Planning for the future

Essential Energy 2024–29 Revised Regulatory Proposal

November 2023

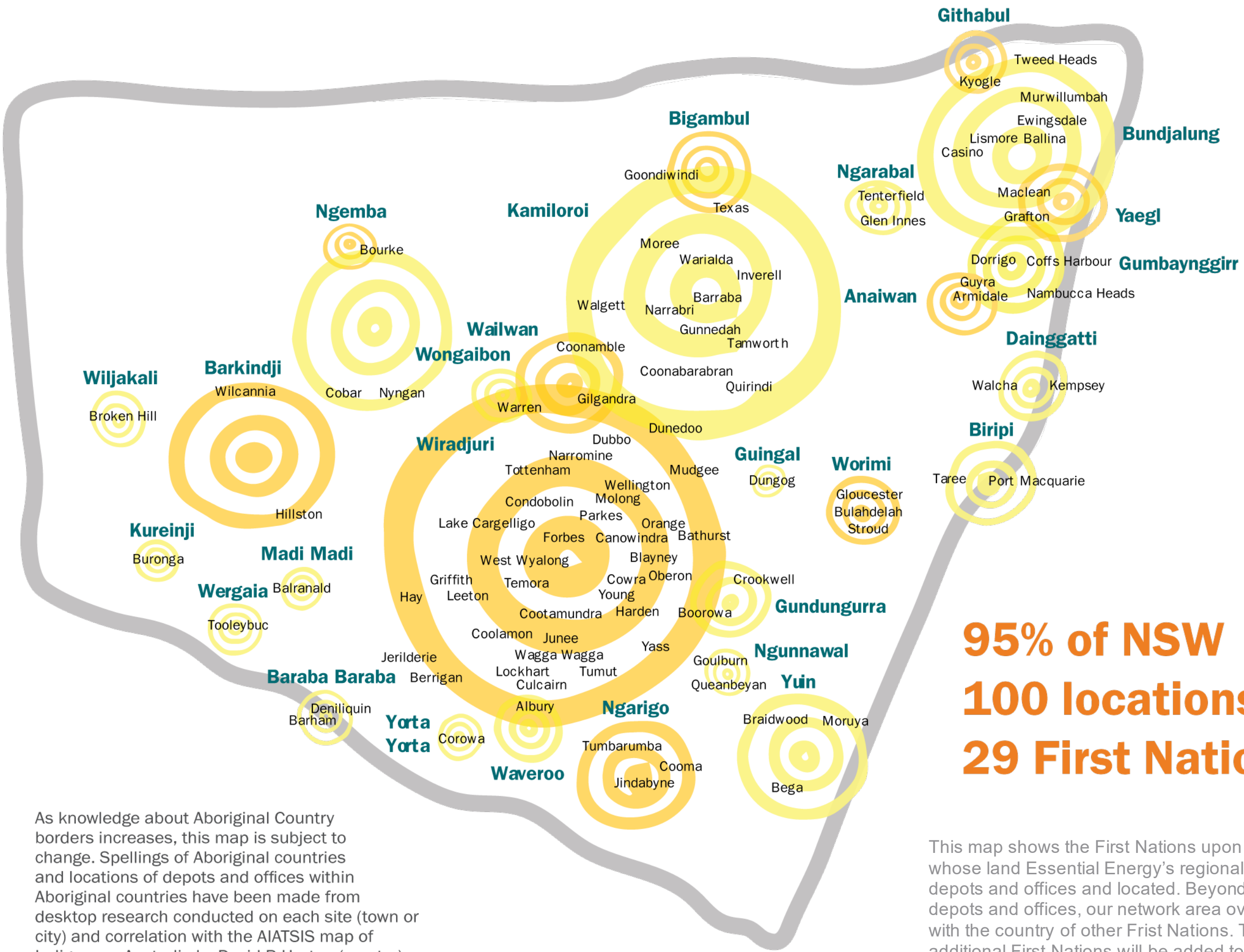
Acknowledgement of Country

Our depots and offices across regional New South Wales are located on the Country of 29 First Nations – from Wiljakali Country on the plains of Far Western New South Wales (NSW), to Ngarigo Country in the high Snowy Mountains and Bundjalung Country on the sub-tropical North Coast, and more First Nations across the diverse landscape that is regional, rural and remote NSW and parts of southern Queensland.

We acknowledge the Traditional Custodians of the lands on which our company is located and where we conduct our business, and we acknowledge all Aboriginal and Torres Strait Islander peoples across Australia. We pay our respects to ancestors and Elders, past, present and emerging.

We are committed to honouring Aboriginal and Torres Strait Islander peoples' unique cultural and spiritual relationships to the land, waters and seas and their rich contribution to society.

Our network area



As knowledge about Aboriginal Country borders increases, this map is subject to change. Spellings of Aboriginal countries and locations of depots and offices within Aboriginal countries have been made from desktop research conducted on each site (town or city) and correlation with the AIATSIS map of Indigenous Australia by David R Horton (creator), © Aboriginal Studies Press, AIATSIS, and Auslig/Sinclair, Knight, Merz, 1996. This is an estimate only based on desktop research and the AIATSIS map.

95% of NSW
100 locations
29 First Nations

This map shows the First Nations upon whose land Essential Energy's regional NSW depots and offices and located. Beyond our depots and offices, our network area overlaps with the country of other Frist Nations. These additional First Nations will be added to the map in our second Reconciliation Action Plan which is currently being developed.

Contents

01

Overview

Chapter summary

- We prepared this Revised Proposal in response to the AER’s Draft Decision.
- We have largely accepted the AER’s Draft Decision.
- Any points of difference have been informed with input from customers and stakeholders.

A message from Essential Energy's Chair and Chief Executive Officer

Doug Halley
Chair

John Cleland
Chief Executive Officer

This document has been prepared in response to the Australian Energy Regulator's (AER's) Draft Decision on our five-year plan for operating and maintaining NSW's largest electricity distribution network from 1 July 2024 to 30 June 2029 (2024–29). It is comprised of a Revised Regulatory Proposal (Revised Proposal) and a Revised Tariff Structure Statement (Revised TSS).

Listening to our customers is at the heart of everything we do as we work to empower communities to use and share energy to make life better today and tomorrow.

After extensive consultation with customers and stakeholders, in January 2023 we submitted our plans for 2024–29. They were reviewed by the AER, which also took on board community feedback, before they issued a Draft Decision on 28 September 2023.

The AER largely accepted our proposed expenditure, although a significant deduction has been applied to reflect a higher penalty for overspending against the operating expenditure allowance over the last five years.

Customers made it clear that they wanted and needed a safe, reliable and affordable network. One that is both resilient and flexible enough to accommodate new and emerging technologies, with pricing structures that keep pace with the changing energy market – particularly the increasing volume of consumer energy resources (CER) connected to and exporting into the network.

This Revised Proposal and Revised TSS reflect the views of our customers and what they want Essential Energy to focus on.

NEXT STEPS

Our customers' views helped shape our Revised Proposal and Revised TSS – and we're always here to listen.

We invite you to read this information and the full documents, and provide your feedback to the AER by 19 January 2024 via the AER's website.

You can also contact us directly at:

Email: yoursay@essentialenergy.com.au

Post: Head of Regulatory Affairs
Essential Energy
PO Box 5730
Port Macquarie NSW 2444

Phone: 13 23 91

Web: https://engage.essentialenergy.com.au/hub-page/eeyoursay

Essential Engagement forum: engage.essentialenergy.com.au

Thank you

Doug Halley
Chair

John Cleland
Chief Executive Officer

Overview

Essential Energy has engaged extensively with customers and stakeholders to develop our initial Regulatory Proposal (Proposal) for 2024–29, which we submitted to the Australian Energy Regulator (AER) in January 2023. We continued to consult with our customers and stakeholders throughout 2023 to inform our Revised Regulatory Proposal (Revised Proposal) and Revised Tariff Structure Statement (Revised TSS) for the AER. This was in response to the AER's Draft Decision, which it published on 28 September 2023.

Our Revised Proposal and Revised TSS should be read in conjunction with our January 2023 Proposal and the AER's Draft Decision. The AER largely accepted our Proposal, but put forward some changes and recommendations for our Revised Proposal.

This Revised Proposal will enable us to provide the safe and reliable network, and affordable services that our customers expect. It will also support a network that is resilient and flexible enough to accommodate new and emerging technologies. It includes pricing structures that keep pace with the changing energy market – particularly the increasing volume of consumer energy resources (CER) connected to and exporting into the network.

Table 1 sets out key elements of our Revised Proposal, compared to the Proposal submitted in January 2023, and the AER's Draft Decision. See **Chapters 7 and 8** for expenditure, **Chapter 3** for revenue and **Chapter 9** for pricing.

Table 1: Key elements of our Revised Proposal

Standard control	Expenditure ($m, 2023–24)		Revenue ($m, nominal)			Average annual price increase from 2024–25 before inflation
	Capital expenditure	Operating expenditure	Rate of return	Opening regulatory asset base	Maximum allowed revenue (smoothed)	
Regulatory Proposal (January 2023)	$2,655	$2,324	5.65%	$10,275	$6,381	2.97%
Draft Decision (September 2023)	$2,655	$2,324	5.83%	$10,265	$6,191	1.65%
Revised Proposal (November 2023)	$2,655	$2,323	5.83%	$10,337	$6,193	1.01%
Revised Proposal including metering	$2,671	$2,478	5.83%	$10,418	$6,482	1.55%

Notes – The values for Essential Energy's January 2023 Proposal reflect equivalent updated values due to changes in inflation and the weighted average cost of capital (WACC). The values for expenditure and allowed revenue relate to the full five-year period. The rate of return is for 2024–25 only. Capital expenditure is net of disposals and capital contributions, and operating expenditure includes debt-raising costs. We have calculated an equivalent average annual price increase for the AER's Draft Decision over the period 2024–25 to 2028–29. The AER's Draft Decision set an average annual increase of 1.0 per cent for 2024–25 and 2025–26, and 2.66 per cent for 2026–27 to 2028–29.

The AER's Draft Decision

The AER largely accepted Essential Energy's proposed operating expenditure (opex) and capital expenditure (capex) for standard control services. The main difference between our January 2023 Proposal and the AER's Draft Decision is in the AER's application of the Efficiency Benefit Sharing Scheme (EBSS)[1] penalty. The AER decided to apply the penalty in full, which impacts the amount of revenue we can recover over the next five years. While we have adopted this decision for the Revised Proposal, we consider that it has been overestimated and suggest an alternative approach that better aligns with the regulatory precedent and the intent of the incentive regime. We believe that in Essential Energy's

[1] The EBSS is an incentive scheme that promotes ongoing reductions in opex. It is based on the incremental year on year underspend or overspend compared to the approved allowance. The value for each year is carried forward for five years. It is then shared with customers in the form of a calculated reward or penalty being added into revenue adjustments for the next regulatory period.

situation, it results in conflicting economic signals that we should not have been as ambitious with our plans for cost savings in 2019–24, and that responding to unforeseen incidents was a 'loss of efficiency'. The penalty compounds the additional costs of external events such as the multiple natural disasters that our business has absorbed over that time.

Our Revised Proposal

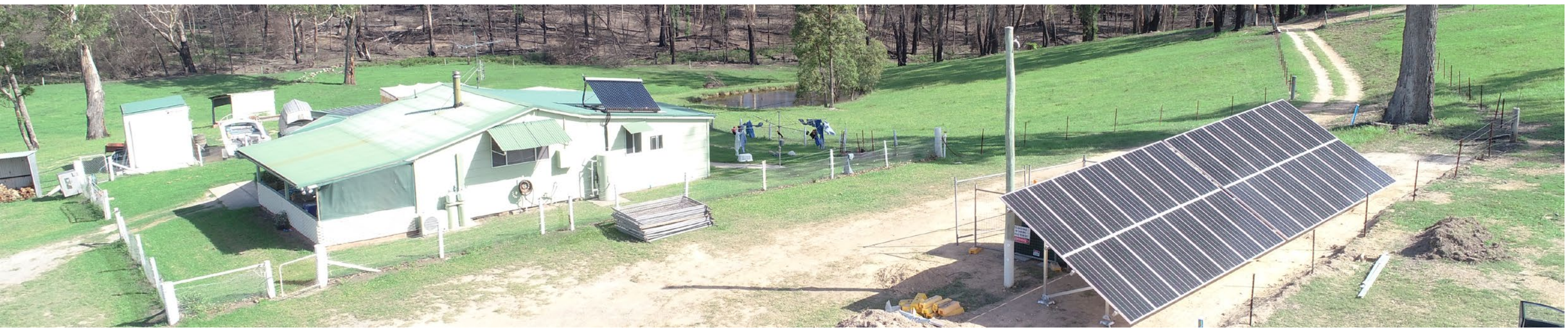
Accepting the AER's Draft Decision for standard control services, our Revised Proposal includes adjustments for actual and forecast expenditures through to 2023–24, and moves legacy metering into standard control services (SCS). (see 'Metering' below).

Our Revised Proposal builds on the AER's Draft Decision by:

- reflecting updated base-year information for 2022–23 and estimates for 2023–24
- addressing those areas of our Proposal that were not fully supported by the AER
- providing information on issues that we suggest the AER consider before it makes its Final Decision in April 2024.

Updated audited actual data from 2022–23 and forecasts for 2023–24 have resulted in a slightly lower level of opex and a higher level of capex than we had previously forecast and which was reflected in the AER's Draft Decision. These updates have changed the forecast opening regulatory asset base (higher) and the outcomes for the opex and capex incentive schemes (lower and higher penalties, respectively) that were used in the Draft Decision. The changes in the revenue building blocks compared against the updated value of network charges for 2023–24, result in a lower forecast increase in real network charges for 2024–29.

In **Chapter 4**, we have provided further detail about our program for stand-alone power systems (SAPS), as requested by the AER. For completeness, we have also included additional information on particular expenditure programs that the AER's technical consultants had queried. Revised bushfire risk modelling means that the risk classification for some areas of our network will be upgraded to high risk – leading to significant increases in vegetation management requirements. We need to work through the optimal solutions to mitigate the risks, which will also involve engaging with affected communities. We understand that many of our customers have been greatly affected by bushfires and will welcome increased vegetation clearance around network assets. Conversely, we appreciate the need for environmental conservation. Rather than proposing a step change in our Revised Proposal for the anticipated increased costs of clearing vegetation (as flagged in our response to the AER's Issues Paper[2]), we have nominated a new type of pass through event (PTE), as described in **Chapter 6**. We consider this to be the most reasonable method to recover uncertain costs of a known event while still permitting the AER to assess those expenditure plans for prudency and efficiency once they are fully developed.



Tariff Structure Statement

The AER's Draft Decision accepted most elements of our TSS. Reflecting the AER's recommendations and information gained from further engagement, our Revised TSS includes modified tariff structures for:

- the Sun Soaker default tariff – we have simplified some aspects of the export price, which will apply to new smart meters from July 2024, although the export charge and rebate components will not commence until July 2025
- batteries located at the high-voltage level – we removed the rebate for these customers exporting into the grid as it was not necessary to signal a change at that level
- individually calculated tariffs – we provided additional information on how we calculate them.

Following the methodology in the AER's guidance, we have also included a legacy metering component in SCS.

Refer to **Chapter 9** for more details, as well as **Attachments 9.01 and 9.02** for our Revised TSS and Revised Tariff Structure Explanatory Statement (Revised TSES).

[2] AER, Issues Paper – Essential Energy Electricity Distribution Determination 1 July 2024 to 30 June 2029, May 2023. Link

Metering

The Australian Energy Market Commission's (AEMC's) review of metering[3] recommends a faster rollout of smart meters. In response, the AER's Draft Decision accelerates the depreciation of the legacy meter asset base by 2029, with the expectation that 100 per cent of legacy meters will be replaced with smart meters by 2030. Our metering costs over the next five years include extra remediation costs for some sites to enable smart meters to be installed. They also include project costs associated with developing and implementing Legacy Meter Retirement Plans (LMRPs) for the smart meter rollout, offset by reduced inspection and testing costs over the period – see **Chapter 11**.

Our Revised Proposal further incorporates metering into the SCS category, to share the resulting increase in legacy meter costs across more customers. We did this after consulting with our customers and stakeholders, who supported this as the fairest solution over this regulatory period, as all customers will ultimately benefit from lower network costs arising from a faster and more comprehensive rollout of smart meters. The outcomes of the AEMC's review are also based on the wider net societal benefits of a faster smart meter rollout. The AER supports this approach. To enable this we have also proposed changes to the Classification of Services for 2024–29, as described in **Chapter 6**.

Public lighting

The AER's Draft Decision made significant top-down cuts to proposed prices for public lighting and recommended that we engage further with stakeholders. Over the past months, Essential Energy has engaged extensively with local councils and their representatives on all elements of our public lighting proposal, but we did not reach a position that was acceptable to all parties. Our Revised Proposal offers further reductions from our January 2023 Proposal and these are described in **Chapter 10**. We consider that this position provides price reductions that are more aligned with stakeholder expectations.

