meter data that is not in our base year due to increased smart meter uptake on our network as a result of the Australian Energy Market Commission's (**AEMC**) Review of the regulatory framework for metering services (**AEMC's Metering Review**)	Major external factor
Network Innovation Program (NIP)	Replacing NIP capex for opex to enable research and development through partnership	Capex to opex
ICT enablement program for CER integration	Delivering some projects in the ICT enablement program for CER integration as opex rather than capex	Capex to opex
Property strategy	Remove opex associated with property disposals in the current period	Negative step change

We are considering another step change which may be proposed at the time of our revised proposal. It relates to education programs regarding tariffs and the benefits of smart meters, so that customers – particularly vulnerable customers – can benefit from pricing structures that can reduce their electricity bills. We have not included it in this proposal because the scope would depend on the outcomes of the AEMC's metering review, which is not expected until later in 2023.

The proposed costs for each step change reflect forecast efficient expenditure not captured by base year opex, or output and real price growth, which would be incurred by a prudent service provider acting efficiently to achieve the opex objectives and meet the opex criteria in the NER. The following sections provide further information on each of our proposed step changes and describes how we explored them with customers.

[19] AER (2021), *Better Resets Handbook*, p 28.

We note these step changes were selected as a result of detailed engagement with the RCP and that we also proposed several other step changes for inclusion in this regulatory proposal that we did not progress further (see **Section 6.1** below).

Figure 6.2 Proposed opex step changes 2024-29 ($m, real FY24)

Step change	FY25	FY26	FY27	FY28	FY29	Total
Insurance premiums	0.8	1.8	2.3	2.5	2.1	9.5
Community resilience	1.1	1.7	2.1	1.9	1.7	8.4
Smart meter data	3.6	4.3	5.0	5.6	6.3	24.9
Network Innovation Program (NIP)	1.0	1.0	1.0	1.0	1.0	5.0
Cyber security	2.4	4.0	4.4	4.7	5.1	20.6
ICT enablement program for CER integration	0.9	2.1	2.2	2.5	2.6	10.4
Property strategy	(2.9)	(2.9)	(2.9)	(2.9)	(2.9)	(14.5)
Total	**6.9**	**12.0**	**14.2**	**15.3**	**15.9**	**64.2**

6.1 What customers told us

We engaged with the RCP in developing our proposed opex forecast and discussed potential step changes with them in detail several times over 2021 and 2022. In these discussions, we explored a range of step changes – some of which we have included in this Regulatory Proposal. **Figure 6.3** below outlines step changes we considered and decided not to progress after consultation with the RCP and discussions with AER officers.

Figure 6.3 Step changes considered, but not progressed

Step change considered	Why not progressed further
SaaS implementation costs	International accounting guidance released in FY21 requires the cost of configuring and customising software within SaaS arrangements to be expensed rather than capitalised. We consulted on this as a step change in our Draft Plan, however subsequent discussions with AER officers indicates we should treat this as a base year adjustment.
New culturally and linguistically diverse, low income and vulnerable customer support programs	While this was a strong theme within submissions to our Draft Plan and from Voice of Community Panel customers, the Reset Customer Panel did not support a specific step change. We note the AER's gamechanger initiative is yet to be finalised and may have implications for our Revised Proposal.
New license conditions obligations from 1 July 2024 that increase customer guaranteed service level (GSL) payment thresholds and obligations	The Reset Customer Panel asked us to absorb any incremental costs.
New regulatory obligations managing NSW Electricity Infrastructure Roadmap exemptions obligations	Any incremental costs associated with administering this scheme (for example, managing exemptions data and contribution orders, and communications) will be absorbed.

Step change considered	Why not progressed further
New obligations under the AEMC's Metering Review where there was potential that DNSPs would be responsible for site remediations	Given that the AEMC paused its metering review, we only progressed with a step change for purchasing smart meter data for network visibility (see **Section 6.5**). We will await the outcomes of the review early in our 2024-29 period.
New resources and systems to implement distributed system operator and CER obligations under the AEMC's access, pricing and incentive arrangements for CER rule determination	As there was no strict obligation from this rule change, this proposed step change was initially rejected by the RCP, however in refining analysis it evolved into the step change for ICT enablement program for CER integration as a capex to opex substitution (see **Section 6.7**).

As discussed in **Section 2.2**, we sought comments on our proposed step changes in the Draft Plan and tested them further with the RCP. We have made some adjustments to our forecasts in response to this feedback, which is set out in the following sections.

6.2 Insurance premiums

6.2.1 Context

Insurance costs are increasing. For us, key drivers of these increases are climate change, which is causing more damage to networks, and the significantly higher risk of cyber security breaches.

Our insurance premiums have increased by 87% over the last two years and are forecast to increase another 46% between now and FY29, even with concerted efforts to manage these costs. For this reason, we have included a step change of $9.5 million to our insurance costs so we can continue to appropriately manage risk at the lowest sustainable cost.

6.2.2 Justification for the step change

We obtained a report from our insurance consultants Marsh which provides detailed information on the market for all insurances obtained by Ausgrid – see **Attachment 6.3 – Marsh insurance report**. Marsh has also forecast our insurance costs to FY29, and these forecasts form the basis of our step change amount.

The Marsh Insurance Report's analysis and advice uses material including:

- Ausgrid's insurance policies and current premiums;
- Marsh's market research and analysis; and
- Insurance industry references and Marsh's experience with other utility companies.

It forecasts material increases in general liability (bushfire), professional indemnity, directors' and officers' liability, industry special risks for property and cyber across the 2024-29 period. Key drivers for the increases are:

- Rising incidents of natural disasters, including bushfire and flood claims, causing some insurers to exit the market;
- Reduced capacity as the industry shifts to aggregate limits across the risk portfolio; and
- Reduced ability of insurers to share risk due to rising reinsurance costs and reduced treaty exposures.

We included an insurance premium opex step change of $27.8 million in our Draft Plan. The step change in the proposal has been reduced by $18.3 million to $9.5 million due to:

- Advice from the AER that the step change should be calculated relative to our insurance spend in FY24, rather than our base year FY23 ($6.2 million). While we have aligned to this request in our proposal, we ask the AER to provide more detail behind the reasoning for calculating relative to FY24 and how this affects current and future period opex and EBSS;
- Updated forecasts by Marsh, taking into account of the outcomes of our FY23 renewal negotiations ($7.6 million);

- Excluding RAB growth from forecasts related to asset growth ($1.7 million); and
- Changes to inflation forecasts ($2.8 million).

This step change is driven by a major external factor outside of our control and does not include (i.e. double count) forecast growth that is already accounted for in the trend factor. Further, the efficient costs of this step change are not provided by other components of our total forecast opex, including base year opex. Ausgrid's total forecast opex will not allow us to achieve the opex objectives and reflect the opex criteria unless this step change is included as it is required for us to continue to appropriately manage risk at the lowest sustainable cost.

6.2.3 What customers said

Due to the commercial-in-confidence nature of our insurance premiums we did not discuss or share the Marsh Insurance Report with VoC Panel members. Instead, we engaged the RCP in detailed briefings on this opex step change, including conducting detailed Q&As on the Marsh Insurance Report and understanding the ways in which Ausgrid could mitigate increasing insurance premium risks over time. The RCP robustly challenged our approach to insurance by challenging the value customers receive from insurance, and asking Ausgrid to think about alternative ways of mitigating or managing risk in the face of increasing premiums. The RCP did not indicate concerns with the level of the step change.

6.3 Community resilience

6.3.1 Context

In response to the increasing intensity and frequency of extreme weather events, we have planned a range of initiatives to improve our climate resilience. These include:

- Run resilience education and grant style programs;
- Help communities with resilience planning;
- Conduct further research on vulnerable communities and extreme heat to address gaps in our existing modelling; and
- Support the communities we serve after an extreme weather event.

Forecasting the cost of these initiatives started with developing an efficient level of capital expenditure needed to address our expected growth in climate related risk (see **Section 5.5.4** of our **2024-29 Regulatory Proposal** and **Section 7** of **Attachment 5.1 – Proposed capital expenditure**). In line with the AER's Better Reset Handbook, we then considered the scope for prudent trade-offs between capital and operating expenditure.[20] This has led us to propose a $8.4 million opex step change for the implementation of community-based resilience initiatives, fully offset by a reduction to our 2024-29 capex forecast.

This is included this as a step change because we do not have any opex of this nature in the FY23 base year. The opex-based solutions making up our proposed community resilience step change predominately involve the cost of new staff with a specialist skillset. These new staff would run resilience education and grant style programs, help communities with resilience planning, do further research on vulnerable communities and extreme heat, and support the communities we serve after an extreme weather event.

Our proposal aligns to the engagement we have had with customers to date. The VoC Panel told us that they wanted a spectrum of resilience solutions which included a mix of capex initiatives partnered with more flexible opex solutions that support communities before, during and after an extreme weather event.

More recently, we came to the joint view with the RCP that further engagement is needed. This prompted us to develop a plan for implementing our Climate Resilience Framework, that builds on the conversations we have been having with customers. This implementation plan is summarised in **Section 5.5.4** of our 2024-29 Regulatory Proposal. The feedback we hear from customers may lead us to update our proposed opex step change, with any updates to be provided to the AER before its Draft Decision. **Figure 6.4** includes the expenditure breakdown for this step change.

[20] AER (2021), *Better Resets Handbook*, section 4.2.2.

Figure 6.4 Community-based climate resilience programs ($m, real FY24)

Program	Amount
Climate impact lab testing	$0.5
Real time community resilience warnings	$0.9
Research into community vulnerability	$0.7
Co-funded community resilience plans	$1.4
Community education campaigns	$1.3
Community resilience grants	$0.6
Mobile community liaison centres	$0.9
Workforce protocols and PPE for climate extremes	$0.7
Climate Impact Assessments	$0.2
Local temporary safety messaging	$0.5
Standards, processes, supply chain management improvements	$0.2
Establish asset protection zones for substations	$0.5
Total	**$8.4**

6.3.2 Justification for this step change

Our resilience program is an increasing priority for our network and customers. The step change could be justified as an efficient capex/opex tradeoff or as a major external factor category due to climate change. It is also strongly supported by customers who requested a balance of capex and opex based resilience solutions during extensive consultation, including workshops, joint consultation papers with other DNSPs and VoC Panel discussions.

Our total forecast proposed community climate resilience programs opex of $8.4 million is based on customer feedback that the bill impact of total resilience expenditure should be split 40:60, whereby 40% of our resilience spend is for community-based resilience opex programs and 60% is based on capex network investments. We consider this amount to be prudent and necessary to maintain network resilience and reliable services over the forthcoming regulatory control period.

Our total forecast opex will not allow us achieve the opex objectives and reflect the opex criteria unless this step change is included as it will allow us to achieve an efficient capex/opex trade-off for resilience expenditure. It will also allow us to meet our customers' changing expectations of how we manage and respond to extreme weather events.

We will continue to consult with our customers on the appropriate quantum for the step change as part of our climate resilience consultation for our Revised Proposal.

6.3.3 What customers said

Customers were very clear that we need to respond to the threats of climate change on our network and support communities. This included feedback that we need to:

Start to be proactive, think about the long term – start to rebuild more resilient. Large Customer.

Pursue an efficient mix of capital and operational investment opportunities to ensure the ongoing reliable provision of electricity
Voice of Community

[Provide] *nominated resilient localised community centres for people to go to*
Local councils

Our VoC Panel confirmed that their desire is for Ausgrid to provide support during major weather events which we are proposing to deliver through this step change.

In FY22, Ausgrid ran several workshops with our VoC Panel to assess the level of investment that the VoC Panel considered prudent for Ausgrid to make in the 2024-29 regulatory period, including consideration of resilience related expenditure. The VofC Panel provided feedback that around $40 million per annum on resilience-related expenditure (capex and opex) during the forthcoming regulatory period would be prudent. There was strong support from the VoC Panel for Ausgrid to propose resilience solutions that comprised of both capex and opex related investments.

In FY23, we continued with our engagement with the Voice of Community Panel on:

- What climate risks they were most concerned about and why;
- What outcomes they valued most; and
- Where Ausgrid should invest to improve climate resilience.

The feedback the VoC Panel provided on these issues are summarised in **Figure 6.5**.

Figure 6.5 VoC feedback on climate resilience

Topic	VoC Panel Feedback
Climate risks the panel was most concerned about	All climate risks are of concern Network-initiated bushfires,[21] long outages, and regional areas being more exposed to climate risks and therefore needing more resilient solutions Flood risk including community access to electricity, damage to houses/infrastructure, access issues, and better planning for backup power in flood prone areas Heat risk including building standards, animals, and vulnerable people such as the elderly or people with disabilities
Most valued outcomes	Education, communications and plans to address climate risks are highly valued, across different languages
Areas Ausgrid should invest in	Maps of high-risk areas and up to date modelling data should be used to inform investment decisions Investment in 'community resilience hubs' to address heat risks Communications from Ausgrid during storms is important, and we should be investing in early warning systems and harder assets for areas exposed to more frequent damaging wind events

Figures 6.6 and **6.7** summarise the weightings the VoC Panel placed on desired resilience outcomes and investment focus areas for climate resilience solutions.

Figure 6.6 VoC Panel feedback on desired resilience outcomes

Outcomes	Weighting allocated based off importance to VoC
Significantly reduce climate related outages and impacts for those most exposed (small # of customers benefit)	30% of customer dollars on resilience should be spent on this
Moderately reduce climate related outages and impacts for a higher number of people (medium # of customers benefit)	30% of customer dollars on resilience should be spent on this

[21] Network initiated bushfires are covered in **Attachment 5.4.e – CBA approach for replacement program**.

Outcomes	Weighting allocated based off importance to VoC
Have better support services available to all customers before, during, and after climate events (high # of customers benefit)	40% of customer dollars on resilience should be spent on this

Figure 6.7 VoC Panel feedback on desired investment focus

Areas	Weighting allocated based off importance to VoC
Areas where extreme weather impacts the most	34% of customer dollars on resilience should be focused on these areas
Areas where there is expected to be the biggest increase in outages due to extreme weather	28% of customer dollars on resilience should be focused on these areas
Areas where people are vulnerable and less able to cope with the impacts of increasingly extreme weather	38% of customer dollars on resilience should be focused on these areas

In response to this feedback, we have included a suite of programs to improve climate resilience that are both capex and opex to ensure that the most cost-effective option is considered when improving the resilience of the network and community to climate change. Specifically, our proposed climate resilience expenditure addresses customer requests for:

- Community based programs that help build community resilience; and
- Partnerships with other resilience actors.

Ausgrid has already started to respond to this feedback by partnering with Minderoo Foundation's Fire and Flood initiative to develop community resilience plans in two high risk areas of our network. We intend to use this initiative as a pilot and continue the work in the 2024-29 period.

In submissions to our Draft Plan, local councils were particularly supportive of these initiatives and welcomed the opportunity to engage with Ausgrid further to develop community-based resilience programs.

6.4 Cyber security

6.4.1 Context

In response to the frequency and severity of cyber attacks, we plan to invest in a cyber program that would enable us to adopt practices and protections in line with industry best practice (Security Profile 3 (**SP-3**) of the Australian Energy Sector Cyber Security Framework (**AESCSF**).

There are requirements under the recently amended *Security of Critical Infrastructure Act 2018* (Cth) (**SOCI Act**) which place new and enhanced regulatory obligations on Ausgrid. For example, it requires Ausgrid and other entities to implement and maintain a critical infrastructure risk management program (**Risk Management Program**) that addresses a range of prescribed risks, including cyber security. [22] The Risk Management Program must: [23]

- Identify hazards that present a material risk to the availability, integrity, reliability and confidentiality of critical infrastructure assets, or information about, or stored in, those assets;
- Minimise risks to prevent incidents (so far as it is reasonably practicable to do so);
- Mitigate the impact of realised incidents (so far as it is reasonably practicable to do so); and
- Implement effective governance and oversight procedures, including testing and evaluation, relating to security.

[22] See e.g., *Security of Critical Infrastructure Act 2018* (Cth), ss 30AC - 30AF, 30AH.
[23] *Security of Critical Infrastructure Act 2018* (Cth), s 30AH.