Ancillary network services

Essential Energy has accepted most points in the AER's Draft Decision relating to ancillary network services (ANS), including changing from a fee-based service for minor capital works to a quoted service, excluding special meter tests. In **Chapter 10**, we have included minor adjustments for actual FY24 escalators and forecast inflation as used for standard control, and updated some material fee-based services for material overheads (as accepted in the current regulatory period). We also changed some service fees for new types of security lights (and tariff contract changes), replaced access permit fees with connection fees, and proposed a new quoted fee service for data requests.

[3] AEMC, Final Report – Review of the Regulatory Framework for Metering Services, August 2023. Link

Engagement

Figure 1: Phase 5, February to November 2023

- 9 SCC meetings
- 5 PCC meetings
- 4 CAG meetings
- Public lighting 2 forums 9 meetings
- 1 Large, peaky load Customer Working Group meeting
- 1 Customer webinar
- 1 Customer survey
- 2 Essential People's Panel sessions
- 22 Retailer meetings
- 1 New Technology Provider Forum
- 1 Joint Network Workshop

During 2023, we undertook over 111 hours of formal engagement across multiple topics and channels. This is a summary of this engagement.

Since submitting our Proposal in January 2023, we have focused on responding to feedback raised by our customers and stakeholders, refining parts of our Proposal that we identified as needing further work, and considering the AER's Issues Paper and Draft Decision. In **Chapter 2**, we describe how we have continued to engage regularly with our stakeholder reference groups (the Stakeholder Collaboration Collective (SCC), Pricing Collaboration Collective (PCC), and the Customer Advocacy Group (CAG)) and established our new customer advisory group, the Essential People's Panel. The final Customer Service Incentive Scheme (CSIS) drew on these sources (see **Chapter 6**).

Recognising that economic conditions have changed since our 2022 customer forums, we retested customer support and willingness to pay for building our resilience and for future network investments. In October 2023, we engaged with more than 250 customers via a webinar to update them on changes to the Proposal and the resulting impacts on bills. In a survey following the webinar, 96 per cent of respondents voted in support of these investments. Our customers' priorities and their vision for our network underpin this Revised Proposal.

Future challenges

In **Chapter 5**, we lay out our complex operating environment – including several issues that could change our costs over the next five years. Some of these costs are 'known unknowns', such as the impact of bushfire risk reclassification (discussed above). Others are 'unknown unknowns', such as natural disasters and external regulatory or legislative changes. The pace of change and the impact of the energy transition on our business mean the existing, stable regulatory frameworks are likely to come further under pressure. To that end, we have included minor adjustments in the classification of services for 2024–29, to accompany the amendments required to move metering from alternative control to standard control.

We urge our regulators (including the AER) to focus on improving the agility of regulatory frameworks and reducing red tape to ensure the system can handle the degree of modifications needed and the variety of change agents expected during 2024–29. In **Chapter 6**, we have included changes to the Classification of Services, which will facilitate this to some extent. In particular, we recommend that the AER streamlines the process that enables the recovery of reasonable, prudent and efficient costs that have not been included in regulatory determinations.

Appendix A provides a summary of our responses in our Revised Proposal.

02

Our customer engagement

Chapter summary

- Our engagement program
- Engagement outcomes
- Future engagement

Our engagement program

We undertook Phase 5 of our engagement program to inform our Revised Proposal. This work began after we submitted our initial Proposal in January 2023. Phase 5 included:

- working through customer and stakeholder feedback on our Proposal
- refining areas of our Proposal that we identified needed further work
- considering feedback in the AER's Issues Paper and Draft Decision.

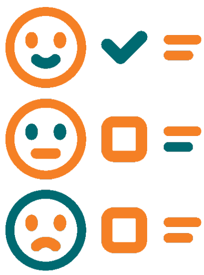
Given the success of Phases 1 to 4 of our engagement program, which provided key information for the development of our Proposal, we used a similar structure for Phase 5, but with the addition of our new Essential People's Panel, as shown in Figure 2. More information on how engagement informed our Revised Proposal in **Attachment 2.01**. We also continued working with our engagement partners, Woolcott Research & Engagement and their report into this phase is available in **Attachment 2.03**.

Figure 2: Phase 5 Engagement channels

Customer webinar and survey

Since we completed Phase 4 in late 2022, the cost of living has increased for our customers. So, we retested our customers' level of support for our planned investments in resilience and our network of the future.

We invited customers who participated in Phases 1 to 4 of our engagement program to a one-hour online webinar, which took place on 18 October 2023. Following the webinar, customers were asked to complete a short survey to indicate whether they still supported the investments targeting resilience and future network outcomes. A total of 252 customers completed the survey, with 96 per cent indicating their support for these investments.



As such, our Revised Proposal reflects this continued high level of support for these new types of investments, as outlined in more detail in **Chapter 4**.

> *"It is important to look to the future. To do this, I believe that you have to invest. I understand that costs for BAU are increasing, but to progress and move forward and minimise ongoing charges, investing in composite poles, SAPs, education, looking out for the environment etc are all really important and need to be paid for."*
>
> **Survey respondent**

> *"The cost per consumer is quite small when the long-term benefits are considered. It is hard to put a value on the social benefits of the proposed improvements but these will be major."*
>
> **Survey respondent**

Engagement topics

Pricing

We have continued to engage with small and large customers and stakeholders on our pricing structures. Phase 5 engagement occurred through the Essential People's Panel, meetings of the Stakeholder Collaboration Collective (SCC) and Pricing Collaboration Collective (PCC), the New Technology Providers Forum, and retailer and one-on-one meetings. Our **Revised TSS** provides more information on how we responded to feedback.

Metering

Phase 5 engagement included a new focus on metering costs after the release of the AEMC's *Final Report: Review of the Regulatory Framework for Metering Services* and the AER's Draft Decision encouraging engagement with customers about reclassifying legacy metering services as SCS.

After engaging with the Essential People's Panel and the SCC, we decided to apply legacy metering costs as part of SCS. (**Chapter 11** contains more information on this approach.) We shared the estimated average bill impacts of this changed approach at the customer webinar. This engagement raised customer awareness of the acceleration of the smart meter rollout and shared the related bill impacts so that our customers could also consider those extra costs when completing their survey responses.

Customer Service Incentive Scheme

Our Essential People's Panel provided feedback on changes to our Customer Ease metric; how to address this feedback; and how the changes should impact the weightings. We engaged further with the SCC on the methods we used to set the targets for each CSIS measure and shared these targets with customers at the October customer webinar. We agree with the SCC's suggestion that we continue sharing information about progress on our customer service incentive measures with our Essential People's Panel. This will enable us to receive ongoing feedback on our approach during the regulatory period.

This will also help set us up for future regulatory periods. More information on our approach to the CSIS can be found in **Chapter 6**.

Stand-alone power systems

We used our Phase 5 engagement to inform revisions to our Connection Policy relevant to SAPS customers, specifically related to the circumstances where customers should be required to pay for upgrades to their SAPS. Our engagement partner, Woolcott Research & Engagement, conducted in-depth interviews with eight customers we had identified as potential SAPS customers (its report is available in **Attachment 2.04**). These customers supported our approach, which is described in **Chapter 8** and included in **Attachment 8.02**.

Public lighting

In Phase 5, we undertook further engagement with local councils, specifically Southern Lights' project partners, about our public lighting proposal. Between May and August 2023, we held five online meetings and a two-day in-person workshop with 19 councils and two Joint Organisations. Since the release of the AER's Draft Decision, we have also met with representatives from Southern Lights four times. While this Revised Proposal reflects many areas of feedback from our stakeholders, we have been unable to agree on all areas. However, we have delivered significant price reductions compared to current values. Please refer to **Attachments 2.02 and 10.05** and **Chapter 10** for more details about our public lighting engagement.

NSW Electricity Infrastructure Roadmap

Since the January 2023 Proposal, we have engaged with stakeholders and our Essential People's Panel on how to recover costs of the NSW Electricity Infrastructure Roadmap (NSW Roadmap). The NSW Government has legislated that the NSW Consumer Trustee will propose these costs, which the AER will then review and approve independently, and they will be recovered via NSW distribution network charges. Essential Energy will not absorb any of the NSW Roadmap cost recovery – we will pass these funds directly to the NSW Government.

In September, the NSW Government committed to working with NSW networks to align a cost-recovery approach, as recommended in the NSW Government's *Electricity Supply and Reliability Check Up* report. We are working with the NSW Government and other NSW networks on principles for recovering Roadmap costs . Throughout this process, we will advocate for the feedback we received from our customers and stakeholders. We are also awaiting the NSW Government's review of the NSW Roadmap's exemptions framework.

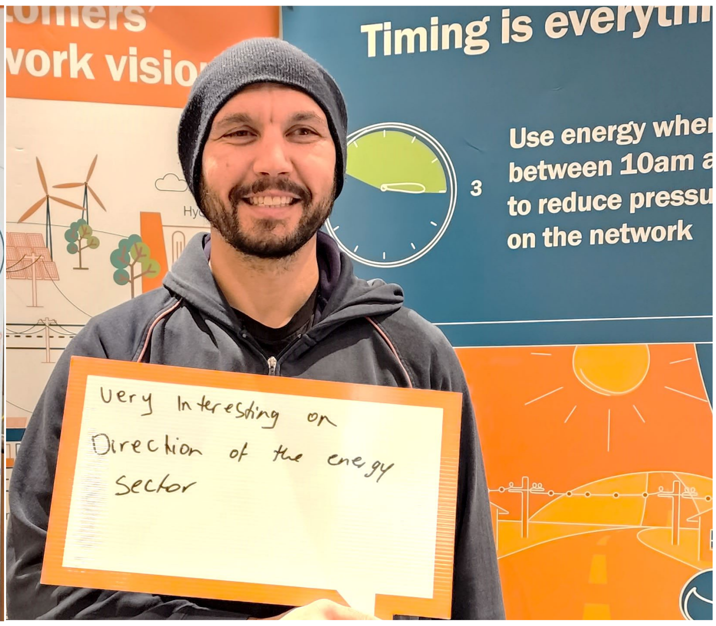
Future engagement

We look forward to hearing from our stakeholders and customers about our Revised Proposal. We encourage any interested parties to make a submission to the AER. We will consider any feedback raised in this process and will continue to engage with the AER to inform its Final Determination. Following the AER's Final Determination, we will share our approved plans for 2024–29 with our customers and stakeholders.

Our engagement to develop our Proposal and this Revised Proposal has been invaluable and has allowed us to focus on what is truly important for our customers. We want this to continue.

We will meet regularly with our Essential People's Panel each year as well as our Customer Advocacy Group, to engage on how we are implementing our 2024–29 plans and report on how we are tracking. This will set us up for developing our plans for the next regulatory period and beyond.

Ongoing customer and stakeholder engagement about our plans is critical for building customer trust and understanding in an environment that is dynamic.



03

Our revenue requirement

Chapter summary

- Our Revised Proposal accepts the AER's Draft Decision on the 2024–29 revenue requirement.
- We have included mechanistic updates to the revenue requirement, and legacy metering services have been placed under standard control services.
- We have included the Draft Decision EBSS penalty, but propose an alternative that better aligns with the intended regulatory incentives.

Our revenue requirement

The revenue requirement shows the total standard control revenue we propose to recover from customers over the 2024–29 regulatory period to provide our electricity distribution SCS (referred to as 'main SCS') and metering SCS.

Our revenue requirement is based on the AER's Draft Decision, which includes its acceptance of the expenditure forecasts and priorities we agreed with customers, but also the imposition of a higher EBSS penalty. While this Revised Proposal reflects the EBSS penalty as applied by the AER, we consider that it has been overestimated. In **Attachment 3.07**, we have outlined an alternative approach to estimating the EBSS that better aligns with regulatory precedent and the intent of the incentive regime.

To support the implementation of the AEMC's recommendation that all customers have smart meters by 2030, we have reclassified legacy metering services, moving them from alternative control services (ACS) to SCS. Consistent with the guidance the AER issued in November 2023, we have produced two annual revenue requirements using separate post-tax revenue models (PTRMs) – one for main SCS and one for legacy metering SCS.[4] These forecasts are provided in Table 2, Table 3, Table 4 and Figure 3, along with the consolidated annual revenue requirement.

In relation to the revenue requirement for main SCS, we have applied mechanistic changes to update the forecast, in addition to accepting the AER's Draft Decision (which also included updated WACC and inflation).

The legacy metering SCS revenue requirement reflects the implementation of the accelerated legacy metering replacement program, so it differs from the forecasts in our January Proposal and the Draft Decision. **Chapter 11** provides information on the development of the forecast revenue requirement for SCS legacy metering services.

The forecast revenue requirement for main SCS, excluding legacy metering services, is $5,693 million (real June 2024).

Table 2: SCS smoothed revenue requirement: Main SCS (excluding legacy metering services)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Proposed annual revenue	1,116	1,127	1,139	1,150	1,162	5,693
Proposed annual real revenue change	-1.01%	-1.01%	-1.01%	-1.01%	-1.01%	

Numbers may not add due to rounding

The forecast revenue requirement for the SCS legacy metering services is $265 million (real June 2024).

Table 3: SCS smoothed revenue requirement: Legacy metering services

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Proposed annual revenue	52	53	53	53	54	265
Proposed annual real revenue change	-56.0%	0.0%	0.0%	0.0%	0.0%	

Numbers may not add due to rounding

Our revenue requirement for the 2024–29 period, including main and legacy metering SCS, is $5,958 million (real June 2024).

Table 4: SCS smoothed revenue requirement: Main and legacy metering services

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Proposed annual revenue	1,168	1,180	1,192	1,203	1,215	5,958
Proposed annual real revenue change*	-1.55%	-1.55%	-1.55%	-1.55%	-1.55%	

* Numbers may not add due to rounding. The annual real revenue change shown is the average annual increase required to recover the net present value of the 2024–29 revenue requirement, which is different to the change in annual revenue from year to year. Shown in Table 2 and Table 3.

[4] AER, Legacy metering services – Guidance note, November 2023 Link

Figure 3 illustrates the actual standard control services revenue received by Essential Energy up until 2022–23 and the forecasts in this Revised Proposal through to 2028–29. Revenue for the 2024–29 regulatory period for main SCS, excluding metering, is virtually the same as for the 2019–24 period (0.05 per cent difference in real terms).

The recovery of legacy metering costs will provide the only increase in real revenue.

Figure 3: SCS smoothed revenue by year

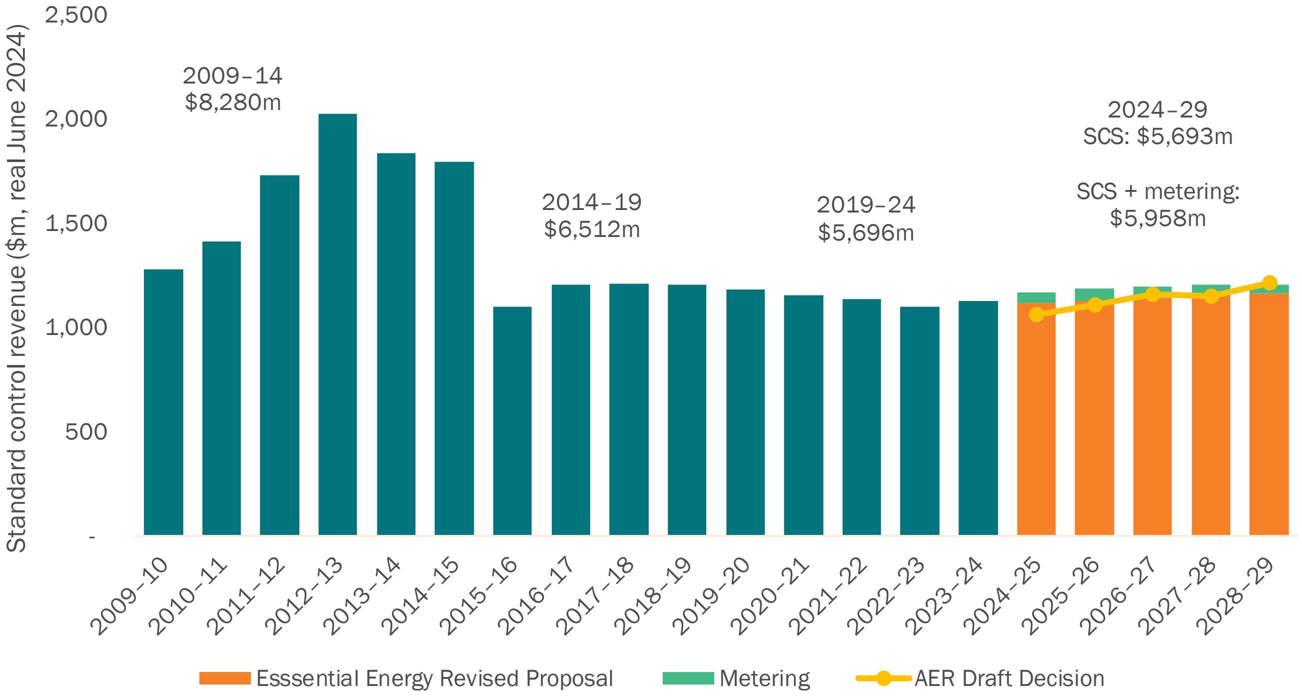
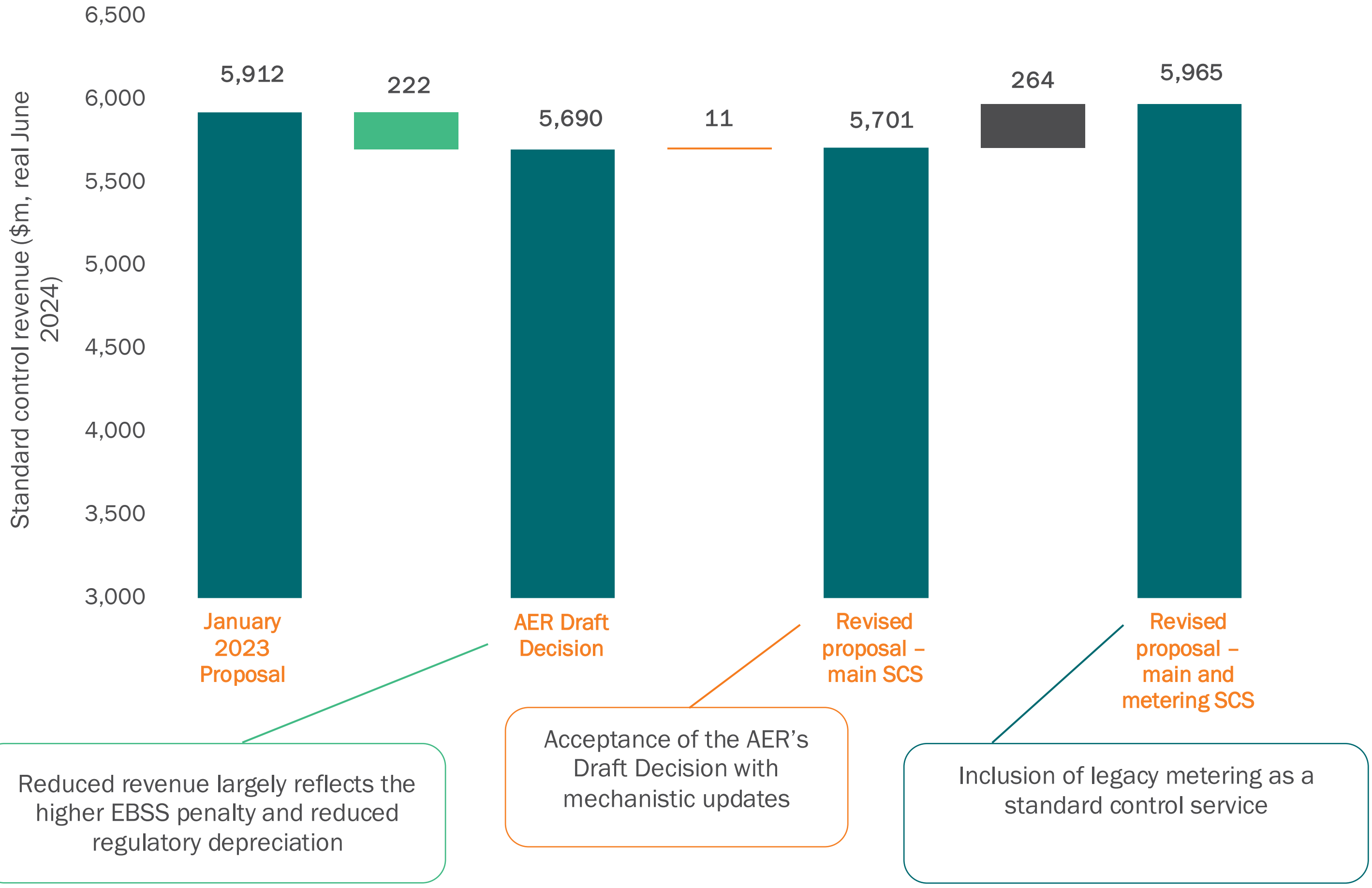


Figure 4 shows the SCS unsmoothed revenue in our January 2023 Proposal, the AER's Draft Decision and this Revised Proposal. Changes to revenue reflected in this Revised Proposal relate to:

- higher inflation and interest rates, which impact our RAB and our cost of funding (these inputs adopt the AER's Draft Decision values)
- reduced regulatory depreciation, due to inflation increasing from 2.5 per cent to 2.8 per cent
- reduced tax allowance, mainly due to lower regulatory depreciation
- increased opex, reflecting updated 2022–23 actual expenditure, a Software as a Service (SaaS) accounting rule base-year adjustment and higher inflation
- reductions due to revenue adjustments and, in particular, the higher EBSS penalty
- inclusion of metering services within SCS.

Figure 4: Change in SCS unsmoothed revenue between January 2023 Proposal and Revised Proposal



The remainder of this chapter provides the revenue components for main SCS. Details of legacy metering SCS revenue components are provided in **Chapter 11**.

Table 5: Main SCS: Building block components for our unsmoothed annual revenue requirement ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Return on capital	586	602	619	635	653	3,096
Return of capital	89	107	123	114	119	552
Operating expenditure	455	460	464	470	473	2,323
Revenue adjustments	-67	-65	-50	-76	-40	-299
Tax allowance (net)	–	2	7	10	10	29
Total proposed unsmoothed revenues	**1,063**	**1,105**	**1,164**	**1,153**	**1,215**	**5,701**

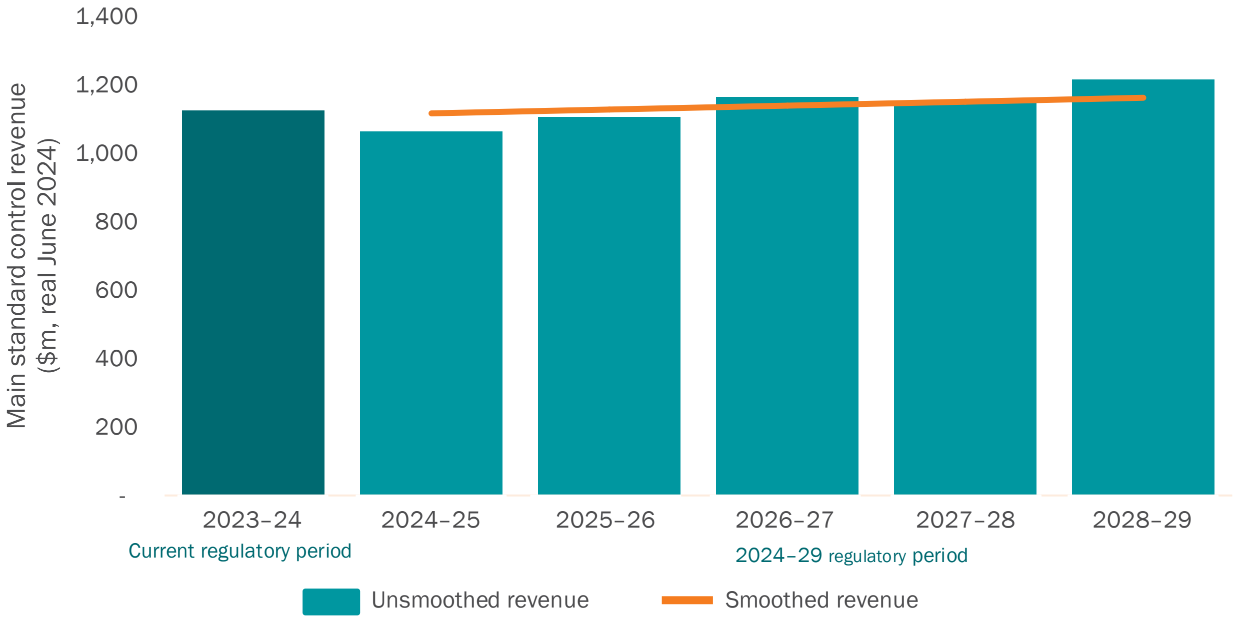
Numbers may not add up due to rounding

To minimise pricing variations caused by fluctuations in our expenditure, we have smoothed our main SCS revenue. The resulting revenue profile has been calculated using the AER's PTRM. This ensures our smoothed revenue for 2024–29 is equal to the unsmoothed revenue in net present value terms for the same period.

Table 6: Main SCS: Smoothed annual revenue requirement ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Proposed smoothed revenue	1,116	1,127	1,139	1,150	1,162	5,693

Figure 5: Main SCS: Smoothed and unsmoothed annual revenue requirement profile



Regulatory asset base

The estimated opening value of our RAB as at 1 July 2024 is $10,337 million (in nominal terms). We have calculated this amount using the AER roll forward model (RFM) and in accordance with the National Electricity Rules (NER). It reflects the roll forward of actual capex for four years (2019–23) and forecast capex for one year (2023–24).

Table 7: Main SCS: Indicative opening regulatory asset base value as at 1 July 2024 ($m, nominal)

$m, nominal	2019–20	2020–21	2021–22	2022–23	2023–24
Opening RAB	8,105	8,450	8,610	9,004	9,843
Add: actual and estimated capex	480	412	444	523	562
Less: regulatory depreciation	-135	-252	-50	316	-14
Less: adjustments for 2018–19 actual capex					-54
Closing RAB	**8,450**	**8,610**	**9,004**	**9,843**	**10,337**

Numbers may not add up due to rounding

Capital expenditure

The capex forecast accepts the AER's Draft Decision. More information about our capex plans for main SCS can be found in **Chapter 8**.

Table 8: Main SCS: Proposed net capital expenditure ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Capex	534	528	531	526	537	2,655

Numbers may not add up due to rounding

Regulatory depreciation

We have applied the AER's preferred approach to calculating regulatory depreciation, as shown in the RFM. The AER's approach applies a weighted average remaining life (WARL) calculation to all existing and forecast new assets in the RAB using the straight-line depreciation methodology. Within the AER's PTRM, the value of regulatory depreciation is calculated as WARL-based straight-line depreciation less the indexation of the RAB value for inflation.

To calculate the RAB indexation values, we used a forecast inflation rate of 2.80 per cent.

Table 9: Main SCS: Proposed regulatory depreciation ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Straight-line depreciation	371	393	413	408	416	2,000
RAB indexation	282	286	290	294	297	1,448
Regulatory depreciation	**89**	**107**	**123**	**114**	**119**	**552**

Regulatory asset base roll forward

To calculate the return on capital building block component, we started with the forecast value of RAB as at 1 July 2024 and rolled it forward each year of the 2024–29 regulatory period using our proposed capex and regulatory depreciation values.

Table 10: Main SCS: Forecast RAB roll forward values for 2024–29 regulatory period ($m, nominal)

$m, nominal	2024–25	2025–26	2026–27	2027–28	2028–29
Opening RAB	10,337	10,803	11,256	11,708	12,177
Add: actual and estimated capex	557	566	586	596	626
Less: regulatory depreciation	-92	-113	-134	-128	-136
Closing RAB	**10,803**	**11,256**	**11,708**	**12,177**	**12,667**

Numbers may not add up due to rounding

Allowed rate of return

The rate of return (or WACC) of 5.83 per cent for 2024–25 reflects the AER's Draft Decision (and the 2022 Rate of Return Instrument). The AER will update this for the final decision.

Table 11: Placeholder allowed rate of return

Rate of return parameters	Year 1 placeholder rates (%)
Cost of equity (nominal post-tax)	7.67
Cost of debt (nominal pre-tax)	4.60
Gearing	60.00
Nominal vanilla WACC estimate	5.83
Gamma	57.00
Inflation	2.80

Debt-raising and equity-raising costs

The process of raising debt finance and equity finance incurs transaction costs that should be recognised in regulated revenue allowances over the 2024–29 regulatory period. We updated our forecasts of debt raising costs using the formula-driven approach in the AER's standardised PTRM. Proposed debt-raising costs are $28 million (real June 2024) for the 2024–29 period.

We propose not having an allowance for equity-raising costs over the 2024–29 regulatory period, in line with the standard calculations performed by the AER's PTRM.

Forecast inflation

We have used the AER's Draft Decision estimate of annual inflation of 2.80 per cent for this Revised Proposal. The AER will update the inflation estimate again for the final decision.

Operating expenditure

Table 12 shows the proposed opex relating to the provision of main SCS. More detail about our opex plans are in **Chapter 7**.

Table 12: Main SCS: Proposed operating expenditure ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Controllable opex	450	455	459	464	467	2,295
Debt-raising costs	5	5	6	6	6	28
Total opex	**455**	**460**	**464**	**470**	**473**	**2,323**

Numbers may not add up due to rounding

Corporate tax

To estimate the cost of corporate tax, we have used the current corporate tax rate of 30 per cent and a value for imputation credits of 57.00 cents per dollar of tax paid. We calculated our estimates using the PTRM.

Table 13: Main SCS: Proposed corporate tax allowance ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Corporate tax	–	2	7	10	10	29

Revenue adjustments

The NER allows Essential Energy to adjust the proposed annual revenue requirement for revenue increments or decrements arising from the impact of:

- incentive schemes that apply during the current regulatory period
- residual under-recovered or over-recovered revenues associated with applying the revenue cap mechanism in the current regulatory period
- using shared assets to provide unregulated services in the 2024–29 regulatory period.

Efficiency Benefit Sharing Scheme

As part of its determination for the 2019–24 regulatory period, the AER applied the EBSS to Essential Energy's opex. We have adopted the AER's Draft Decision on the EBSS penalty but also proposed an alternative that better aligns to intended regulatory incentives. This is explained in **Attachment 3.07**.

Table 14: Main SCS: Proposed Efficiency Benefit Sharing Scheme revenue decrement ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
EBSS penalty	-67	-65	-49	-76	-40	-297

Capital Expenditure Sharing Scheme

As part of its determination for the 2019–24 regulatory period, the AER applied the Capital Expenditure Sharing Scheme (CESS) to Essential Energy's capex. The CESS has been updated in accordance with the AER's Draft Decision.

Table 15: Main SCS: Proposed Capital Expenditure Sharing Scheme revenue increment ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
CESS penalty	-5	-5	-5	-5	-5	-26

Demand Management Innovation Allowance

The AER's Demand Management Innovation Allowance (DMIA) encourages the trial of innovative demand management projects. At this stage, we forecast that we will use the whole DMIA allowance over the 2019–24 regulatory period for our work on tariff trials, network islanding, renewable hosting maximisation and electric vehicle (EV) integration.

During 2024–29, access to this additional allowance will encourage Essential Energy to continue working on understanding and integrating new ways of reducing the costs of electricity supply as well as support the sustainability of the industry. The forecast DMIA included in our revenue calculation is shown in Table 16.

Table 16: Main SCS: Proposed Demand Management Innovation Allowance increment ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
DMIA	1	1	1	1	1	**5**

Proposed shared asset revenue reduction

Shared assets are regulated network assets we use to provide regulated and unregulated services. The AER may reduce Essential Energy's forecast annual revenue requirement in any regulatory year to reflect the forecast costs of using shared assets that are being recovered from unregulated revenues. In making this decision, the AER must have regard to its shared asset principles and guideline.

According to the shared asset guideline, the use of shared assets is material when a distributor's annual unregulated revenue from shared assets is expected to be greater than 1 per cent of its total smoothed revenue requirement in any year of the relevant regulatory period.[5] If the materiality threshold is met, the AER determines cost reductions based on forecast revenues from the unregulated services the distributor is expected to provide. If the materiality threshold is not met, no shared asset cost reduction applies.[6]

We have applied the AER's shared asset guideline and calculated the materiality of our expected use of shared assets to earn unregulated revenue over the 2019–24 regulatory period. The guideline states: "If the total unregulated revenue is expected to be greater than 1 per cent of the regulated revenue, we will apply a cost reduction."

Table 17 indicates that our forecast unregulated revenue from shared assets does not exceed the 1 per cent materiality threshold of our proposed regulated revenue. Therefore, it is not necessary to apply any shared asset cost reduction to our proposed annual revenue requirement for any year in the 2024–29 regulatory period.

Table 17: Main SCS: Materiality of shared asset use ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Proposed annual revenue (smoothed)	1,116	1,127	1,139	1,150	1,162	5,693
Materiality threshold (1%)	11	11	11	11	12	**57**
Forecast unregulated revenue from shared assets	4	4	4	4	4	**21**

[5] AER, Better Regulation, Shared Asset Guideline, November 2013, p. 8 Link

[6] ibid. p. 6.

04

Network of the future and resilience

Chapter summary

- Customers strongly support our proposed new types of investments.
- We include further information on these programs to provide assurance to the AER.

Our Proposal included expenditure to benefit customers in areas experiencing significant change, including on CER integration and network resilience. Our customers strongly endorsed the plans for investing in these themes, which we put forward in our Proposal. Following the release of the AER's Draft Decision, we retested customer support in a new round of engagement – and customers continued to strongly support these new areas of investment.