Further, the *Electricity Supply Act 1995* (NSW) (**ES Act**) was amended in 2021 to:

- Extend the power of the Premier to declare an electricity supply emergency if there is a 'cyber security incident' that affects electricity supply – including in relation to an incident that affects or is likely to affect a distribution system or a distributor (*ES Act*, s 94A(c));
- Enable the Minister for Energy and Environment to direct a network operator, electricity generator or other prescribed person to take certain action to respond to or prevent a cyber security incident (*ES Act*, s 94BA); and
- Enable the regulations to provide for the adoption and implementation, by a network operator, electricity generator or other prescribed person, of cyber security policies and procedures (*ES Act*, s 181A).[24]

SP-3 will best prepare Ausgrid and our network to implement and maintain the required Risk Management Program in the SOCI Act and respond to an ES Act electricity supply emergency declaration, should one occur. It will also minimise our exposure to cyber risks (generally) in the first place, relative to lower security profiles.

We note the AER's recent Draft Decision on Transgrid's transmission revenue determination for the 2023-28 period[25] which includes:

> *We agree with Transgrid and consider it prudent for Transgrid, as a transmission network service provider, to uplift its security and particularly to achieve SP–3 maturity. This is also supported by our consultant, Energy Market Consulting associates (EMCa), who provided expert advice on the assessment of this step change. EMCa considers that it is appropriate for Transgrid to achieve an AESCSF maturity indication level of SP–3 based on the combination of legislation, appropriate risk management, and the urgent request of the Australian Cyber Security Centre to adopt an enhanced cyber security posture.*

6.4.2 Justification for this step change

We aim to deliver an experience for our customers that takes advantage of digital technologies, while still maintaining a reliable network service with robust protections against the growing risk of cyber security breaches.

In light of the above regulatory changes and increasing cyber threats Australian businesses continue to face, we consider SP-3 to be the prudent maturity level for our business to adopt. This is based on our analysis using an Australian Energy Market Operator (**AEMO**) criticality assessment tool (see **Figure 6.8**). This tool assisted our assessment of our relative criticality in the electricity sector and to determine the appropriate target security profile level from the Australian Cyber Security Centre. The tool required us to assess a range of criticality factors.

It is also prudent to move to SP-3 from a customer impact perspective, by virtue of the interdependencies across sectors and potential for cascading consequences to other critical infrastructure assets and sectors if disrupted. Our network powers essential services, like wastewater treatment and hospitals, and supplies an area recognised as the third largest market for data centres in the Asia Pacific region and the 8th largest internationally (including the Sydney Central Business District (CBD).[26] We consider that this assessment of our already high risk and high consequence as critical infrastructure, compounded by the recent increase in high profile cyber attacks on Australian communities and businesses, means that this step change meets the AER's requirements for a regulatory requirement step change and a major external factor step change.

We consider the efficient costs of this step change are not provided by other components of Ausgrid's total forecast opex. For example:

- The costs we will incur to reach SP-3 by FY29 are not captured in our FY23 base year;
- The econometric measures for capturing output growth do not incorporate growth in regulatory obligations relating to cyber security; and
- We have only applied real price growth to labour.

The total forecast opex will not allow Ausgrid to achieve the objectives in NER clause 6.5.6(a) unless this step change is included because without the additional funding, our compliance with new requirements in the SOCI Act and ES Act

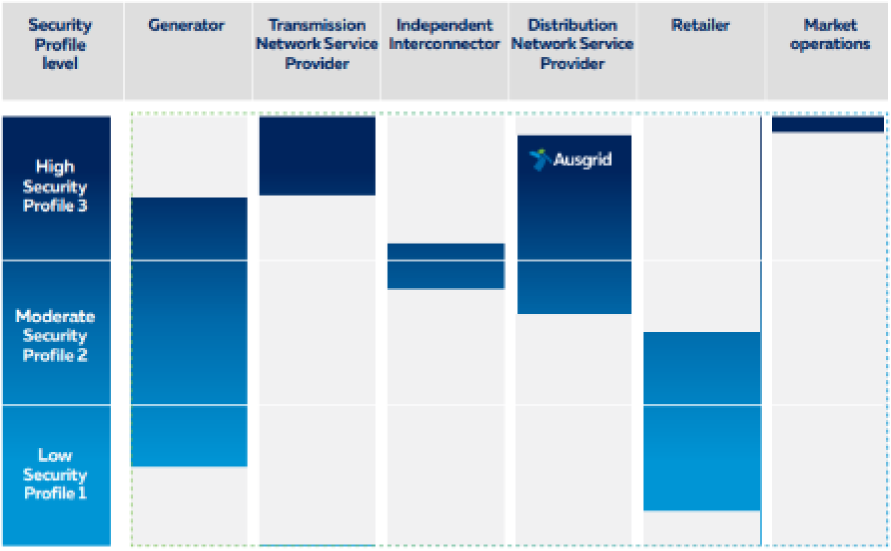
[24] *Energy Legislation Amendment Act 2021 No 34* (NSW).
[25] AER (2022), *Transgrid 2023-28 – Draft Decision – Attachment 6 – Operating expenditure – September 2022*, p 22.
[26] Cushman & Wakefield (2022), *2022 Global Data Center Market Comparison Report*.

would be put at risk. Further, if funding was diverted from other areas of our business to comply with the new regulatory obligations under the SOCI Act and ES Act, then we would not have sufficient funding to maintain the quality, reliability and security of standard control services.

The total forecast opex will not reasonably reflect the criteria in NER clause 6.5.6(c) unless this step change is included because, given the evolving nature of cyber security threats and ratcheting regulatory obligations, a prudent operator would require an increase in our FY23 base year opex to meet the operating expenditure objectives in the NER.

To identify and quantify this step change, we undertook a process where we assessed our current level of cyber security maturity against the additional practices we would have to implement to reach SP-3. Our cost benefit analysis demonstrates that we propose to address this step change in a prudent and efficient manner because it achieves the highest economic outcome compared to the other options we considered.

Figure 6.8 Ausgrid's self-assessed cyber security criticality rating



Source: Ausgrid analysis based on AEMO's 2022 AESCSF framework and resources

6.4.3 What customers said

In our engagement to inform our Draft Plan, our customers and stakeholders were unanimous in their view that we should improve our resilience to a cyber attack. However, they did not initially reach a consensus on the appropriate level of protection for our business by the time we went out for consultation on our Draft Plan. Only the RCP and some members of our VoC Panel considered SP-3 was necessary. Other members of the VoC Panel were not convinced given the cost of this level of protection.

In our Draft Plan, we indicated that we were considering investing in a SP-3 program as this would allow us to take greater advantage of digital technologies to improve our customers' experience when interacting with us, while still maintaining a reliable network service with robust protections against the growing risk of cyber security breaches. In addition, given the high economic, social, health and geopolitical ramifications of a catastrophic cyber attack on our network (which serves Sydney's CBD), we considered this was the most prudent level of protection for our business and customers. Our VoC Panel formed a consensus to support SP-3.

Further detail of customer feedback on our proposed ICT expenditure to address cyber security is provided in **Section 5.9.2** of our **2024-29 Regulatory Proposal**.

Given this customer and stakeholder support, we have included a step change of $20.6 million in addition to our recurrent cyber security costs so that we can improve our cyber protections in line with industry best practice and achieve SP-3. The cost of the forecast step change is primarily based on additional cyber software licencing and resourcing costs in line with the incremental cyber controls based on typical delivery team resource requirements and partner costs. We will take a staggered approach, reaching Security Profile 2 in FY27 and progressing to SP-3 by FY29.

6.5 Smart meter data

6.5.1 Context

We plan to invest $24.9 million in smart meter data and real-time smart meter functionality that will enable us to better understand two-way energy flows associated with CER and monitor potential electricity faults that can cause safety hazards.

More data and additional real-time, smart meter functionality will also lead to:

- More efficient growth capex through more granular and timely information on our low voltage network, resulting in faster and more accurate decision-making;
- Lower opex through a reduction in customer callouts for safety related matters
- Enhanced safety benefits through neutral integrity monitoring and life support validation; and
- Enhanced customer benefits by reducing the curtailment of customers' CER exports.