The AER accepted our proposed overall expenditure (subject to us providing additional information on SAPS). This included expenditure to address the changing needs of customers, particularly for resilience and future networks. However, the AER also gave us feedback on specific programs, and we seek to address those matters below.

Resilience

Lived experience of a number of natural disasters over the 2019–24 regulatory period for both customers and Essential Energy has been a catalyst for change in customer priorities, with climate change and extreme weather events being at the forefront of customers' minds. Expenditure in the Proposal to improve the resilience of our networks and to support our communities was strongly supported by and developed with customers through extensive engagement. Customers provided us with resilience as one of their priorities for 2024–29. We developed a variety of alternative investments that will improve resilience and which had positive risk value outcomes. We see the AER's Draft Decision to accept this expenditure as a positive outcome that matches the expectations of our customers.

In its Draft Decision, the AER made several observations about the programs, including their prudency and efficiency. Essential Energy will take on board this feedback as we undertake these programs over the next five years and into the following 2029–34 regulatory period.

While the 2019–24 regulatory period has been influenced by several large-scale weather events, these are not isolated. Climate-related events in previous periods also had on impact on the network. However, these types of events are likely to occur with increasing frequency and their impacts on the network and our customers are likely to intensify. We will continue to review and improve our modelling to support resilience investments in a conservative manner, but we will also recognise that the challenges being faced are likely to occur over an extended period of time.

With regard to our proactive pole replacement program, the AER queried:

- program overlap
- the extended 60-year net present value period
- benefits being realised instantly.

We are satisfied that any overlap of our proactive pole replacement program with other programs is minor. We have provided our analysis through the early signals pathway and via engagement with the AER and its consultants. A net present value (NPV) period of 60 years was selected as Essential Energy expect the benefits of composite pole replacements will last in excess of 60 years, due to the expected life span of this replacement material. Given the types of assets and the number of pole failures we are currently experiencing due to bushfires, we expect to see immediate benefits from replacing them. Based on this, we do not agree that proactive replacement does not meet the AER's guidance note. This immediate benefit is also reflected in our total reliability outcomes forecast for the 2024–29 period.

Although the AER's Draft Decision supported the telecommunications and microgrids expenditure, the AER observed that it could be classified under augmentation – reliability expenditure. We accept that because we have created the category of 'Resilience expenditure', the classification of and distinction between expenditure categories will require ongoing review and adjustment. We believe this expenditure meets the requirements of the AER's guidance note, and we recognise the immediate reliability benefits of the programs. For this reason, we included reliability benefits in the Service Target Performance Incentive Scheme (STPIS) target reductions for 2024–29. We will, however, review our programs throughout the 2024–29 regulatory period to ensure we are investing in the highest value options for network interventions.

Resilience of the network for those of us living in regional areas is extremely important. This will require investment in the network, which I am prepared to pay for. Further, many of the plans for the future involve new technologies such as microgrids, peer-to-peer trading, community batteries. We must implement these technologies as soon as possible to be part of the sustainable development drive.

Survey participant

Future networks

In the Draft Decision, the AER and its consultants raised concerns that Essential Energy might be overestimating solar curtailment and the associated benefits of alleviation through our proposed investments. While the AER indicated that it would be pragmatic and approve our proposed capex, the feedback suggested that we consider changing the scope and budget.

Quantifying benefits

Concerns about scope and budget stem from a perceived overestimation of curtailment alleviation benefits, and from the static export limit (1.5kW) we identified as the counterfactual to the dynamic operating envelope (DOE) capability.

> The Intrinsic Hosting Capacity analysis shows that a significant proportion of customers on our network (17 per cent) have zero export capacity, and at 1.5kW about 25 per cent of customers would experience overvoltage. Considering these results, and that existing customers (and customers connecting before export limits are lowered or DOEs are introduced) have considerably higher export limits (or no export limits), we believe the identified static export limit gives customers equitable access to the network while requiring minimum investment in pre-constrained network segments.

> Exports above the identified future static limit of 1.5kW are expected to significantly increase costs for the network. These must be justified against the export curtailment alleviation benefits of our investments, in line with the AER's Distributed Energy Resources (DER) Integration Expenditure guidance. In the most constrained parts of the network, customer concentration is low, which results in additional investment providing limited benefits. For equitable customer outcomes and to avoid applying static zero export limits to customers installing solar in the future, we must retain export capacity for future customers (or unlock this capacity using DOEs).

> The Intrinsic Hosting Capacity and the Hosting Capacity analysis used 253V as the overvoltage threshold. The AER's consultant suggested that 258V should be used instead, to align with AS/NZS 4777.2:2020 *Grid connection of energy systems via inverters, Part 2: Inverter requirements*. However, we believe the results remain fit for purpose as:
  - CER technical standard compliance remains low across the National Electricity Market (NEM)
  - the threshold is aligned to AS/NZS 4777.2:2015 (covering most installations on the network)
  - Volt-Watt response is triggered at 253V under AS/NZS 4777.2:2020
  - Curtailment is underestimated in the modelling due to limitations, such as:
    - capturing phase imbalance on the network.
    - not considering curtailment due to Volt-VAr response modes (which start at 240V under AS/NZS 4777.2:2020).

> While the 1.5kW threshold was used to inform the future static export limit, the cost–benefit analysis estimated curtailment due only to static export limits (modelled to apply from 2030). It does not consider any curtailment due to overvoltage (Volt-Watt response, Volt-VAr response or inverter tripping).

Dynamic operating envelope trials and lower network visibility

The AER's consultant indicated that we could reduce expenditure by delaying programs aimed at improving network visibility and DOE capabilities. The capability uplift required to enable basic DOEs has limited flexibility in terms of the required expenditure. Additionally, reduced expenditure would delay the implementation of DOEs and force the lowering of static export limits sooner than currently proposed. We do not agree with the suggested alternative approach of relying on customer complaints to target areas for resolving overvoltage as a way to reduce investment. This would lead to poor customer experience and an increase in reactive complaint management, with the resulting expenditure eroding any gains from reduced investment. A proactive approach has far-reaching benefits, such as enabling efficient network planning, ensuring safety, and providing an efficient export service that meets customer expectations. Network visibility is also a key enabler for the alternate investment areas identified by the AER and its consultants.

Revised Proposal

We believe that the Future Network Business Case and its associated cost–benefit analysis provides a conservative estimate of the benefits of the proposed investments. It is the optimal, efficient and prudent level of expenditure required to deliver cost-effective equitable outcomes to customers across the network.

With the inherent uncertainty of forecasts and modelling limitations, it is appropriate for the AER to take a pragmatic approach in approving the overall revenue requirement. We commit to taking the AER's feedback on board when implementing the Future Network program initiatives over the next five years.

Stand-alone power systems

In their Draft Decision, the AER raised concerns around the efficient pricing of SAPS being deployed within Essential Energy's footprint. Market testing in September 2023 confirmed that the unit rate costings included in our Proposal are reasonable and already assume increasing efficiency over time. The installation of a regulated SAPS requires a higher upfront cost than a customer-owned SAPS. This is due to the need to provide an equivalent level of reliability (and customer protections), as if the customer was still connected to the grid. This was a key objective of the AEMC review into allowing distributors to transition grid-connected customers to SAPS.[7] Following the review, NSW distributor licence conditions were updated to include minimum reliability standards for SAPS, and to permit regulated SAPS customers to claim compensation if reliability does not meet the specified Guaranteed Service Levels (GSLs). Due to our regulatory obligations, the following items are therefore necessarily more conservative than that of a customer-owned or third-party owned SAPS:

- system reliability
- system size
- site security.

In support of the unit costings and how Essential Energy has approached SAPS specifications, further information is provided in **Attachment 4.01**. In addition to supporting materials supplied to the AER, customers support the specification and rollout of the SAPS program. The outcomes of this engagement were provided to our Customer Advocacy Group and the AER.

[7] AEMC, Review of the Regulatory Frameworks for Stand-Alone Power Systems – Priority 1, May 2019 Link

05

Future challenges

Chapter summary

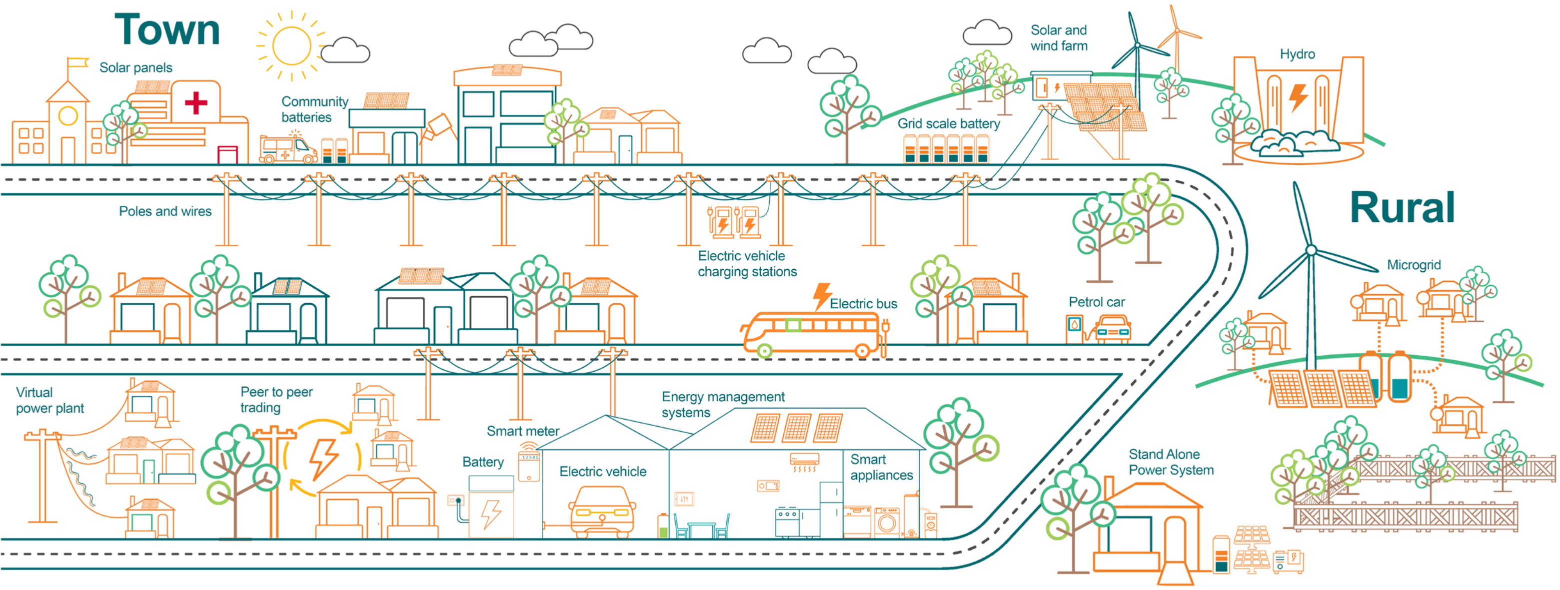
- This chapter highlights the challenges Essential Energy is likely to face over 2024–29 that have not been reflected in our Revised Regulatory Proposal but that may result in additional or unforeseen costs.
- We discuss the need for an agile and flexible regulatory framework and process that facilitates the efficient recovery of unforeseen costs in a simple and effective manner.

As outlined in **Chapter 4**, the electricity industry is going through a period of unprecedented change, which will continue to have major impacts on all industry participants for decades to come. Much of this is driven by the goals of 82 per cent of Australia's energy being sourced from renewable sources by 2030, the Paris Agreement emissions reduction target of a 43 per cent reduction from 2005 levels by 2030, and net zero by 2050. Additionally, the NSW Government introduced legislation to set emissions reduction targets of at least 50 per cent by 2030 and achieving net zero by 2050. Factors such as climate change, new technologies and shifting customer expectations all mean that electricity distributors like Essential Energy have to rethink how they distribute electricity and operate their businesses.

We have prepared our Revised Proposal based on the best information available at the time of writing, aligning to the current regulatory framework and rules. Our expenditure plans reflect the projects and programs that we currently know about and that fit into the existing regulatory framework.

Our Proposal was largely prepared in 2022 and submitted in January 2023, covering the period to June 2029 – a planning horizon of six and a half years. The Revised Proposal planning horizon is slightly less, at five and a half years. Due to the rapidly changing and dynamic environment, it is impossible to predict with 100 per cent certainty the challenges we will face and the projects, programs and resultant expenditure required to deliver a safe, reliable, affordable and compliant electricity distribution service over the next six or seven years.

There are some areas of expenditure that Essential Energy knows about but that have not been included in our Revised Proposal because they either do not fit into the existing regulatory framework or we do not have sufficient details to include them at this point in time (known unknowns).



There will inevitably be other required areas of material expenditure that we are not yet aware of (unknown unknowns) and have therefore not included in our plans.

As such, we request that regulators, including the AER, consider making the regulatory framework and processes more flexible, adaptable and nimble to enable recovery of reasonable, prudent and efficient costs incurred by industry participants over a planning horizon that spans six years or more.

Specifically, given the increasing likelihood of PTEs occurring, we request that the AER considers streamlining the pass through application process so that prudent, and efficient but previously unforeseen, costs can be recovered in a manner that is less onerous for both the AER and industry participants.

Next, we discuss some areas of expenditure that are not reflected in our Revised Proposal but that are still likely to be incurred.

Bushfire zone reclassification costs

Bushfire risk is one of Essential Energy's biggest risks, and maintaining appropriate clearances around our powerlines is our single biggest operating expense. Our Proposal included over $1 billion for vegetation management over five years, based on a continuation of the current expenditure trends. Though we are not proposing any changes to our forecast expenditures in this Revised Proposal, we know that this amount is unlikely to be sufficient in addressing the increase in bushfire risks due to climate change and the risk reclassification of many of our bushfire zones.

As there is no other alternative available to us at this stage, we are nominating a new Bushfire Risk Reclassification PTE – see **Attachment 6.04**. This will enable us to apply to the AER to pass through, and therefore recover, our efficient costs for managing bushfire risk on our network, when the event is triggered.

One of the largest and most serious bushfires of 2019–20[8] was in Darawank on the Mid North Coast of NSW. The fire destroyed approximately 3,000 hectares of vegetation and no less than 16 buildings. A coronial inquiry was subsequently launched, with the final report expected in 2023 or 2024.

It is possible that the coronial inquiry will find that the fire was caused by overhanging branches falling onto Essential Energy powerlines, causing arcing that ignited the vegetation immediately below the powerlines. The coronial inquiry questioned the adequacy of Essential Energy's bushfire classification system, including the modelling that underpins it. Bushfire risk ratings are sourced from the Phoenix RapidFire bushfire simulation model, developed by the University of Melbourne. Other utilities and providers of essential services across eastern Australia, including the Rural Fire Service (RFS), use this model.

Essential Energy uses the Phoenix system to determine the risk rating for each of the 4,183 vegetation management areas in our network area. The areas with the highest risk are assigned a Priority 1 (P1) rating, and those with the lowest risk are assigned a Priority 4 (P4) rating. The risk rating dictates the vegetation clearance protocols that apply to each area. P1 areas must have 'clear to sky' clearances. P4 areas have the lowest required clearances. Clearance areas are highest for P1 areas.

Following the 2019–20 bushfires, the University of Melbourne updated its Phoenix system. This update was completed in 2022 and Essential Energy has since analysed the outcomes. Early indications are that the updated model means a significant increase in the number of areas in our network area with a P1 rating. The RFS is also focussing their resources on these new P1 areas. We are in the process of determining the costs of bringing the new P1 areas up to the P1 standard, but it will be material and will also be driven by affected communities' expectations. It is critical that we adequately engage with communities in determining the appropriate response to reducing risk in these new P1 areas. Most of the increased expenditure will be opex but, depending on the optimal solution, there may be some capex, such as for SAPS installations or undergrounding, as possible mitigants.

Some areas that are currently classified as P1 will be re-classified as P2 or P3. These will retain their P1 clearances to avoid incurring additional costs in the event they revert to the P1 classification in the future. This is consistent with other networks' practices. Moreover, communities in these areas expect the vegetation to be managed in this manner, particularly given that some areas have been subject to extreme fires over the past 5–10 years.

[8] The 2019–20 bushfires destroyed more than 3,200 poles and hundreds of kilometres of network infrastructure, resulting in significant unforeseen expenditure. Some of this expenditure was recovered through a Cost Pass Through Application (CPTA) that was approved by the AER in 2022.

Following the updated modelling of the Phoenix system, Essential Energy must develop and implement a plan to meet and comply with the new bushfire risk classifications for the emerging and materially higher bushfire risk and remediation profile on our network in the 2024–29 regulatory period.

At the time of submitting our Proposal to the AER in January 2023, we were not aware of the impact of the updated modelling of the Phoenix system. As such, no allowances were made for any additional costs related to this, either as an opex step change, a project, a contingent project or a new type of PTE.

We have not included this expenditure as an opex step change in our Revised Proposal, as we are still determining the costs and developing the optimal implementation plans. These will depend on the outcome of our engagement with affected communities. We also note the indication in the AER's Draft Decision for no further step changes.

We have not included this as a contingent project in our Revised Proposal, as at this stage we do not know how much capex will be required. The majority of this cost will be opex and therefore unlikely to meet the contingent project criteria outlined in section 6.6A of the NER.

These external developments do not currently, and may never meet the criteria of any of the prescribed PTEs laid out in clause 6.6.1 (a1) of the NER, nor the requirements of any of the nominated PTEs accepted by the AER in its Draft Decision.

We are therefore nominating a new type of PTE – Bushfire Risk Reclassification – in our Revised Proposal to recover the increased costs of vegetation management due to the reclassification of our bushfire risk.

Climate change and network resilience costs

As outlined in **Chapter 4**, extreme weather events due to climate change are having a significant impact on Essential Energy's network and operations. These events are becoming more frequent and severe, as evidenced by the bushfires of 2019–20, and the floods of 2020–21, 2021–22 and 2022–23.

During engagement, our customers told us very clearly that they expect us not only to maintain the reliability of the distribution network but also to improve its resilience – that is, its ability to withstand and recover from extreme weather events such as strong winds, bushfires and floods. They expect us to invest in programs such the rollout of durable composite poles, SAPS and microgrids, and underground our network in some high-risk areas. They also want us to invest in technologies such as network batteries to better regulate voltage levels and monitor our network so that we can take proactive steps to maintain continuity of supply.

Furthermore, they expect us to invest in assets such as portable generators, mobile SAPS units and streetlighting units to strengthen our communities' ability to withstand and recover from extreme weather events and natural disasters.

Accordingly, we included $314 million in our January Proposal to combat the effects of climate change and extreme weather events, and to make our network and communities more resilient.

The AER accepted the opex and capex proposals we submitted in January 2023 in its Draft Decision, so we are planning to roll out the programs of work described in that Proposal.

However, combating the effects of climate change and improving the resilience of our network are complex tasks. While we have sought to maintain or improve the reliability of the network for some time now, building network resilience is a relatively new concept. The measures we need to take to achieve our customers' resilience expectations, and the resultant cost forecasts in our Proposal, are based on the best information we had available at the time of preparation. We will need to be as alert, flexible and adaptable as possible, and may need to introduce new or unforeseen programs of work to achieve our resilience goals. This may or may not result in incremental expenditure, over and above what was included in our Proposal.

We encourage the AER to make the process to recover unforeseen costs that were not included in the approved allowance more flexible.

Cybersecurity costs

Cyber threats are one of the key risks all organisations and individuals face. As threats are increasing and constantly evolving, all organisations must take steps to ensure their information and operational technology assets and sensitive data are secure. Regulatory obligations underpin this.

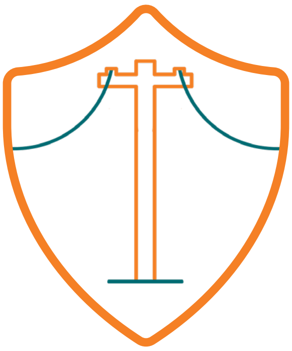
In our case, these threats are magnified because our electricity distribution network is deemed critical infrastructure and is therefore an attractive target for cyber criminals.

Essential Energy has cybersecurity obligations under its NSW distribution licence and the *Security of Critical Infrastructure Act 2018* (Cth) (SOCI Act).

Our Electricity Distributor's Licence requires us to ensure that our sensitive data and systems are secure and only accessed within Australia by authorised individuals, except in limited circumstances.

Under the Critical Infrastructure Risk Management Program (CIRMP) Rules that came into effect on 17 February 2023, Essential Energy must have attained, at a minimum, Security Profile level 1 (SP1) of the Australian Energy Sector Cyber Security Framework (AESCSF) by 17 August 2024. We will also selectively meet some of the requirements of SP2 and SP3, as determined by our risk-based approach to cyber security.

Our Proposal included expenditure plans to meet these obligations, and we are not suggesting any changes or additions in our Revised Proposal.



However, the cybersecurity landscape is changing rapidly, so it is highly likely that our risks and obligations will change during the 2024–29 period. At this point in time, it is impossible to determine with any great degree of certainty what additional cybersecurity measures we will need to introduce during this period, as new cyber risks may emerge and new or updated regulatory or legislative obligations may be introduced.

Cloud computing costs

The recent changes to the accounting treatment of cloud computing services mean that some costs that were previously capitalised will now be expensed (opex). While this does not change the total amount spent on cloud computing services, it does make the forecasting of operating costs and revenue requirements more difficult due to the lumpy nature of this type of expenditure.

The long planning horizon in the current regulatory framework makes it very difficult to forecast when certain types of expenditure will occur. The fact that cloud computing costs are now classified as opex, as opposed to capex, means that the impact of any timing variations is magnified. This also affects the outcomes of the EBSS incentive scheme for opex.

Other potential obligations and regulatory changes

The regulatory framework that Essential Energy operates in is evolving by necessity, and new obligations and responsibilities will continue to emerge. While many of the obligations over the 2024–29 period are known, there will inevitably be some new or amended obligations that we did not consider as we prepared our Proposal and this Revised Proposal. This is because we either did not or do not know about them, or because there is currently insufficient detail at this stage of the regulatory reform cycle.

Further obligations and material changes in circumstances and costs over the 2024–29 period will likely occur due to any of the following:

- the proposed classification of legacy metering services as standard control for Essential Energy
- the requirement to implement the AEMC's target of 100 per cent smart meter adoption by 2030
- the probable requirement to support the rollout of electric vehicle infrastructure
- the probable requirement to support the rollout of community batteries
- the requirement to support the rollout of increased levels of both small- and large-scale solar
- the requirement to support the increased rollout of SAPS
- the requirement to support the rollout of the NSW Government's Electricity Infrastructure Investment Roadmap
- required participation in the activities outlined in the 54 recommendations arising from the *Independent NSW Electricity Supply and Reliability Check Up* report, which include:
  - exploring options to finance small network upgrades needed to accelerate renewable generator connections
  - supporting an expansion of Essential Energy's apprenticeship program in regional NSW
  - identifying areas of existing network capacity to connect renewable generation in the short term
- the requirement to support the implementation of NSW's Climate Change (Net Zero Future) Bill 2020, which legislates reducing greenhouse gas emissions by at least 50 per cent by 2030 and achieving net zero emissions by 2050
- the requirement to support other government interventions
- the requirement to support the general trend towards increased electrification
- changes to the National Electricity Objective (NEO) or NER.

It is important to note that this list is not exhaustive, as the NSW Government is actively considering further interventions to meet its net zero obligations. Consequently, it is likely that NSW distributors, including Essential Energy, will be called upon to play an increasingly pivotal role in the delivery of evolving policy objectives.

For these reasons, the importance of revising Essential Energy's service classifications, as outlined in **Chapter 6**, cannot be overstated as it directly impacts our ability to adapt to, and effectively fulfil, these emerging roles and responsibilities. In a rapidly evolving regulatory landscape, the appropriate classification of our services is instrumental in ensuring that we meet current and future obligations while aligning with broader policy goals.

In addition to ensuring that appropriate service classifications are in place to reflect likely adjustments, the AER needs to be mindful of the potential need for adjustments to the TSS over the 2024–29 regulatory period given the pace of change and signalled government interventions. This consideration should be reflected in its assessment of the proposed TSS, which is based on current requirements reflecting our customer engagement. Tariff trials need to be properly scoped and completed prior to any tariffs being proposed, such as for EVs. We need to ensure that our tariffs provide the necessary signals and work appropriately for all parties. It is not unlikely that Essential Energy's TSS may need to be reopened prior to 2029, and all parties would benefit if there were a streamlined process to enable this to occur in the most efficient and effective manner.

Summary

The energy industry is undergoing a period of unprecedented change. This will continue for some years as Australia seeks to achieve its goals of 82 per cent of energy being sourced from renewable sources by 2030, and the 2030 and 2050 emissions reduction targets.

An increase in extreme weather events due to climate change, changing technology and shifting customer expectations means that energy companies constantly need to adapt and evolve their operating and business models to deliver safe, reliable and sustainable energy services to their customers at affordable prices. Electricity networks are at the epicentre of this transition and will need to make significant changes to their businesses to meet these challenges.

Essential Energy believes that the current regulatory framework is not agile or flexible enough to effectively meet these challenges. The current framework of five-yearly resets, and over-reliance on prescribed pass through events, is overly cumbersome and not nimble enough to keep up with climate and technological changes and shifting customer and stakeholder expectations. We have described, above, a multitude of likely changes in obligations and expectations on our business in the near future, and while most of them may meet the criteria of a prescribed PTE, this is not certain. Crucially, the requirement to meet the cost materiality for each and every different event, is beginning to skew the risk profile of the regulatory framework.

We recommend that the AER engages with industry participants to review its *Better Resets Handbook* to see what lessons can be learnt from recent reset processes.

Specifically, we also recommend that avenues to enable the recovery of reasonable, prudent and efficient costs that were not included in regulatory determinations, are reviewed and streamlined, resulting in mechanisms that are comprehensive in coverage, yet less onerous for both the AER and industry participants. This will enable participants to adapt faster and more effectively, in a manner that benefits customers and society in the long term.

06

Framework and approach

Chapter summary

- We have made additional changes to service classifications.
- Our CSIS approach has been finalised.
- A new nominated pass through event for bushfire risk reclassification has been included.

Framework and approach

In our Proposal, we accepted the AER's Final Framework and Approach NSW (F&A) for 2024–29[9], and highlighted that we intend to update the Customer Service Incentive Scheme (CSIS) in our Revised Proposal.

Since then, there has been a material change in circumstances in relation to our legacy meters, reflecting the expectations of the AEMC in its Review into Metering Services[10], as well as other external drivers that are also potentially material changes in circumstances. This means that further changes are now needed to some elements of the F&A.

In the rapidly evolving energy landscape, Essential Energy is navigating several key areas of focus to align with regulatory frameworks and best serve our customers and stakeholders. This chapter covers topical issues of metering service classifications, bushfire risk mitigation, and Essential Energy's emerging role in deploying batteries and providing essential system services.

This section also includes the rationale and wording for a new nominated PTE for changes to bushfire risk classifications.

We updated our proposed CSIS targets to reflect more recent data, and changed how our customer ease parameter will be measured. These changes are all supported by our customers.

The AER's Draft Decision was that an Export Services Incentive Scheme (ESIS) will not apply to Essential Energy in the 2024–29 regulatory period. The AER further noted that the ESIS was first published in June 2023 and was not available at the time of Essential Energy's Proposal. Our intention is to work with customers in the coming years to develop an ESIS for the 2029–34 regulatory period.

We accept the AER's Draft Decision on:

- the continued application of the current incentive schemes for 2024–29:
  - the demand management incentive scheme (DMIS)
  - the demand management innovation allowance mechanism (DMIAM)
  - the Efficiency Benefit Sharing Scheme (EBSS)
  - the Capital Expenditure Sharing Scheme (CESS)
  - the Service Target Performance Incentive Scheme (STPIS) – with adjustments to the model for approved resilience investments, and excluding the customer service component
- control mechanisms (subject to updates for metering as reflected in the AER's guidance note[11]), and
- our negotiated services framework.

Further discussion on Essential Energy's outcome from the EBSS in 2019–24 is discussed in **Chapter 3** and in **Attachment 3.07**.

Changes to the classification of services

We are proposing changes to the following items in the classification of services table (see **Attachment 6.01**).

Following are the proposed changes to metering:

- Existing services related to owning and maintaining the current fleet of Type 5 to 6 metering installations and legacy meters move from alternative control to **standard control services.**
- New services that may be deemed the responsibility of the distributor are to come under **standard control services.**
- Other legacy metering services that are customer-initiated and financially attributable to the requesting party remain in **alternative control services.**
- Activities that governments or regulators request us to carry out in order to accelerate smart meter rollouts may be either **alternative control or standard control services.**
- The **unregulated and not classified** Contestable Metering Support item should be amended to reflect additional services that may be requested for the smart meter rollout.
- Add the provision of standardised network data into **standard control services** to reflect data that is free or low cost.
- Update the existing provision of non-standardised data in **alternative control services** to include related services.

Other items for clarity and to streamline/formalise existing practices and where existing ring fencing waivers are in place:

- Add Essential System Services as an **unregulated and not classified** distribution service.
- Add the leasing of excess battery capacity as an **unregulated and not classified** distribution service.
- Include the words 'EV chargers' as an example of distribution asset rental in **unregulated and not classified** distribution services.

---

[9] AER, Framework and approach – Ausgrid, Endeavour Energy and Essential Energy (New South Wales), July 2022. Link

[10] AEMC, Final Report – Review of the Regulatory Framework for Metering Services, August 2023. Link

[11] AER, Legacy metering services – Guidance note, November 2023 Link

Changes to the Customer Service Incentive Scheme

Our proposed CSIS design was based on our performance measurement of the following three parameters:

1. Communicating estimated unplanned outage resolution times
2. Resolving complaints in a timely way
3. Improving customer satisfaction, as measured by a 'customer ease' score.

Parameter 3 was subdivided into two elements, reflecting two different data sources:

> **Parameter 3(a):** Customer satisfaction as measured by the quarterly 'customer ease' score of between 1 and 5. A score of 1 represents best performance and a score of 5 represents worst performance.

> **Parameter 3(b):** Customer satisfaction as measured by the post-interaction survey 'customer ease' score of between 1 and 5. A score of 1 represents the poorest performance and a score of 5 represents the best performance.

Each of these parameters had a weighting of 10 per cent in the CSIS design, giving customer ease an overall weighting of 20 per cent.

Since submitting our Proposal, Essential Energy has changed from using the quarterly survey process for Parameter 3(a), as managed by a third party, to implementing a more timely and comprehensive in-house system of rolling surveys. This provides greater coverage of our customer base and gives a more robust sample on which to base customer satisfaction results. However, given this system was implemented only recently (September 2023), there is an insufficient data history to establish a reliable baseline for target setting.

Based on customer and stakeholder feedback, we amended our CSIS design to remove Parameter 3(a) and to base the customer ease parameter entirely on the Parameter 3(b) Contact Centre post-interaction survey. The weighting for Parameter 3(b) has been revised from 10 per cent to 20 per cent to reflect this change. This was supported by customers and stakeholders. The weightings for parameters 1 and 2 remain at 50 per cent and 30 per cent, respectively.

The AER's Draft Decision is to approve our proposal to measure and target the performance parameters set out above and to accept our amendment to its proposal, to base its customer ease parameter on the Contact Centre post-interaction survey measure only.

After submitting our proposal, we continued to track our performance for the proposed CSIS measures and have used data up to the end of September 2023 to update our targets and incentive rates for the Revised Proposal. We shared the updated details with customers and stakeholders as part of our engagement process in October 2023. The AER's Draft Decision states that it will set final CSIS targets and incentive rates based on updated performance data in, and customer feedback to, the Revised Proposal.

Further information on the CSIS is provided in **Attachments 6.02 and 6.03**.

Pass through events

In our Proposal, as well as renominating the four existing PTEs of natural disasters, terrorism, insurance coverage and insurance credit risk, we proposed a new event for major cyber (as well as some refinements of existing definitions into plain English). The AER has rejected those changes, and instead retained the existing four nominated events and their current definitions. We accept the AER's decision on those events.

However, as discussed in **Chapter 5**, at this Revised Proposal stage we now have to contemplate a unique set of circumstances that require us to propose a new nominated PTE for 2024–29.

Essential Energy is including a new nominated PTE for 'Bushfire Risk Reclassification', as the existing categories of events already prescribed in the NER would not apply. There are some uncertainties around defining the trigger event in a way that satisfies the AER. This is because the AER has indicated that a PTE can only be triggered by an 'external' event, such as a change in law. In the case of the bushfire risk reclassification, it is not a change in law, rather it is a change in risk as determined by appropriate analysis. Initially we had suggested that the trigger event be the submission to the AER of a detailed and independently verified plan for addressing the new risk profile, but this approach was not accepted. We remain willing to work with the AER to ensure we have the opportunity to recover these funds in 2024–29 if they are material and justified, and following endorsement by the AER and our customers.

Refer to **Attachment 6.04** for further information on this event and the proposed definition.

07

Operating expenditure

Chapter summary

- The AER accepted our opex forecast for main SCS services in its Draft Decision as its alternative estimate was not materially different.
- Updates to the main SCS opex forecast in this Revised Proposal are limited to mechanistic updates, including a base year adjustment to implement the SaaS accounting rule.
- Combined main SCS opex and legacy metering SCS opex is shown in accordance with the AER's legacy metering guidance.

Operating expenditure

We based our opex forecast in the Proposal on our engagement with customers and key stakeholders. The AER accepted the overall amount of proposed opex in its Draft Decision. While no further material changes are proposed, and we retained the step changes proposed, mechanistic updates have been made to the main SCS opex proposal for the 2024–29 period.