The amounts are based on the price per meter we are currently paying under our innovation program to test safety outcomes for customer installations, service connections and the network.

The quantity of data available to purchase is linked to the rollout of smart meters. Since the market led rollout of smart meters was implemented, take up has been slower than expected. However, the AEMC's Metering Review may result in a mandated accelerated rollout of smart meters, and the possibly of mandated access to 'meter enquiry' functionality. This would increase the availability of data for us to purchase. Noting that the AEMC has not made a final decision, we assessed three cost options based on meter uptake scenarios. We discussed the options with the RCP, and agreed an optimised meter take-up scenario which forms the basis of our step change.

6.5.2 Justification for this step change

Currently Ausgrid is only receiving data from 20,000 smart meters under the Network Innovation Program to test safety outcomes for customer installations, service connections and the network. We explored three scenarios for purchasing smart meter data based on our forecast understanding of smart meter uptake in our network and the corresponding cost to purchase smart meter data.

Figure 6.9 summarises this forecast and shows that Scenario 2 (optimised smart meter uptake) provides greatest value for money. This is because not all available metering data across the network is required for us to improve our network visibility due to factors such as multi-occupancy dwellings, but we need a sufficient amount to yield benefits from increased visibility.

Figure 6.9 – Forecast scenarios for smart meter uptake and purchasing smart meter data ($m, real FY24)

Scenario		FY23	FY24	FY25	FY26	FY27	FY28	FY29
1) Maximum smart meter uptake	**# Meters**	270,000	695,000	820,000	945,000	1,075,000	1,205,000	1,335,000
	Cost ($m)	0.55	6.82	7.70	8.57	9.49	10.64	11.49
2) Optimised smart meter uptake	**# Meters**	150,000	150,000	300,000	400,000	500,000	600,000	700,000
	Cost ($m)	0.44	2.88	4.04	4.74	5.45	6.09	6.75
3) Constrained smart meter uptake	**# Meters**	120,000	120,000	180,000	240,000	300,000	360,000	420,000
	Cost ($m)	0.33	2.78	3.20	3.62	4.04	4.32	4.71

While we anticipate being able to access more smart meter data during the 2024-29 period as the AEMC's Metering Review comes into effect, regulated access to this data may be limited to once per day. In our current trial, we are receiving data at least four times a day, which enables a far more granular understanding of our network. More frequent data is required to enable services such as dynamic pricing and dynamic operating envelopes. We expect that in the 2029-34 period, retailers will improve data sharing compliance and maturity, which will give Ausgrid access to more advanced data services that we can utilise to provide more value to customers through further operational efficiencies and new ways of working.

To determine the quantum for this step change, we developed a 'unit rate' (per meter) based on our existing commercial arrangements for smart meter data purchases. We then extrapolated that unit rate to the 'optimised smart meter uptake' volumes. Our cost benefit analysis demonstrates that we propose to address this step change in a prudent and efficient manner because our selected option delivers the highest net economic benefits.

This step change will enable more data and real-time smart meter functionality so we can:

- Implement more efficient growth capex through more granular and timely information about CER assets. This will result in faster and more accurate decision-making to integrate CER into our network so that these assets are better utilised and we can reduce the risk of curtailing CER;
- Have additional growth benefits through connectivity validation, voltage compliance and dynamic network management;
- More efficient use of resources through a reduction in customer callouts, outages and safety incidents; and
- Enhanced safety benefits through neutral integrity monitoring and life support validation.

This step change is driven by the major external factor of forecast higher CER uptake in our network and needing to increase visibility of our network to improve how we manage increased CER. This is combined with the lower than historically forecast uptake of smart meters, which the AEMC's Metering Review is not expected to ameliorate until the end of the 2024-29 period (in a best case scenario). In addition, as noted above, we expect to only receive data from retailers once a day, contrasted with the experience in Victoria where DNSPs are accessing data at least 4 times a day.

We consider the efficient costs of this step change are not provided by other components of Ausgrid's total forecast opex. For example:

- The cost to purchase additional smart meter data ('optimised meter uptake' scenario in **Figure 6.9** above) is not in our FY23 base year;
- The econometric measures for capturing output growth do not incorporate growth in new activities such as smart meter data purchases; and
- We have only applied real price growth to labour.

The total forecast opex will not allow Ausgrid to achieve the objectives in NER clause 6.5.6(a) unless this step change is included because our ability to maintain quality, reliability and security of supply of standard control services would be compromised. In particular, we will not have the funding to develop to the network visibility we require to integrate our expected growth in CER assets, without voltage and other technical issues emerging.

The total forecast opex will not reasonably reflect the criteria in clause 6.5.6(c) of the NER unless this step change is included because we will not be able to efficiently maintain quality, reliability and security of supply of standard control services, without the network visibility that our smart meter data acquisitions will offer.

6.5.3 What customers said

In our engagement to inform our Draft Plan, our customers and stakeholders told us we should proactively prepare our network for net zero and invest to reduce our long-term costs. Some stakeholders indicated that we should look to purchase all available data, which could in turn be provided to customers in a meaningful format. In response, our Draft Plan indicated that we were considering this investment in smart meter data and functionality, but only to a level that would still provide demonstrable benefit to customers. The costs and benefits of this investment will be reviewed on an ongoing basis to ensure that this remains appropriate.

In our engagement to inform this proposal, customers told us they agreed with the level and scope of investment we proposed in order to prepare the network for net zero and to help facilitate customers doing the same. The RCP noted the importance of smart meter data to detect safety issues, and that the safety benefits of smart meters have been significant in Victoria. The RCP was highly supportive of the use of smart meter data and questioned why we were not purchasing all smart meter power quality data rather than a subset (we explain the reasoning in **Section 6.5.2**). They also noted the AEMC's Metering Review is ongoing and that further changes were likely. In response to this feedback, we have not changed the level of expenditure of this step change.

6.6 Network Innovation Program

6.6.1 Context

As discussed in **Attachment 5.1 – Proposed capital expenditure**, the NIP comprises a range of trials and pilots covering leading edge energy technologies to support the rapidly evolving electricity sector, for a total capital investment of $49.5 million over five years. For the 2024-29 period, we plan to add an opex allowance to the program.

6.6.2 Justification for this step change

The efficient costs of this step change are not provided by other components of Ausgrid's total forecast opex because our base year opex does not include any expenditure for our NIP. Ausgrid's total forecast opex will not allow us to achieve the opex objectives and reflect the opex criteria unless this step change is included as it is required for us to broaden the scope of the existing NIP which currently only includes capex.

The NIP has significant potential benefits in delivering improved service to customers in an efficient and secure manner during the 2024-29 period. The opex innovation allowance will enable us to:

- Select the most efficient options for customers, particularly in the technology domain, with licence costs from the increasing trend towards SaaS and Product as a Service (**PaaS**) offerings; and
- Conduct ongoing research on community attitudes, expectations and preferences related to issues relevant to the Network Innovation Program, including solution options and equipment standards.

The expenditure is expected to also create long-term capex savings through the application of innovative solutions.

In order to determine the appropriate level of opex for the 2024-29 period, we forecast four scenarios that vary the level of capex included and how it is prioritised across different projects within the NIP portfolios, while keeping proposed opex relatively consistent in total but varying the amount spent within years.

Figure 6.10 shows our NIP options split by capex and opex expenditure and provides the net present value (**NPV**) benefits.

Figure 6.10 NIP options ($m, real FY24)

Program options		Capex	Opex	Benefits
Option 1: Do Nothing	• Cease Network Innovation Program and undertake traditional network investment only.	$0	$0	$0
Option 2: Full Network Innovation Program	• Undertake 100% of identified projects and all customer research across the three workstreams in order to maximise the total benefits. • This results in a proposed program that has a split between 60% trials and 40% pilots.	$82.3	$5.4	$70.4
Option 3: Optimised Network Innovation Program	• Undertake approximately 60% of identified projects and customer research across the three workstreams, prioritising those that have the largest expected cost benefit. • This results in a proposed program that has a split between 70% trials and 30% pilots.	$49.5	$5.0	$81.8

Option 4: Maximised breadth of Network Innovation Program	• Undertake approximately 70% of identified projects and customer research across the three workstreams, prioritising the largest breadth of Network Innovation trials. • This results in a proposed program that has a split between 80% trials and 20% pilots.	$59.5	$5.1	$79.8

6.6.3 What customers said

We consulted on the totex NIP in our Draft Plan, including the $5 million for opex, and received strong feedback from our VoC Panel that this planned level of expenditure was insufficient. We explained that the amount we spend on innovation is constrained by the number of personnel that we have to deliver these programs and our ability to prioritise innovation projects over business-as-usual service delivery projects.