As legacy metering services are reclassified as SCS in our Revised Proposal, the combined opex forecast for main and legacy SCS is also provided. Please see **Chapter 11** for further details on metering opex forecasts.

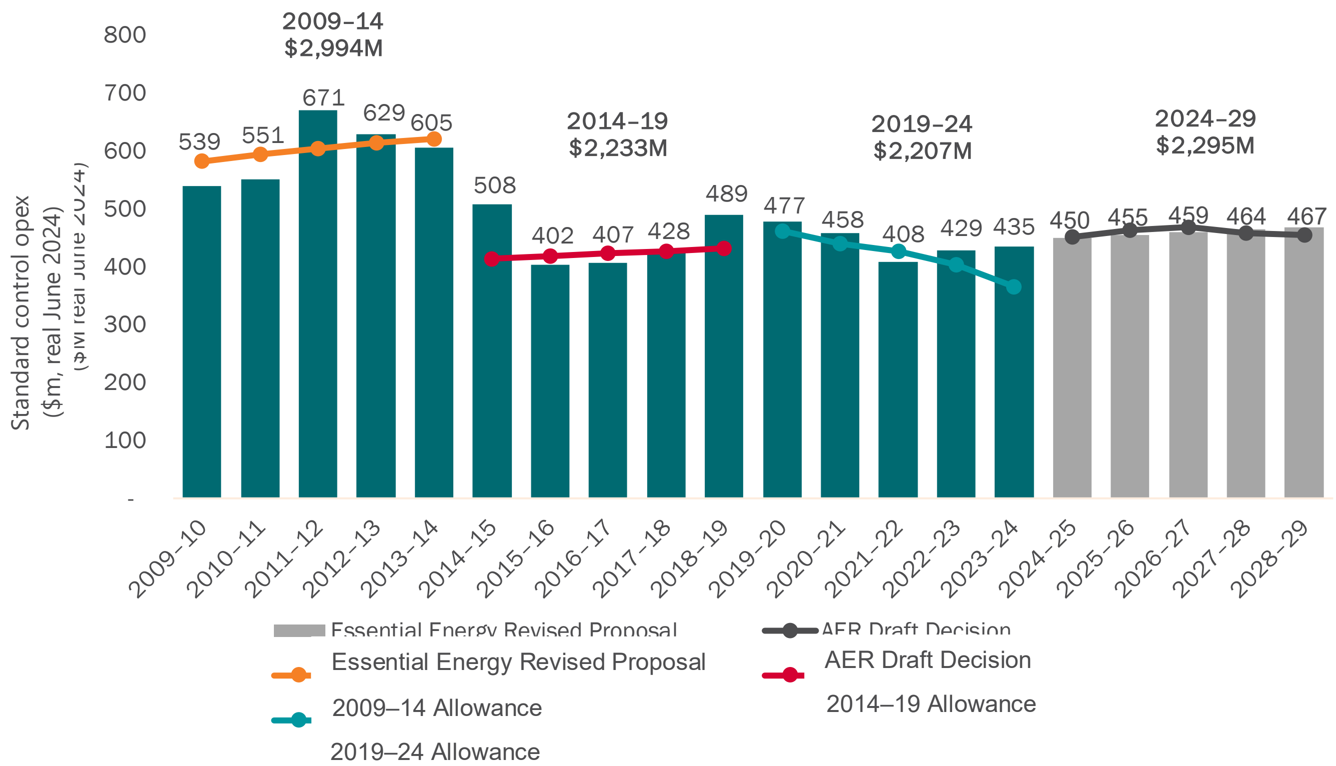
Main SCS operating expenditure

We had previously highlighted to the AER and our customers that additional opex step changes beyond those in our Proposal may be required for the 2024–29 period. We have delayed material step changes until we are certain about operating costs, including those related to cyber security and bushfires. Other expected step changes related to building network resilience have been offset by cost savings that we expect to achieve over the 2024–29 period, including avoided network costs due to the installation of stand-alone power systems (SAPS).

Proposed main SCS opex for the 2024–29 period is $2,323 million (real $2024 and including debt-raising costs).

As shown in Figure 6, we expect real opex in 2024–29 (excluding debt-raising costs) to be only 4 per cent higher than in the 2019–24 regulatory period. This is a modest increase that maintains operating costs at an efficient level, while supporting customers and the energy transition.

Figure 6: Proposed operating expenditure compared to historical expenditure and allowances (excludes debt-raising costs)



–

Updates to main SCS operating expenditure

Mechanistic updates that have been applied to prepare the Revised Proposal 2024–29 opex forecast are as follows.

1. Updated base year

Two mechanistic updates have been applied to the base year (2022–23) opex that is used to develop the 2024–29 forecast:

- the inclusion of actual, audited 2023–23 opex
- the application of the SaaS accounting rule.

Actual 2022–23 opex

We have maintained 2022–23 as our base year for developing opex forecasts for the 2024–29 regulatory period. This will be the most recent financial year of actual expenditure available at the time of the AER's final determination.

Actual base year opex reflected in this Revised Proposal is $429 million (real June 2024), compared to $445 million (real June 2024) forecast in our Proposal.

SaaS accounting rule

As previously agreed with the AER, the International Financial Reporting Interpretations Committee (IFRIC) accounting rule on SaaS will be implemented at the commencement of the 2024–29 period. This will reclassify a proportion of ICT costs that were capitalised (treated as capex) to be expensed (treated as opex).

The AER's Draft Decision (**Attachment 6**, p. 26) noted that while Essential Energy had estimated a cloud computing step change reflecting incremental costs for the 2024–29 period, it was not clear that this accounting change was included within our base opex, which would be via a base-year adjustment:

> *We note that Essential's approach therefore appears to account for any step up in SaaS opex required from its base year, but it is not clear that this includes the base year SaaS amount. We consider Essential should consider this further in preparing its revised proposal and, if this is the case, it may be appropriate for Essential to include a base adjustment for SaaS costs (including those incurred in its base year) in its revised proposal.*

We mistakenly excluded a base adjustment for SaaS costs from our January 2023 Proposal, but this has now been corrected in this Revised Proposal. The value of the base year adjustment is $4.9 million (real June 2024).

Our base year is efficient

The AER's Draft Decision (**Attachment 6**, p. 16) determined that Essential Energy's base year opex is not materially inefficient.

We note that the AER will update its analysis of the efficiency of Essential Energy's base year opex using our actual opex (which is below the opex forecast assessed by the AER in the Draft Decision) and updated comparator data and models from the 2023 Annual Benchmarking Report.

We expect that there will be no change to the AER's conclusion that our base year opex is not materially inefficient.

2. Updated trend parameters

The second element of mechanistic updates to the 2024–29 opex forecast are updates to the output growth and price growth trend parameters.

Output growth

We updated our forecast output growth to reflect more recent data on output measures for customer numbers, circuit length and ratcheted maximum demand.

Price growth

Oxford Economics Australia has prepared updated Wage Price Index (WPI) forecasts, which are applied in the Revised Proposal 2024–29 opex forecast. Essential Energy has applied an average of the updated Oxford Economics Australia WPI and the WPI applied by the AER in the Draft Decision (**Attachment 6**, p. 21). The Oxford Economics Australia report is provided in **Attachment 7.02**.

Our updated price growth ranges between 0.48 per cent and 0.84 per cent for each year in the 2024–29 regulatory period.

Productivity

The annual productivity improvement of 0.50 per cent for each year of the next regulatory period, which accords with the AER's Draft Decision (**Attachment 6**, p. 19), remains unchanged.

3. Updated step changes

The final element of the mechanistic updates relates to the proposed opex step changes. While the AER's Draft Decision recommended lower step change forecasts, the overall opex forecast was accepted by the AER. The proposed step changes in this Revised Proposal are unchanged.

However, mechanistic updates to the step changes are applied as follows:

- Cloud computing – the expenditure profile has been smoothed to better reflect expenditure programs and minor cost allocation method (CAM) updates that arose as a result of the mechanistic changes to the main SCS opex and capex forecasts and updates to the legacy metering SCS and ACS forecasts
- Insurance – a minor CAM update, as above
- Future network – a minor CAM update as above
- Guaranteed Service Levels (GSLs) – no change
- Property and fleet – a minor CAM update, as above.

The Revised Proposal step changes total $54 million (real June 2024), as shown in Table 18.

As noted previously, Essential Energy had indicated to the AER and our customers that additional opex step changes beyond those in our January 2023 Proposal may be required for the 2024–29 period. This Revised Proposal does not include additional step changes, as required step changes have either been offset by expected efficiency savings or deferred until more information is available.

The step changes that have been offset by expected efficiency savings relate to network resilience expenditure. We expect to incur an additional $15 million (real June 2024) over the 2024–29 period as a result of:

- providing community resilience personnel as part of our resilience investment case. This includes three personnel dedicated to working with councils, communities and infrastructure providers to develop and implement resilience plans and to be 'on ground' during adverse weather or other natural disaster events
- higher unplanned maintenance due to the expected increase in weather-related asset failure.

As a result of the forecast SAPS installations in the 2024–29 period, we avoided opex that would otherwise have been incurred with a network solution including network inspection, vegetation management and faults and emergency opex. This opex saving is expected to offset the additional resilience-related opex identified above.

Two further step changes have been deferred, also noting the AER's Draft Decision and their preference to minimise step changes.

- **Cyber security:** The intended release and introduction of the AESCSF V2 is delayed. Essential Energy will review the AESCSF V2 requirements when these are available to determine what impact they are likely to have on our cybersecurity costs. If it is likely necessary to incur material additional costs within the 2024–29 period, a cost pass through application may be submitted.

- **Bushfire risk reclassification:** Essential Energy has worked with Melbourne University to significantly improve its modelling and data capabilities in identifying bushfire risk across its network footprint. These improvements have changed our understanding of our high-risk network areas; with areas that were previously considered to be lower risk, now seen as high-risk areas. Work is underway to fully assess the implications, including those associated with meeting our relevant network management obligations and cost impacts. Within this Revised Proposal (**Attachment 6.04**) we are proposing an additional nominated PTE to address any material cost impacts of implementing the new bushfire risk classification and management system.

4. Updated debt-raising costs

For this Revised Proposal, we updated our forecasts of debt-raising costs using the formula-driven approach in the AER's PTRM. Debt-raising costs are forecasted at $28 million (real June 2024).

Summary of updated Revised Proposal opex

The updated 2024–29 forecast including debt-raising costs is shown in Table 18.

Table 181920: Proposed operating expenditure base step trend 2024–29 ($m, real June 2024)

	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Base opex	429	435	436	436	436	436	436	
Real price growth			0.80%	0.84%	0.53%	0.48%	0.58%	
Output growth			0.73%	0.73%	0.72%	0.72%	0.71%	
Productivity growth			0.50%	0.50%	0.50%	0.50%	0.50%	
Step changes			9	10	10	12	12	
Category specific								n/a
Proposed opex before debt raising			450	455	459	464	467	2,295
Debt-raising costs			5	5	6	6	6	28
Proposed opex after debt-raising costs			455	460	464	470	473	2,323

Numbers may not add up due to rounding.

Combined main SCS and legacy metering SCS opex

The combined main SCS and legacy metering SCS opex forecasts are provided in Table 19. The combined opex forecast over the 2024–29 period is $2,478 million (real June 2024).

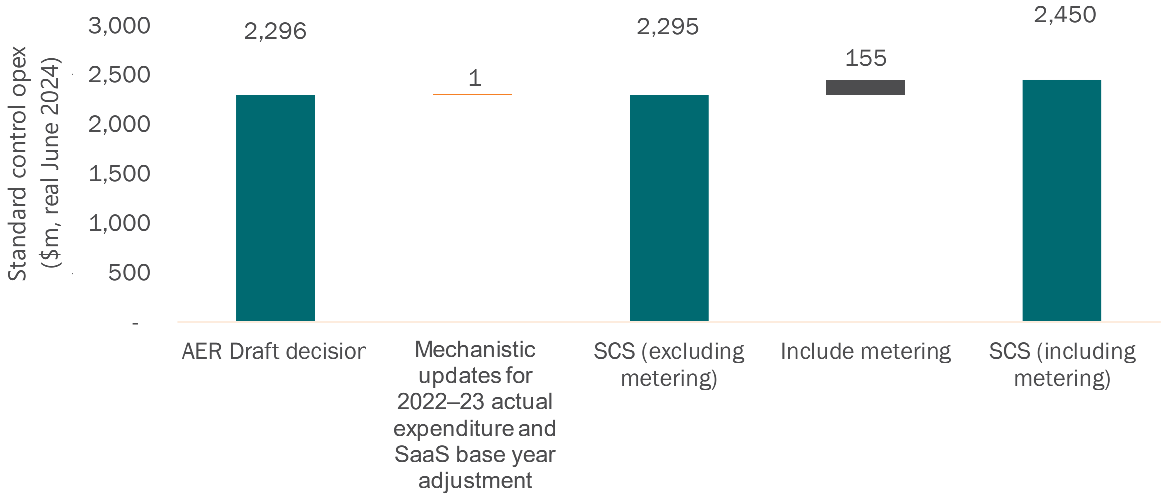
Table 2122: Main SCS and legacy metering SCS opex forecast ($ million, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Main SCS opex (incl. debt-raising cost)	455	460	464	470	473	2,323
Legacy metering SCS opex	32	35	33	31	24	155
Total	**487**	**496**	**497**	**501**	**497**	**2,478**

Numbers may not add up due to rounding.

Figure 7 shows the change in the SCS opex forecast from the AER's Draft Decision. This shows that the mechanistic updates to the main SCS opex forecast does not make any material change to the forecast. The only material change is the reclassification of legacy metering services from ACS to SCS.

Figure 7: Opex forecast updates including legacy metering SCS ($ million, June 2024), excluding debt-raising costs



08

Capital expenditure

Chapter summary

- The AER accepted our capex forecast in its Draft Decision as its alternative estimate was not materially different.
- We are not proposing any changes to our main SCS capex forecast.
- As legacy metering services are reclassified as SCS in our Revised Proposal, the combined capex forecast is also provided.

Capital expenditure

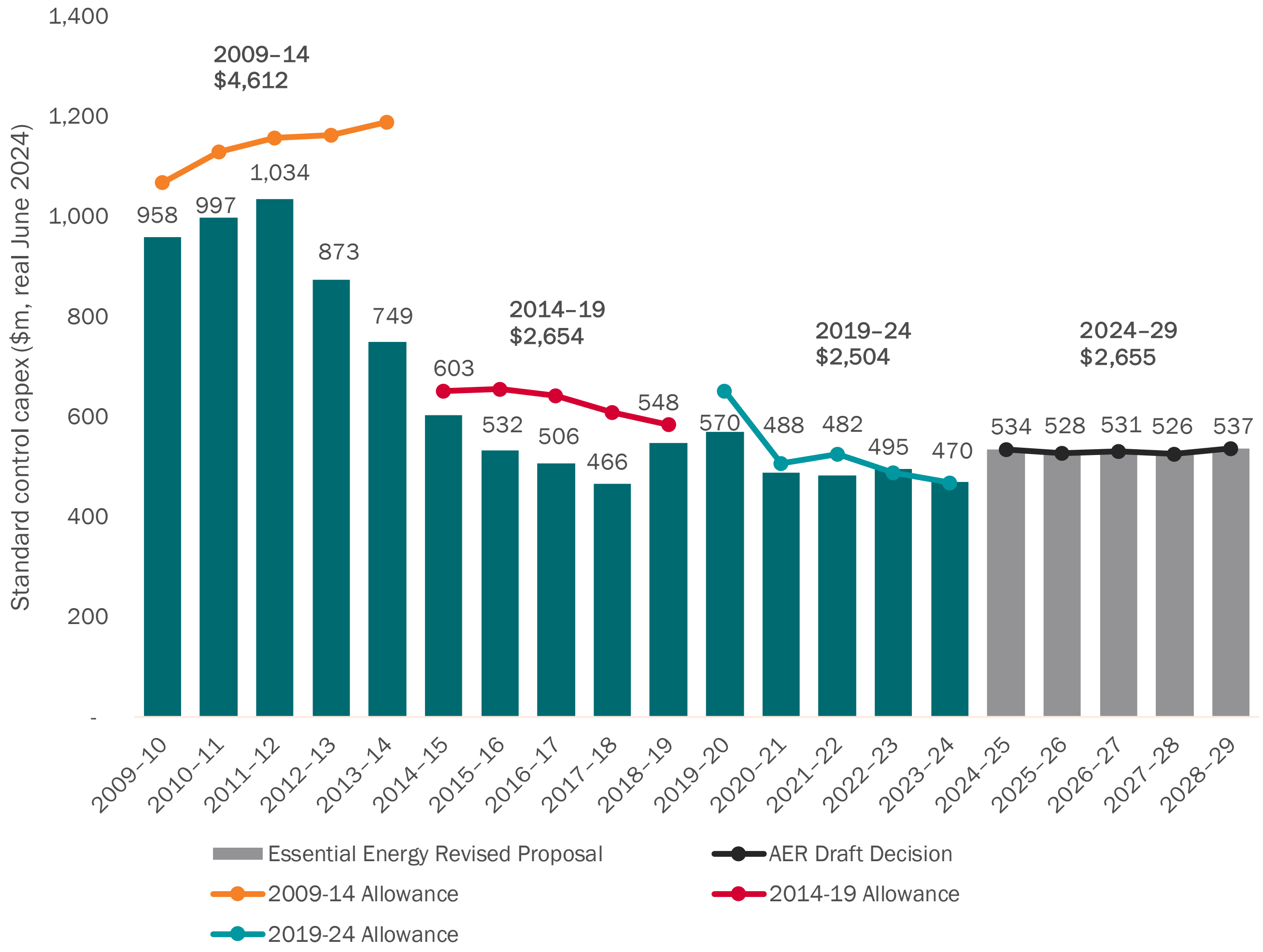
The AER's Draft Decision (Attachment 5, p. 3) accepted the total net capex forecast for main SCS from our January 2023 Proposal, subject to additional information our SAPS program being provided with this Revised Proposal (see **Attachment 4.01**). The AER accepts that this forecast reflects prudent and efficient costs to maintain the safety, reliability and security of the network. We do not propose further changes to the main SCS 2024–29 net capex forecast, and therefore rely on the AER's capex model as provided in their Draft Decision. We have also applied the updated asset categories and lives provided in their PTRM.

As legacy metering services are reclassified as SCS in our Revised Proposal, the combined capex forecast for main and legacy SCS is also provided.

Main SCS capital expenditure

This final forecast compared to historical forecasts is shown in Figure 8. In 2024–29, total net capex is forecast at $2,655 million – 4 per cent higher than net capex in 2019–24.

Figure 8: Proposed capital expenditure compared to historical expenditure



Note: For previous periods, capex is shown prior to disposals. For the 2024–29 period, capex is shown after disposals.

Table 23: Proposed capital expenditure by category ($m, real June 2024)

	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Replacement	209	217	226	224	242	1,117
Augmentation	29	28	29	29	32	148
Connections	30	29	29	29	30	147
Export services	11	11	11	11	11	54
Total system capex	**279**	**285**	**294**	**293**	**315**	**1,466**
ICT	37	30	25	22	25	139
Fleet	38	37	36	39	33	184
Property	31	23	22	27	23	125
Total non-system	**107**	**90**	**83**	**88**	**81**	**448**
Capitalised overheads	**166**	**170**	**172**	**162**	**159**	**830**
Total gross capex	**553**	**545**	**549**	**543**	**555**	**2,744**
less capital contributions	17	15	16	15	17	80
less disposals	1	2	2	2	1	9
Total net capex	**534**	**528**	**531**	**526**	**537**	**2,655**

Numbers may not add up due to rounding.

Combined main SCS and legacy metering SCS capital expenditure

The combined main SCS and legacy metering SCS capex forecasts are provided in Table 21. The combined capex forecast over the 2024–29 period is $2,671 million (real June 2024).

In accordance with the AER's guidance relating to legacy metering services[12], legacy metering capex is limited to non-network capex. Total non-network capex for both main SCS and legacy metering SCS is $464 million (real June 2024).

Table 24: Main SCS and legacy metering SCS forecast net capital expenditure ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Main SCS net capex	534	528	531	526	537	2,655
Legacy metering SCS net capex	4	4	3	3	2	16
Total net capex	538	531	534	529	539	2,671

Numbers may not add up due to rounding.

Connection Policy

The AER's Draft Decision did not approve our proposed Connection Policy, primarily due to the publication of their updated Connection Charge Guideline in April 2023 after our Proposal was submitted. An updated Connection Policy (following consultation with us) was included with the Draft Decision, but the AER also noted further engagement was needed around incorporating SAPS into this appropriately. Woolcott Research undertook an in-depth survey in October 2023 with some prospective SAPS customers to inform the appropriate threshold at which customers would need to contribute, if the size of a regulated SAPS needed to be increased after installation. See **Attachments 2.02 and 2.04** for further detail on this engagement and how we have addressed customer feedback on SAPS in the Connection Policy.

We provide a revised version of our Connection Policy with these changes, plus other minor updates including improved clarity around when we may look to amend agreed connection capacity, in **Attachment 8.02**.

[12] AER, Legacy metering services – Guidance note, November 2023 Link

09

Our approach to pricing

Chapter summary

- Our average distribution network charges (including metering) will increase by 0.43 per cent a year over the 2024–29 regulatory period before inflation.
- We have consulted customers about the proposed changes to our TSS and made decisions based on their feedback.

Our approach to pricing

The AER accepted the following aspects of our TSS in its Draft Decision:

- tariff assignment and structure for residential and small business customers
- tariff assignment and structures for low- and high-voltage (HV) commercial customers
- the introduction of network tariffs for utility scale storage (grid-scale batteries) connected to the low-voltage (LV) distribution network
- the contingent tariff adjustment to adjust the peak charging window if the peak moves
- the assignment and reassignment policies and procedures for retail customers
- export reward tariffs for residential and small business customers and large LV businesses.

The AER did not accept some areas of our proposed TSS and we have considered these as part of the adjustments included in our Revised TSS. We have also considered and included further stakeholder feedback during the engagement process and since the submission of the January 2023 TSS in this Revised Proposal.

At a high level, we have:

- adjusted the Sun Soaker two-way residential and small business tariffs by:
  - simplifying the export charges by reducing the number of export bands from three to two
  - changing the method of charging from kW to kWh, aligning with the recommendation from the AER in the Draft Decision
  - simplifying the proposed transition to assign all customers with a new connection or changes to an existing meter to the Sun Soaker two-way tariff from 1 July 2024, with the export price and rebate set at zero for 2024–25
- adjusted the network tariffs for utility scale storage (grid-scale batteries) by:
  - extending the large LV and HV battery eligibility criteria to include hybrid connections that have generation and storage
  - adding a new tariff for small batteries connected to the LV distribution network
  - removing energy charges while keeping demand charges
  - removing export rebates for HV distribution network connections
  - reducing the HV export tariff to reflect the HV export LRMC only
- reclassified legacy metering services as SCS in line with AER guidance and following support from customers. This is discussed further in **Chapter 11**.

We have also provided additional information requested in the AER's Draft Decision. This includes more granular customer bill impact analysis, details of our engagements since our January 2023 Proposal, and further information on our approach to site-specific tariffs and implementation of the NSW Government's green hydrogen producers tariff concession scheme.

Refer to **Attachment 9.01**.

Indicative bill impact

In accordance with the AER's guidance,[13] legacy metering costs will be recovered from all customers at the low voltage level via an addition to the fixed charge. Essential Energy noted the AER's preference to introduce the full price increase in the first year of the regulatory period (2024-25). Our SCC confirmed that we should introduce it so that it resulted in the lowest overall price volatility. The introduction of legacy metering recovery in year one, combined with the main SCS recovery of steadily increasing prices, does this. For further detail on our engagement see **Attachment 2.03**.

With the metering charge included, a typical residential customer bill will increase by just over $36 per annum on average over the 2024-29 period, or around 4% per annum on average in real terms. It should be noted that this bill impact will vary between customers, depending on the extent of their current metering charge.

Indicative changes to our SCS network charges

The actual network charges our customers pay during 2024–29 will depend on:

- the AER's final determination for Essential Energy for this regulatory period

[13] AER, Legacy metering services – Guidance note, November 2023 Link

- any changes in the relative proportion of revenues recovered from each distribution network charge and component during this period
- the transmission costs, climate change levy and NSW Electricity Infrastructure Roadmap charges passed through to Essential Energy
- inflation and costs of funding (updated annually), as discussed in **Chapter 3**
- the application of incentive schemes.

While we cannot predict the exact impact of these factors on our charges, the NER require us to provide a pricing schedule as part of our TSS that sets out the indicative charges we will apply for each year of the regulatory period. We have provided this in **Attachment 9.04**.

Forecast changes to average charges

The average changes to distribution network charges are calculated by dividing our proposed annual revenue requirements by the total energy consumption forecasted for each regulatory year. Average changes may vary for each customer, based on their consumption level. They will also likely differ from the percentage change in revenue.

Table 25: Forecast change in average distribution charge (% change in real charges)

	2024–25	2025–26	2026–27	2027–28	2028–29	Average
Average real change in distribution charges	1.38%	(0.01%)	(0.27%)	0.59%	0.44%	0.43%

Revised TSS

The AER uses our TSS to assess our compliance with the NER and its export tariff guideline, which requires us to develop distribution network charges that reflect the efficient cost of providing two-way network services to individual customers. Our Revised TSS and Revised TSES (**Attachments 9.01 and 9.02**) explains how we will apply distribution network charges to our customers over the regulatory period.

Once our Revised TSS is approved by the AER, it will replace our current TSS which applies to 30 June 2024.

I found the information interesting and informative. For example, the benefits of solar panels for consumers is now more about consumption rather than how much you make from exporting to the Grid. It has made me consider whether I upgrade my solar system and look to invest in battery technology. The information around smart meter vs traditional Meters was very interesting as well. The webinar makes me really think what we as a household could do to reduce our power consumption during peak times and vice versa.

Survey participant

10

Alternative control services

Chapter summary

- We have accepted most of the AER's Draft Decision for ancillary network services but have made some adjustments.
- We reduced our public lighting prices following further engagement, and they are now closer to those in the AER's Draft Decision.
- We propose that metering services become part of standard control services for 2024–29.

Changes to alternative control services

ACS are customer-specific or customer-requested services. These services may also be provided on a competitive basis rather than only by a Distribution Network Service Provider (DNSP).

For our Proposal, we followed the AER's F&A and included Type 5 and 6 metering installations and legacy meters as ACS, reflecting their classification in the 2019–24 regulatory period.

However, in response to the AEMC's Metering Review and AER (and customer) preferences, we propose that metering services be classified as standard control. Please see **Chapter 6** and **Chapter 11** for information on the reasons for, and the implications of, this proposed change.

Therefore, for the purpose of this Revised Proposal, ACS means only ancillary network services (ANS) and public lighting.

Ancillary network services

Our Proposal included 189 individual ANS that are either fee-based or quoted services provided to individual customers. These are subject to an AER price cap. Fee-based services are homogenous and the prices we propose are based on average cost inputs and completion times. Quoted services are provided using the approved rates.

The AER's Draft Decision did not accept all aspects of our Proposal for ANS. It accepted most of our after-hours labour rates but not our business-hours labour rates. Our proposed overhead rate of 65.57 per cent and the application of margins and tax rates on top of this were also rejected, as were the assumed times to conduct special meter tests. In addition, the AER substituted our proposed ANS X-factors with its own labour price growth forecasts and revised our Year 1 prices for fee-based services.

In this Revised Proposal, Essential Energy accepts most of the AER's Draft Decision for ANS, including the change for minor capital works from being fee-based to being quoted, but excluding special meter tests. We have included minor adjustments for actual FY24 escalators and forecasted inflation aligned with standard control services, and updated some material fee-based services for material on-costs (as accepted in the current regulatory period). We have also included some service fee changes for new types of security lights (and tariff contract changes), connection fees replacing access permit fees, and a new quoted fee service for data requests.

These changes – and associated prices – are reflected in our Revised Proposal for ANS.

Our revised service descriptions, ANS labour costs build-up and pricing model are included in **Attachment 9.06**.

Attachment 10.01 provides more information on the cost and pricing changes we have made to ANS in the Revised Proposal.

Public lighting

Public lighting includes the provision, construction and maintenance of public lighting assets - the main customers are local councils and Transport for NSW.

The AER's Draft Decision made significant top-down cuts to our public lighting service prices in our January 2023 Proposal and recommended that we engage further with stakeholders.

To address this, Essential Energy held a two-day face-to-face Public Lighting Forum in August 2023 on our public lighting services and Proposal. The forum was attended by representatives of 20 councils and two joint organisations, and two Southern Lights consultants. This allowed for constructive engagement and provided clarity and increased transparency to all parties. It also resulted in several important adjustments to our public lighting model that have been incorporated into our Revised Proposal.

While we did not reach an agreed position on all the elements with all parties, this Revised Proposal offers the average customer a real reduction of 11 per cent on their public lighting network charges, compared to current charges. We consider that this position provides price reductions that are more aligned with stakeholder expectations.

The key changes we have made in our Revised Proposal are as follows.

> Traffic control prices decreased by 36 per cent for maintenance rates and 28 per cent for replacement rates.
> Night patrol prices decreased by 17 per cent, which is 15 per cent lower than the AER's Draft Decision.
> Average Category V prices decreased by 14 per cent for standard LEDs and 21 per cent for High Intensity Discharge lights.

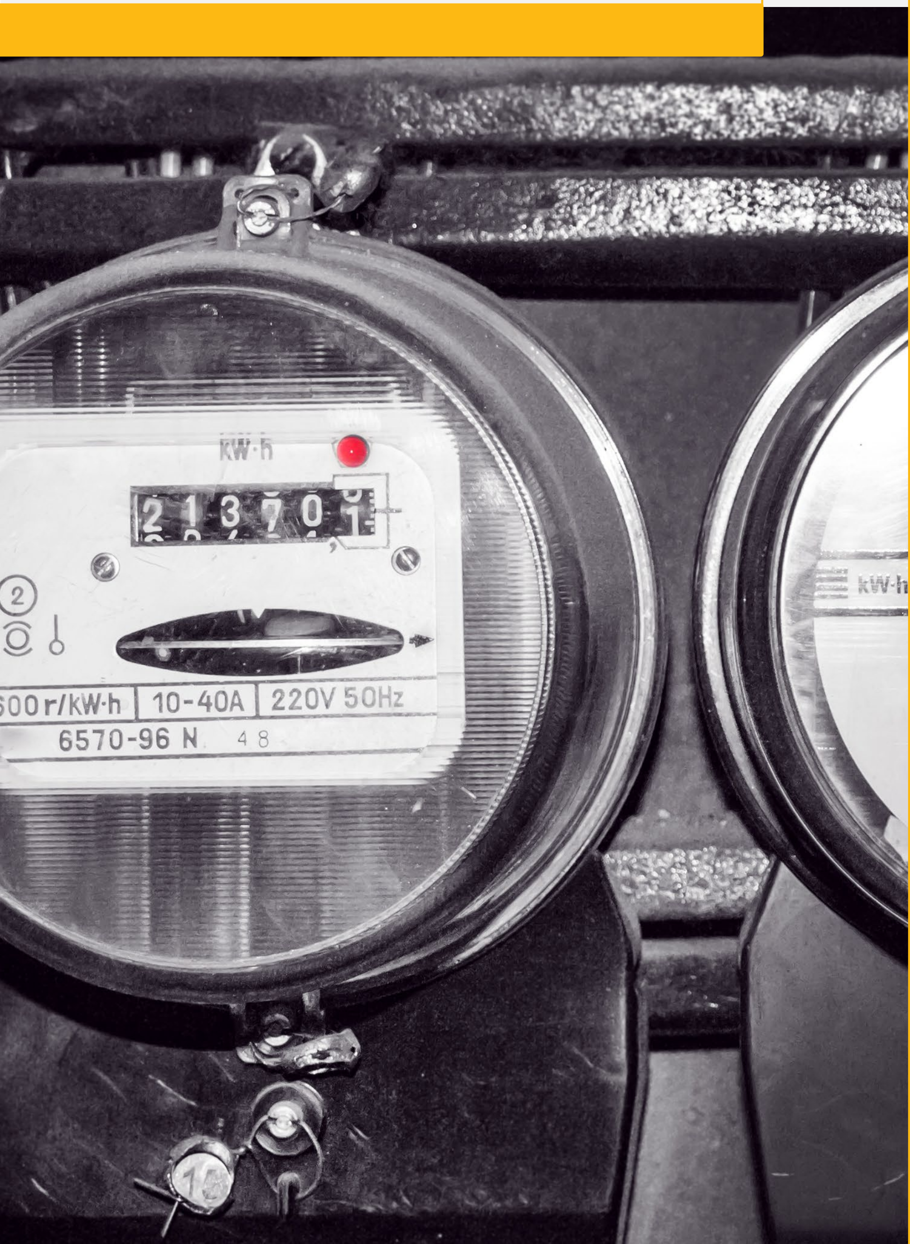
These are as a result of:

> accepting the AER's Draft Decision changes to inflation, WACC and labour rates
> removing audit costs and floodlight design time
> updating asset volumes to reflect current inventory and forecast
> increasing labour productivity to reflect current productivity based on analysis of current data
> updating warranty calculations, warranty acceptance, and LED failure rates based on current data
> reducing the traffic controller hourly rate to reflect revised average contract values
> correcting some errors throughout the model for labour, materials and plant
> Reverting to annuity pricing and removing the weighted capex pricing methodology (excluding Category V brackets)

Further information on our Revised Public Lighting Proposal can be found in **Attachment 10.05**.