We also consulted with our Network Innovation Advisory Committee to determine their recommended option. The Network Innovation Advisory Committee also supported Option 3 due to the proposed expenditure enabling them to oversee research into customer preferences and partner with specialist researchers.

Our cost benefit analysis demonstrates that we propose to address this step change in a prudent and efficient manner because the $5 million opex combined with the $49.5 million capex expenditure for the NIP, is expected to deliver $81.8 million in NPV relative to Option 1 (spending no opex or capex) and $11.4 million more in benefits than Option 2 which spends 8% more opex and 66% more capex. For more details on our proposed NIP see **Attachment 5.8.a – Network innovation program**.

6.7 ICT enablement program for CER integration

6.7.1 Context

In our Draft Plan, we proposed expenditure to invest in supporting higher uptake of CER. Some of this included upgrading ICT systems to enable CER integration, which was included as capex in our Draft Plan forecasts. We have since refined our strategy and believe we can deliver a better and lower risk outcome by delivering some of the projects as opex rather than capex. Therefore, while this is a new step change compared to our Draft Plan, it does not add to our total expenditure for CER projects.

In the Draft Plan, we included $34 million for ICT enablement capex for CER integration. We now propose $10.4 million of ICT enablement expenditure to be opex, and included this as a step change because we do not have any expenditure of this nature in the FY23 base year.

It is important to note that all programs within the CER integration expenditure category are interdependent. That is, if the capex elements are approved and the ICT enablement program and smart meter data opex are not approved, or vice versa, this will impact our low voltage network visibility such that we will not be able to deliver on the overall CER integration program.

6.7.2 Justification for this step change

Our ICT enablement program for CER integration over the 2024-29 period aims to build foundational capabilities needed to become a dynamic platform. This includes:

- Making improvements to our connections processes to support the anticipated increase in the number and types of CER customers we will connect to our network;
- Uplifting our modelling and forecasting capabilities to allow us to make as much network capacity available to customers as possible without breaching network limits. This will also take advantage of increased low voltage network visibility due to purchasing smart meter data as outlined in **Section 6.5** above; and
- Providing customers with more flexible network services options that rewards them for their flexibility through investing in dynamic operating envelopes and dynamic network pricing.

We went to market to understand how providers could deliver these solutions to us. From that analysis we found that a key consideration in the ICT enablement program is the capex to opex trade-off between opting for SaaS type solutions and building bespoke systems with lower ongoing operational costs. Based on responses from providers, we narrowed the scope down to 2 options that could deliver our ICT enablement program for CER integration.

Figure 6.11 summarises the spend profile for Options 1 and 2. Both options enable us to deliver the work program. However, the option with a larger amount of capex and smaller amount of opex (Option 2) is $18 million more expensive over the period. Option 1 also is our preferred option because it relies more heavily on SaaS solutions. This is preferable because it:

- Will allow us to leverage capabilities other networks have already developed and ensure any enhancements made for Ausgrid remains accessible to other networks;
- Presents a lower risk to customers than upfront investment if two-sided markets take longer to develop; and
- Has a lower spend profile over 2024-29, by $18m, which will help with affordability in the short term.

Although we are currently conducting a trial (Project Edith) to test and demonstrate these capabilities, it is funded through NIP capex and not included in our base opex.

Figure 6.11 Spend profile for options considered in ICT enablement program for CER integration ($m, real FY24)

Options		FY25	FY26	FY27	FY28	FY29	Total
Option 1	Capex	8.2	8.7	2.0	2.2	1.7	**22.8**
Totex: $33.2m	Opex	0.9	2.1	2.2	2.5	2.6	**10.4**
Option 2:	Capex	8.2	14.2	7.5	7.8	7.2	**44.9**
Totex $51.2m	Opex	0.9	1.5	1.1	1.4	1.4	**6.3**

The efficient costs of this step change are not provided by other components of Ausgrid's total forecast opex. For example:

- The costs we will incur are not captured in our FY23 base year;
- The econometric measures for capturing output growth do not incorporate growth in CER assets; and
- We have only applied real price growth to labour.

Our total forecast opex will not allow us to achieve the opex objectives[27] unless this step change is included because our ability to efficiently manage and deliver services to CER customers would be compromised.

To identify and quantify this step change, we scoped the ICT requirements internally. Our ICT team then did an international provider scan to determine who would be able to deliver this work. We then had discussions with the two providers that our ICT team determined would be able to deliver the work. We sought informal quotes from them and tested them for their ability to be able to deliver the work. The proposed provider for the step change demonstrated an ability to understand and deliver to the project requirements relative to their counterpart. They were able to provide an upfront cost compared with a subscription based cost so we could better determine which approach would meet our needs. As a result, this was the most prudent and efficient provider based on market testing.

6.7.3 What customers said

Customers told us that we should be supporting a proactive approach to CER integration in our network that enables them to invest in CER and directly access and share its benefits with all customers. We did not specifically consult with customers on this step change in our Draft Plan as we had not yet received quotes from suppliers on how to deliver this work. However, customers consistently told us that they are supportive of us undertaking foundational investments

[27] NER, clause 6.5.6 (a)

to enable CER integration. Further information on customers' feedback on our CER integration expenditure is outlined in **Section 5.7** of our **2024-29 Regulatory Proposal**.

As a result of the cost benefit analysis (**CBA**) for this step change coming together after our Draft Plan consultation, we discussed this step change in detail with the RCP so they could understand the trade-off between capex and opex. The RCP advised that they understood and supported the strategic nature of the decision and agree networks should standardise their systems but wanted to see the detailed CBA.[28]

Additionally, this step change enables us to enact the RCP's and Pricing Working Group's support for introducing dynamic pricing.

6.8 Property

The property strategy negative step change arises from property sales in the current 2019-24 period that reduce land tax and other costs associated with properties sold.

6.8.1 Justification for the step change

This is a negative step change to reflect lower costs due to the sale of properties in the current period.

Customers benefit from property sales because the full disposal value is netted off the RAB. This means any uplift in value compared to the original value recognised in the RAB is fully passed through to customers through lower return on asset.

When preparing our 2024-29 Regulatory Proposal, we identified several properties that could be rationalised. We determined that it would be most prudent to achieve the sales as soon as possible, rather than offering the properties for sale over a number of years, including because:

- Property values are forecast to fall over coming years, therefore we can maximise the value returned to customers by selling over the coming year; and
- The benefit to customers comes sooner if a large portfolio of properties is removed from the RAB this regulatory period, rather than phased over the 2024-29 regulatory period.

To achieve the sales quickly, we will sell the properties to another company in the Ausgrid group. Being a related party transaction, the highest levels of probity will be adhered to, including procuring independent valuations for the properties to ensure maximum benefit is derived for our customers.

Each property owned by Ausgrid carries a certain level of opex, including land tax and maintenance costs. As we are forecasting to sell $151 million worth of properties, we have identified recurrent costs associated with those properties that we will not incur once they are sold. These costs include land tax, rates, utilities and maintenance, and is estimated at $14.5 million over five years. The amount will be updated in our revised proposal to reflect the actual sales outcome.

More information on our property strategy can be found in **Attachment 4.1 – 2024-29 proposed revenue**.

6.8.2 What customers said

We consulted with the RCP on this step change, which was supported as it results in a reduction to opex.

[28] The CBA was provided to RCP prior to submission of our Regulatory Proposal.

7. Trend

The next part of our approach to forecasting opex is to 'trend' our base year forward to take account of how opex changes over time. To do this we have considered:

- **Real price growth** – to reflect expected changes in the price of our cost inputs, including our labour costs;
- **Output growth** – to account for changes in costs based on how much output we expect to deliver; and
- **Productivity growth** – to reflect expected industry-wide improvements in finding more efficient ways of delivering services.

This approach is in line with the AER's Better Resets Handbook.[29] **Figure 7.1** summarises the trend factors.

Figure 7.1: Forecast rate of change (%)

Trend factor	FY25	FY26	FY27	FY28	FY29
Price	0.98%	0.89%	0.39%	0.30%	0.42%
Output	0.29%	0.37%	0.44%	0.84%	0.79%
Productivity	(0.50)%	(0.50)%	(0.50)%	(0.50)%	(0.50)%
Total	**0.76%**	**0.75%**	**0.33%**	**0.63%**	**0.71%**

7.1 Real price growth

Our base year opex reflects the current prices of cost inputs. Forecast opex needs to account for changes in the price of cost inputs to reasonably reflect a realistic expectation of the cost inputs required to achieve the opex objectives in the forthcoming regulatory period. These price increases may not necessarily be at the same rate as inflation. They may be higher or lower than inflation due to several factors. The need to adjust forward forecasts to account for real cost escalation is accepted by the AER as important in reflecting the opex criteria.

To incorporate expected movements in our labour costs, the AER's preferred methodology is to use an average of two state specific utilities industry wage price index growth forecasts for real labour inflation, including one engaged by the AER.[30] We asked BIS Oxford Economics (**BISOE**) to forecast the Electricity, Gas, Water, Waste Services (**EGWWS**) wage price index for NSW. As a placeholder for the AER's consultant forecast we have used the KPMG NSW utilities forecasts provided for the Transgrid draft decision.[31] This does not cover the last year of our regulatory period, so we have carried forward the FY23 forecast for FY24. We then applied real labour escalation to 59.2% of opex, aligned with the AER's methodology.

We expect to update our opex forecast with the latest forecast change in real labour costs in the revised proposal. See **Attachment RIN.05 - (BIS Oxford Economics – Real labour escalation report)** for the methods and data used to develop the forecasts. **Figure 7.2** shows the data and calculations to calculate the price growth factor.

Figure 7.2 Real labour price escalation

Item	FY25	FY26	FY27	FY28	FY29
BISOE (a)	1.21%	1.14%	0.86%	0.52%	0.93%
KPMG (b)	1.10%	0.85%	0.47%	0.48%	0.48%
Average (c) = (a+b)/2	1.15%	1.00%	0.66%	0.50%	0.71%
Superannuation guarantee increases (d)	0.50%	0.50%	0.00%	0.00%	0.00%

[29] AER (2021), Better Resets Handbook, pp 26-27.
[30] AER (2021), Better Resets Handbook, p 26.
[31] KPMG (2022), Wage Price Index Forecasts, 14 September.

Item	FY25	FY26	FY27	FY28	FY29
Average + Super guarantee increases (e) = c+d	1.65%	1.50%	0.66%	0.50%	0.71%
Weighting (f)	59.20%	59.20%	59.20%	59.20%	59.20%
Real price growth factor (g) = e*f	0.98%	0.89%	0.39%	0.30%	0.42%

7.2 Output growth

Output growth allows for gradual increase in opex to cover the costs of maintaining a growing network. The AER has a standard methodology for applying output growth which is informed by the econometric benchmarking discussed in **section 5.2.1**. The benchmarking demonstrates that the following variables are key drivers of cost changes:

- Customer numbers;
- Circuit length; and
- Ratcheted maximum demand.

Energy throughput was considered an output for the purpose of benchmarking, however no longer receives any weight in the modelling. We have applied the weightings produced by the AER's 2022 benchmarking[32] to calculate the output growth factor, as shown in **Figure 7.3**. The column headings refer to the 4 econometric models used in opex benchmarking.

Figure 7.3 Output weights

Factor	SFA CD	LSE CD	LSE TLG	SFA TLG
Customer numbers	43.12%	60.92%	45.14%	47.64%
Circuit length	10.78%	15.69%	17.24%	8.42%
Ratcheted maximum demand	46.10%	23.38%	37.62%	43.94%
Total output growth	100%	100%	100%	100%

Output growth has been applied in **Attachment 6.1.a – Opex model**. Our forecasts for the three relevant factors are consistent with forecasts in other parts of the regulatory proposal. For example, the circuit length aligns with the assumptions behind the capex forecast.

7.2.1 Customer numbers

For residential customer numbers, our forecast is based on the Housing Industry Association's dwelling starts forecast until FY25, and thereafter is based on household projections from the NSW Department of Planning and Environment. We forecast our non-residential customer numbers based on recently observed trends. The forecasts are in line with historic trends, as required in the Better Resets Handbook.[33] More detailed information can be found in **Attachment 8.1 – Our TSS Explanatory Statement for 2024-29**.

7.2.2 Circuit length

For transmission mains, we have used our forward forecast capital program overlaid on FY22 actuals to forecast the future length. For distribution mains, we have used a 5 year historical trend to forecast the future length.

7.2.3 Ratcheted maximum demand

Ausgrid develops and applies forecasts with differing perspectives at the different network levels depending on the analysis and decisions for which they are needed. These different types of forecasts are consistent in terms of the

[32] AER (2022), Annual benchmarking report – distribution network service providers.
[33] AER (2021), *Better Resets Handbook*, p 26.

underlying assumptions which are common between them, for example AEMO Integrated System Plan (**ISP**) scenarios, while including unique characteristics which address their particular focus area.

Ausgrid's maximum demand forecasts are based on the four AEMO ISP 2022 scenarios:

- Slow Change;
- Progressive Change;
- Step Change; and
- Strong Electrification.

Step Change has been identified as the most likely scenario in the 2022 ISP published by AEMO in June 2022. On this basis, Ausgrid has adopted the Step Change forecast as the most likely scenario on which to apply planning models and expenditure forecasts.

More detail can be found in **Attachment 5.6.a – Maximum demand forecast**, which has been independently verified by an external consultant (**Attachment 5.6.b – Ausgrid maximum demand forecast and DER integration model review**).

7.3 Productivity

A productivity factor reduces forecast opex on the basis that businesses will continuously find cost savings. This factor embeds a minimum level of cost reductions that are fully passed through to customers. We have included an opex productivity factor of 0.5% which aligns to the AER's expectations in the Better Resets Handbook,[34] and was consulted on with the RCP after a holistic discussion evaluating Ausgrid's overall proposal.

The approach taken by the RCP to productivity is contained in an attachment to their report. The RCP took a principle based approach which included considering interdependencies between capex and opex, how risk is shared between customers and Ausgrid, and how incentivisation should be applied for innovation and resilience. This led to us proposing a 0.5% productivity factor for capitalised overheads to reflect that capitalised overheads are of a similar nature to expensed overheads.

On top of the 0.5% productivity factor, there are other costs we have identified that are not in our base year and are not being proposed as step changes. **Figure 7.4** summarises these costs.

Figure 7.4 Opex costs not included in productivity factor ($m, real FY24)

Item	FY25	FY26	FY27	FY28	FY29	Total
Customer (GSL) payments	0.5	0.5	0.5	0.5	0.5	**2.7**
Graduates and apprentices	2.1	2.4	2.4	2.5	2.5	**11.9**
Total	**2.7**	**2.9**	**3.0**	**3.0**	**3.0**	**14.6**

- **Customer GSL payments** – as noted in **Section 6.1**, we raised the possibility of including a step change to account for higher costs following the Independent Pricing and Regulation Tribunal's (**IPART**) review into Electricity Distribution Reliability Standards, which changes our licence conditions from FY24 by increasing reliability standards and customer GSL payments. The RCP indicated they would not support such a step change, and Ausgrid agreed to absorb the higher costs. We note that in the current 2019-24 period we are absorbing system and implementation costs to manage the new requirements, for example additional reporting requirements for assessing outages of 3 minutes or more.
- **Graduates and apprentices** – during the enterprise bargaining agreement (**EBA**) negotiations Ausgrid agreed to employ more graduates and apprentices. Given the nature of this new expenditure we propose to absorb these costs.

[34] AER (2021), *Better Resets Handbook*, p 27.

8. Rule requirements

We proposed a total forecast opex for the 2024-29 period that we consider is required to achieve each of the opex objectives listed in NER clause 6.5.6(a). The AER is required to decide whether to accept or reject our total forecast opex. The AER must accept the total forecast opex if it is satisfied that the forecast of required opex reasonably reflects each of the opex criteria, having regard to the opex factors. Below we identify how we have met the opex objectives, criteria and factors.

The NER requirements in relation to forecast opex in a building block proposal are largely contained in NER clause 6.5.6. We outline how we have had regard to, and satisfy, these requirements in our regulatory proposal in **Figure 8.1** below.

NER clause S6.1.2 includes additional requirements for our opex proposal. We outline how we have addressed these requirements in **Attachment 2.4 - NER compliance table**.

Figure 8.1: How we address NER clause 6.5.6 requirements in relation to forecast opex

NER clause	Description of requirement (and related RIN requirements where applicable)	How we satisfy requirement
Opex objectives		
6.5.6(a)(1)	Our regulatory proposal must include the total forecast opex for the 2024-29 period that we consider is required to meet each of the opex objectives in NER clause 6.5.6(a) (**opex objectives**). **Note:** Reset RIN 4.6.1(a)(i) requires Ausgrid to provide justification for our total forecast opex, including why the forecast opex is required for Ausgrid to achieve each of the opex objectives.	We consider the total forecast opex proposed for the 2024-29 period as outlined in our proposal and this attachment is required to meet the opex objectives. **Section 8.1** below provides an overview of why we consider our proposed total forecast opex is required in order to achieve each of the opex objectives.
Miscellaneous		
6.5.6(b)(1)	Our forecast opex must comply with the requirements of any relevant regulatory information instrument.	See **RIN.01 - RIN response**
6.5.6(b)(2)	Our forecast opex must be for expenditure that is properly allocated to *standard control services* in accordance with the principles and policies set out Ausgrid's *Cost Allocation Method*.	See **Section 1 - Executive summary** above
6.5.6(b)(3)	Our forecast opex must include both the total of the forecast opex for the 2024-29 period and the forecast opex for each regulatory year of the 2024-29 period.	See **Section 4** above (**Figure 2.2**)
Opex criteria		

NER clause	Description of requirement (and related RIN requirements where applicable)	How we satisfy requirement
6.5.6(c)(1)	Requires the AER to accept our forecast of required opex if the AER is satisfied that the total forecast opex for the 2024-29 period reasonably reflects each of the opex criteria in clause 6.5.6(c) (**opex criteria**). **Note:** Reset RIN 4.6.1(a)(ii) requires Ausgrid to provide justification for our total forecast opex, including how Ausgrid's total forecast opex reasonably reflects each of opex criteria.	We consider the total forecast opex proposed for the 2024-29 period as outlined in our proposal and this attachment reasonably reflects each of the opex criteria **Section 8.2** below describes how our total forecast opex achieves each of the opex criteria.
Opex factors		
6.5.6(e)	Provides that in deciding whether or not the AER is satisfied our forecast opex satisfies the opex criteria, the AER must have regard to the opex factors in clause 6.5.6(e) (**opex factors**). **Note:** Reset Rin 4.6.1(a)(iii) requires Ausgrid to provide justification for our total forecast opex, including how Ausgrid's total forecast opex accounts for the opex factors.	We consider the total forecast opex proposed for the 2024-29 period as outlined in our proposal and this attachment accounts for the opex factors. **Section 8.2** describes how our total forecast opex accounts for each of the opex factors.

8.1 Achieving the opex objectives

To achieve each of the opex objectives, we must have the necessary capabilities, personnel and systems to undertake the activities necessary to achieve these objectives. For example, one of the opex objectives is to maintain the safety of the distribution system through the supply of standard control services. To achieve this objective, we must have the capabilities, personnel and systems to undertake maintenance on the electrical network. Consequently, in undertaking these activities and in operating the necessary systems, we must incur maintenance opex.

Our total forecast opex therefore comprises the costs of undertaking all the related activities and operating the necessary systems to deliver each of the opex objectives. Our opex forecast for the 2024-29 regulatory period is grouped into three broad cost groups to illustrate how activities in each cost component contribute to the achievement of the opex expenditure objectives.

Figure 8.2 Description of activities, by opex cost group

Opex cost group	Activities and relevance to opex objectives
1. Maintenance opex	Maintenance opex is required to undertake various activities on our electricity network to ensure compliance with regulatory obligations and to maintain system safety, security, reliability and quality of supply. Therefore, these activities and associated costs are critical for achieving all the opex expenditure objectives.
2. Operation and support	Operation expenditure covers those costs incurred in undertaking the required activities to directly support the operation of our network. Support expenditure is necessary for the normal operation of Ausgrid as a business and includes management/governance costs, financial/operational/compliance reporting, customer service and human resource management costs. Also included in support costs are ICT support and property costs. These costs would be found in any typical business. These costs are essential in the effective running and operation of the network and are therefore required to achieve all of the opex expenditure objectives.
3. Other	This expenditure relates to demand management related activities which are required to manage demand on our network through various non-network alternatives. Expenditure of this nature is primarily aimed at addressing the opex objective in clause 6.5.6(a)(1).

We have prepared our opex forecast in a manner that complies with the opex objectives specified in the NER. Specifically, we consider that our forecast meets the opex objectives for the following reasons:

- We have adopted a base-step-trend approach to forecasting most opex. We have used our estimated underlying opex for FY23 as the base year, as we consider this is representative of efficient, recurrent opex for the 2019-24 regulatory period;
- As demonstrated in the table below, the nature of the activities that we will undertake through our opex program is targeted at achieving the opex expenditure objectives. These activities are based on practices currently applied in the base year, and will only change in the 2024-29 period to accommodate changes to scope of works from step changes and the trend rate of change;
- We have considered foreseeable new or changed requirements that will affect our operating activities and costs to identify step changes, and have escalated or de-escalated operating expenditure using the AER's rate of change methodology;
- We have examined the proposed base year costs incurred in meeting our current service level and regulatory obligations and assessed the sufficiency of our ongoing compliance with safety, regulatory and other compliance obligations to identify step changes for corrective actions; and
- We have robust plans, policies, procedures, governance frameworks, and strategies in place to support the delivery of our opex program, and have the requisite capability to deliver the opex program by acquiring and deploying the necessary labour and materials.

Figure 8.3 Summary of our compliance with the opex objectives

NER clause	Opex objective	Why our total opex forecast is required to achieve this objective
6.5.6(a)(1)	Meet or manage the expected demand for standard control services	We have trended our proposed base year opex to account for expected changes in output growth drivers such as customer numbers, peak demand and circuit length (see **Chapter 6** of our **Regulatory Proposal** and **Section 7** above).
6.5.6(a)(2)	Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services	We have assessed our current compliance obligations (and associated base year costs), as well as identifying additional new obligations that we expected to be in place over 2024-29 period. See **Chapter 6** of our **Regulatory Proposal** and **Section 6** above for our proposed step changes for further details on how our proposed opex program allows us to comply with our applicable legislative and regulatory obligations.
6.5.6(a)(3)	Maintain the quality, reliability and security of supply of standard control services	We have proactively sought to engage with our consumers to understand the level of service they value (see **Chapter 3** of our **Regulatory Proposal**) to assist in the preparation of our opex expenditure program (see **Chapter 6** of our **Regulatory Proposal** and **Section 2.2** above). The forecast opex was developed to meet customer preferences and requirements for reliability, safety and security. The opex forecast does not include planned programs to improve service target performance incentive scheme (**STPIS**) performance for the purpose of S6.1.2(4) of the NER.
6.5.6(a)(4)	Maintain the safety and security of the distribution system through the supply of standard control services	

8.2 Meeting the opex criteria and opex factors

The AER is required to decide whether to accept or reject our total forecast opex. The AER must accept Ausgrid's forecast or required opex if it is satisfied that the total forecast opex reasonably reflects each of the operating expenditure criteria (opex criteria), being:

1. The efficient costs of achieving the opex objectives;
2. The costs that a prudent operator would require to achieve the opex objectives; and
3. A realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

In determining whether a forecast meets the opex criteria, the AER must have regard to the opex factors in clause 6.5.6(e) of the NER. This is because the opex factors are intended to represent factors that should be employed in developing a prudent and efficient expenditure forecast, and provide an indication as to whether the resulting forecast expenditure (from applying a prudent forecasting approach) reasonably reflects efficient costs. Consequently, consideration of the opex factors is intended to give the AER confidence that the proposed opex forecast reasonably reflects the efficient and prudent costs required to achieve the expenditure objectives, based on a realistic expectation of demand forecast and cost of inputs.

We have prepared our opex forecast in a manner that is both consistent with, and gives effect to, the opex criteria and factors set out in clauses 6.5.6(c) and 6.5.6(e) of the NER, respectively. This is demonstrated through:

- Our adoption of forecasting approaches consistent with the AER's Better Regulation Handbook, such as our estimated underlying opex for FY23 as the base year in our base-step-trend approach to forecasting opex;
- The development of demand forecasts based on good industry practice which have been independently reviewed (see **Section 7.2**);
- Our consideration of opex/capex substitution possibilities (e.g. step changes reflecting capex/opex trade-offs);
- Our incorporation of customer and stakeholder expectations to reduce opex whilst maintaining current service standards;
- Our provision of actual and forecast opex during the current and past regulatory periods, and explanation for any variances between our actual performance relative to our allowance (see **Sections 2.1** and **3**); and
- Our consideration of industry benchmarking (see **Section 5.2**).

Figure 8.4 below provides a summary of how our opex forecasts accounts for each of the opex factors.

Figure 8.4 Summary of how our total forecast opex accounts for the opex factors

NER clause	Opex factor to account for	How our opex forecast accounts for this opex factor
6.5.6(e)(1) - (3)	Deleted	Not applicable
6.5.6(e)(4)	The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark opex that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period.	We have carefully reviewed the AER's most recent annual benchmarking report and other relevant measures of benchmark opex that would be incurred by an efficient DNSP. We have addressed our relative performance in the AER's 2022 Annual Benchmarking Report in **Section 5.2** above.
6.5.6(e)(5)	The actual and expected opex of the Distribution Network Service Provider during any preceding regulatory control periods	**Chapter 6** of our **Regulatory Proposal** and **Sections 2.1** and **3** above detail our actual and estimated opex for the 2019-24 regulatory period and explain the key reasons for material variances between Ausgrid's actual and estimated expenditure during the current period from the AER's allowance.
6.5.6(e)(5A)	The extent to which the opex forecasts includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	We have proactively engaged with our customers to understand their concerns. **Chapter 3** of our **Regulatory Proposal**, **Attachment 3.1 – Engagement Overview** sets out our engagement approach and our key findings from our customer engagement activities. **Chapter 6** of our **Regulatory Proposal**, and **Sections 2.2** and **6** above explain how we have responded to customer feedback in developing this proposal.
6.5.6(e)(6)	The relative prices of operating and capital inputs	We have sought to assess all feasible options when addressing a need including opex and capex solutions. When doing so, we have used best practice methods for deriving the relative cost of opex and capex solutions, and have applied a common method for real cost escalation. We have applied appropriate

NER clause	Opex factor to account for	How our opex forecast accounts for this opex factor
		escalators to the relative prices of inputs in our opex and capex forecasts (see **Chapters 5** and **6** of our **Regulatory Proposal**, **Section 7** above and **Attachment RIN.05 – BIS Oxford Economics – Cost Escalation Report) for further details**.
6.5.6(e)(7)	The substitution possibilities between operating and capital expenditure	We have considered the substitution possibilities between opex and capex in developing our forecast opex. A key step in our capital investment planning process is to consider a full range of alternative options, including whether there may be an opex solution that is more efficient in addressing the investment need. In addition, we have considered the consequential impact on forecast opex from capex investment interactions, including in relation to certain step changes. See **Section 6** above.
6.5.6(e)(8)	Whether the opex forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4	The regulatory framework, coupled with our commercial focus and customers' expectations, provide strong incentives for Ausgrid to act prudently and efficiently when assessing our expenditure needs for the forthcoming regulatory period. The significant incentive schemes that our opex forecast considers include: • EBSS – this scheme will provide us with additional and consistent incentives to continuously reduce our operating costs to deliver lower prices for our customers. • STPIS – this scheme will help us maintain and improve our service performance and ultimately deliver better outcomes for customers. • Customer Service Incentive Scheme (**CSIS**) – this scheme will help us maintain and improve our performance in areas of service that our customers have told us they most value improvement in. • Demand Management Incentive Scheme and Innovation Allowance – together, these schemes will provide benefits to our customers by reducing network costs over time and thereby lowering prices in future regulatory periods.
6.5.6(e)(9)	The extent the opex forecast is referable to arrangement with a person other than the Distribution Network Service Provider that, in the	There will be some opex attributable to a related party (PlusES Partnership) as they provide certain metering related standard control

NER clause	Opex factor to account for	How our opex forecast accounts for this opex factor
	opinion of the AER, do not reflect arm's length terms.	services to Ausgrid. The commercial terms and prices for these services are considered to be commercial arm's length terms.
6.5.6(e)(9A)	Whether the opex forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b)	Our proposed opex does not include an amount relating to a project that should be more appropriately included as a contingent project under clause 6.6A1(b).
6.5.6(e)(10)	The extent the Distribution Network Service Provider has considered and made provision for, efficient and prudent non-network options	We have considered all feasible options to address network needs, and have selected the most efficient option. Ausgrid has well defined demand management strategies and processes (see Section 8 of Ausgrid's RIN Schedule 1 response), and a track record of implementing demand management initiatives. We have also proposed that the Demand Management Incentive Scheme (**DMIS**) and Demand Management Innovation Allowance (**DMIA**) apply to Ausgrid.
6.5.6(e)(11)	Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s)	N/A – Ausgrid has not published any final project assessments under the regulatory investment test for distribution (**RIT-D**) that are relevant to our proposed opex.
6.5.6(e)(12)	Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor	N/A – This factor is relevant for submission of a revised regulatory proposal and not this initial regulatory proposal.

8.3 Fixed and variable opex activities

The NER require us to identify, for each category of expenditure, to what extent that forecast expenditure is based on costs that are fixed and to what extent it is based on costs that are variable.[35] The length of time applicable to define a cost as fixed or variable is not specified, however 2024-29 period would be considered short run in economics terms. During this period, we will incur both:

- Variable costs, which change as our outputs (customer numbers, circuit length and ratcheted maximum demand) change; and
- Fixed costs, which are incurred regardless of movements in our outputs.

Figure 8.5 below shows those operating activities for which our costs may broadly be considered as either variable or largely fixed. We do not hold information to identify specific fixed and variable costs for each of our opex categories.

[35] NER clause S6.1.2(iii) requires Ausgrid to identify to what extent the forecast expenditure is on costs that are fixed and to what extent it is on costs that are variable.

Figure 8.5 Fixed and variable operating activities

Category	Nature of costs	Example of opex activities
Vegetation management	Fixed	• Identifying, scoping and undertaking proactive vegetation cutting to maintain clearances from electrical assets.
	Variable	• Costs are mostly fixed, however grow incrementally with the size of the network
Maintenance	Fixed	• N/A
	Variable	• Inspection, testing and condition monitoring; and • Corrective repairs.
Emergency response	Fixed	• N/A
	Variable	• Fault and emergency repairs; • Repairs due to nature induced breakdowns; and • Repairs due to damage by a third party.
Non-network	Fixed	• ICT including replacement and maintenance of hardware and licence costs; • Property costs for network assets including rates, taxes, utilities; and • Property costs for non-network assets
	Variable	Maintenance and operation of: • Vehicles; and • Plant and equipment.
Network overheads	Fixed	• Network planning; • System control; • Operator standards and training; • Operational technology; • Asset data and systems; • Customer contact centre; and • Network billing
	Variable	• N/A
Corporate overheads	Fixed	Corporate support functions such as: • Finance; • Human resources management; • Regulation and strategy; and • Legal and secretariat.
	Variable	• N/A

Note: Classification of 'fixed costs' does not mean that these costs will not escalate over a given period. For example, a fixed activity may involve a number of staff. While the staff count may be fixed regardless of output growth, we would reasonably expect to incur cost growth due to wages growth for those staff.