11

Metering



Chapter summary

- We have updated our metering forecast to implement the AEMC's recommendation to accelerate the replacement of legacy meters with smart meters.
- We have reclassified legacy metering services as standard control services.
- These changes accord with new AER guidance and customer support.

Changes to metering services

Essential Energy provides legacy metering services to small customers with Type 5 and 6 meters. Industry reforms to accelerate the replacement of these meters with smart meters have been announced. This Revised Proposal provides amended metering expenditure, revenue forecasts and metering charges for the 2024–29 regulatory period that reflect the intended accelerated replacement program.

This Revised Proposal reflects the AER's preference to reclassify legacy metering services as standard control services (SCS) (from alternative control services) as outlined in its Draft Decision.[14] Essential Energy supports the AER's desire to reclassify metering as SCS within the revenue cap form of control. This will allow more equitable recovery of legacy metering costs from customers, given the whole-of-system benefits that smart metering will provide.

Essential Energy consulted with customers and key stakeholders about the proposed change to the service classification and the implications (including bill impacts) of the wider cost sharing (see **Chapter 2**). Our customers support this change.

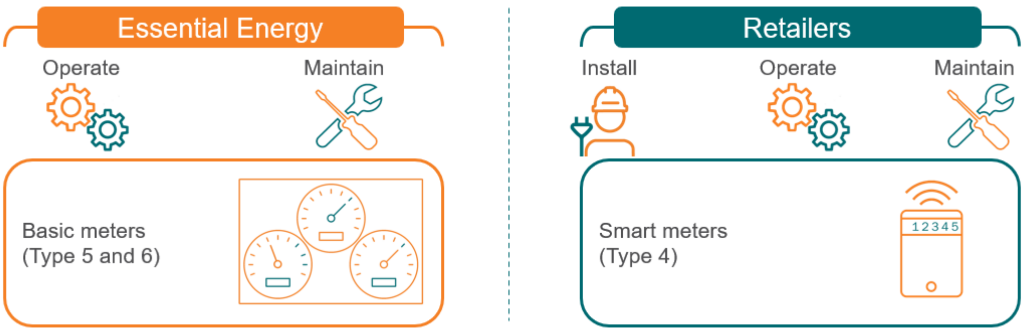
Further detail and supporting information about the change to the service classification are available in **Chapter 6** and **Attachment 6.01**.

Legacy metering services

From 1 December 2017, the provision of new or replacement meters became fully contestable under the Power of Choice framework, making new meters the responsibility of retailers. While Essential Energy no longer installs new meters, it continues to be responsible for operating and maintaining the remaining Type 5 and 6 meters (referred to as legacy meters) in place at small customer premises (i.e. customers using less than 160MWh of electricity per annum). Around 70 per cent of small customers in our network still have Type 5 or 6 meters.

Type 6 meters are older electromechanical meters that measure the total amount of electricity consumed between meter readings and are read manually. Type 5 meters provide interval metering (i.e. the meters measure consumption in 30-minute intervals) but do not meet the full requirements of a smart (Type 4) meter and are manually read by a meter reader.

Figure 9: Breakdown of Essential Energy's and retailers' metering responsibilities



Type 5 and 6 meters are maintained until they are replaced with a new smart meter. The services provided for Type 5 and 6 meters involve:

- meter maintenance – inspecting and testing
- meter reading – quarterly or other regular reading
- meter data services – collecting, processing, storing and delivering metering data and managing relevant National Metering Identifier (NMI) standing data, in accordance with the NER.

The capital cost of Type 5 and 6 metering equipment installed before 1 July 2015 is also able to be recovered.

AEMC recommendation to accelerate installation of smart meters

The AEMC completed its review of the regulatory framework for metering services (the metering review) in August 2023.[15] **The AEMC has recommended that all legacy Type 5 and 6 meters in NEM jurisdictions be replaced with smart meters by 2030.**

[14] AER, Draft decision – Essential Energy distribution determination 2024–29, Attachment 20 – Metering Services, p. 3. Link

[15] AEMC, Final Report – Review of the Regulatory Framework for Metering Services, August 2023. Link

Assuming that the AEMC's decision is reflected in rule changes, we have had to make substantial changes to the proposed legacy metering expenditure and revenue forecasts we provided in our Proposal.

Many aspects of the implementation of the smart meter replacement program remain to be developed. However, in redeveloping our metering expenditure case, we have assumed that the following elements of the AEMC's recommendations will apply.

Legacy meter retirement plan

Essential Energy will consult with key stakeholders to develop a LMRP. This will provide a proposed annual schedule of meter retirements in our network area from 1 July 2025 to ensure the progressive retirement of the legacy meter fleet.

We note the AEMC's expectation that:

- meters will be retired in geographic groupings, such as by postcode, zone substation or meter reading route, to ensure maximum efficiency
- approximately 20 per cent (plus or minus 5 per cent) of meters would be replaced each year.

The AER will review and approve LMRPs, which must be submitted in draft form by late 2024 to early 2025.

Retailers and their metering service providers will be responsible for replacing meters within 12 months of the meter being retired under the LMRP. Retailers may apply to amend the LMRP over the acceleration period; e.g. if there are material changes in circumstance.

Customers unable to opt out, but not forced to remediate site defects

The current provisions in standard retail contracts that allow customers to opt out of receiving a smart meter will be removed.

While customers will not be able to opt out, remediation issues are a practical barrier to meter replacement. Some customer sites will have defects (such as problems with the panel, wiring or asbestos) that will need to be fixed before a smart meter can be installed. We estimate that in our network area around 30 per cent of sites are likely to require remediation. This is higher than the AEMC's estimate of 10 per cent.

Customers are largely responsible for site remediation costs, but the AEMC has recommended that customers not be forced to remediate defects. In practice, unless funding is provided to customers (e.g. government funding), this is likely to slow down the pace at which legacy meters are replaced. The AEMC has therefore recognised that while the industry should aim to replace all legacy meters by 2030, it may not be possible to do so. If the work is not completed by this date, clarity is needed about ongoing metering responsibilities and cost recovery for legacy metering services.

Basic data on power quality to be made available to DNSPs

DNSPs would be provided with basic power quality data at no cost. A definition of 'basic' has not yet been established.

Exemptions from testing and inspection of legacy meters during the acceleration period

During the acceleration period (when smart meters are being installed), DNSPs will not be required to undertake the usual periodic testing and inspection of legacy meters.

AER's Draft Decision regulatory changes adopted

In its Draft Decision on metering services and subsequent guidance[16], the AER noted that the AEMC's decision makes it necessary to change the regulatory settings for metering.

We have adopted the following proposed changes:

- **Standard control service classification:** The classification for legacy metering services will change from ACS to SCS to manage customer price impacts during the accelerated transition to smart meters (for more information, see **Chapter 6** and **Attachment 6.01**).
- **Accelerated depreciation of the metering asset base:** Reflecting the accelerated transition, the legacy metering asset base will be fully depreciated in the 2024–29 regulatory period.
- **No incentive schemes apply:** The legacy metering component of SCS will be excluded from all incentive scheme considerations, including from the EBSS and CESS.

[16] AER, Legacy metering services – Guidance note, November 2023 Link

Implications and issues specific to Essential Energy

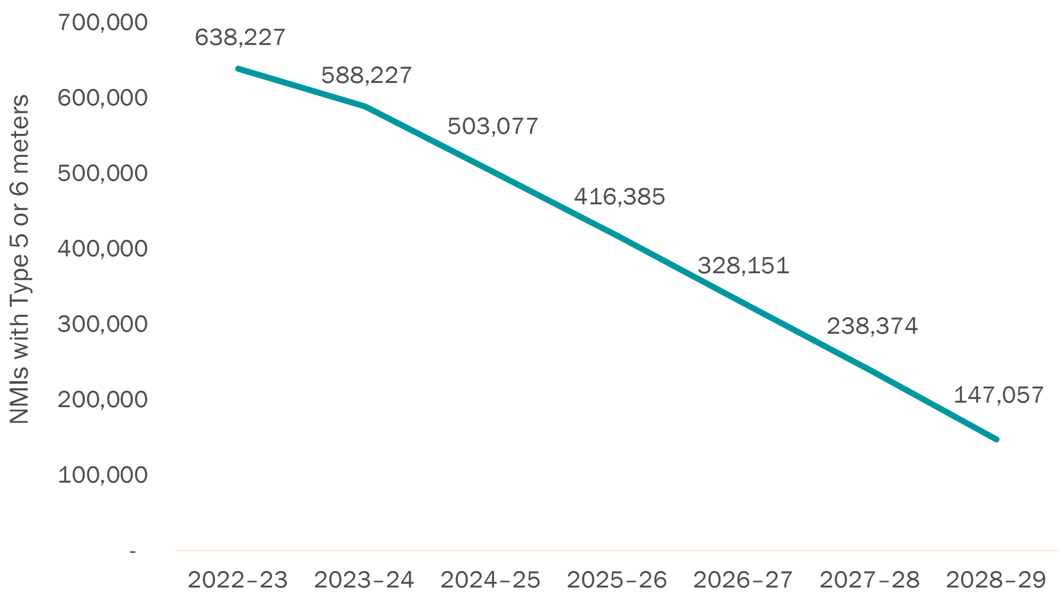
Smart meter deployment rates

The AEMC aims to have all legacy meters replaced by 2030. Achieving this target would mean replacing 90 per cent of legacy meters in the 2024–29 regulatory period. In its guidance on legacy metering services[17], the AER advises that it is appropriate for each distributor to provide a forecast of meter volumes that reflect its expectation about the rate of smart meter deployment and the number of remaining meters it will be required to operate.

Figure 10 shows Essential Energy's forecast meter replacement rate. It includes an assumption that 75 per cent of legacy meters in place on 30 June 2024 will be replaced during the 2024–29 regulatory period. This will leave just over 147,000 meters at the end of the regulatory period.

The forecast meter volumes reflect the metering expenditure forecasts in this Revised Proposal.

Figure 10: Forecast NMIs for Type 5 and 6 meters

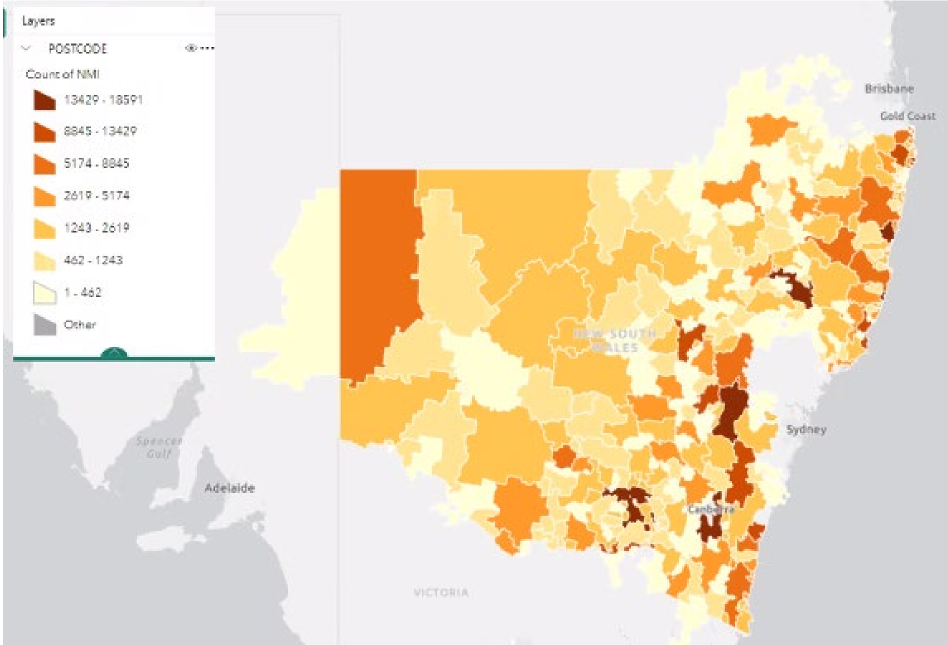


We consider this forecast to be realistic for our network. It reflects network characteristics, market capabilities and other limitations. Key factors that will pose challenges that are likely to reduce the replacement rate in our network area in the 2024–29 period include:

- lower customer density and a greater number of remote customer sites (Figure 11 shows the low density of NMIs over large parts of the Essential Energy network)
- a higher ratio of sites requiring remediation (currently, if a meter board or box requires remediation, meter replacement is delayed or often not completed; 33 per cent or around 80,000 of notified failed legacy meters in our network have site remediation issues and are yet to be replaced)
- lower socio-economic demographics, which means a higher proportion of customers are unlikely to fund their own site remediation for smart meter replacement
- a larger proportion of pole-mounted meter boxes, which are more complex and costly to replace.

[17] AER, Legacy metering services – Guidance note, November 2023, p.3. Link

Figure 11: Number of NMIs across our network



Expenditure impacts

The proposed meter replacement program and its management will have a range of expenditure impacts for Essential Energy in the 2019–24 regulatory period and the 2024–29 regulatory period.

Impacts that will increase expenditure include:

- preparing and managing the LMRP, with costs for:
  - project staff – most likely a project manager and business analyst
  - stakeholder engagement – additional time, travel and other expenses for engagement staff
  - legal costs
  - site visitation costs
- additional meter validations and/or exceptions
- additional meter transfers
- additional meter data storage and handling
- meter site remediation costs, which will be the responsibility of Essential Energy (rather than customers).

Impacts that will reduce expenditure include:

- suspending the inspection and testing of legacy meters, in accordance with the AEMC's decision. The AEMC recommends exempting regular testing and inspection requirements for legacy meters once the AER approves the legacy meter retirement plan. The time-limited exemption would only apply to legacy meters for the five years of the acceleration period. If legacy meters are not replaced in this time, as required under the LMRP, testing and inspection requirements will be reinstated after the acceleration period ends
- a reduction in manual meter reading costs, noting that a significant proportion of these costs are fixed, so they do not fall as meter volumes decline.

With the exception of meter site remediation costs, we should be able to absorb the net impact of the above activities within the forecast metering expenditure allowance.

For meter site remediation costs that are our responsibility, we propose an opex step change. The requirement for this step change and the value of the step change are explained below.

Metering revenue requirement

Essential Energy has used the AER's standardised legacy metering models to produce the 2024–29 revenue forecast.

Overview of revenue requirement

The forecast revenue requirement for legacy metering SCS is $265 million (real June 2024).

Table 26: Legacy metering SCS: revenue requirement (smoothed)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Proposed annual revenue	52	53	53	53	54	265
Proposed annual real revenue change	-56.0%	0.0%	0.0%	0.0%	0.0%	

Numbers may not add due to rounding

The building block components of the legacy metering annual revenue requirement are shown in Table 24.

Table 27: Legacy metering SCS: Building block components for our unsmoothed annual revenue requirement ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Return on capital	5	4	3	2	1	15
Return of capital	14	18	18	18	19	87
Operating expenditure	32	35	33	31	24	155
Revenue adjustments	–	–	–	–	–	–
Tax allowance (net)	1	1	1	1	2	7
Total proposed unsmoothed revenues	52	59	55	53	45	264

Numbers may not add up due to rounding

Operating expenditure

Operating costs for Type 5 and 6 metering services is forecast to be $155 million (real June 2024) over the 2024–29 regulatory period. We have forecast these costs using the AER's legacy meter opex model, which uses a base-step-trend model. The 2022–23 financial year is the base year.

Table 28: Proposed legacy metering operating expenditure 2024–29 ($m, real June 2024)

	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Base opex	29	29	29	29	29	146
Trend	-1	-1	-2	-3	-5	-13
Step change	3	7	5	5	0	21
Proposed opex	32	35	33	31	24	155

Numbers may not add up due to rounding

Opex input assumptions

We included the following key assumptions in our opex forecast:

- The smart meter deployment rate is the rate shown in Figure 10. The AER's guidance note includes an annual true-up mechanism to account for variances between the forecast smart deployment rate and the actual deployment rate.
- The base year is 2022–23, with actual audited base year expenditure of $27 million (nominal).
- The economies of scale factor is 24.81 per cent, consistent with the AER's Draft Decision.
- A weighting of 61.12 per cent is applied to volume trends to reflect the portion of costs that are variable and to remove fixed opex from this trend component, consistent with the AER's Draft Decision.

Remediation cost step change included in the opex forecast

The AER's guidance on legacy metering services[18] acknowledges that remediation costs may be incurred for "works on the distributor side" that can be included with the opex forecast.

We propose a step change of $21 million (real June 2024) over the 2024–29 regulatory period for meter remediation works. Essential Energy, rather than customers, would need to provide three types of meter remediation works that involve distribution network equipment. It would not be appropriate or efficient for other parties to perform these works. In addition, they would involve costs that individual customers could not be reasonably expected to pay. The nature of each remediation cost is explained below.

[18] AER, Legacy metering services – Guidance note, November 2023, p. 4. Link

Relocation of meter boxes on poles

In Essential Energy's network area, over 46,000 meter boxes are mounted on distribution network poles. A proportion of the meter boxes will require remediation as part of a smart meter installation. In most cases, customers will be responsible for meeting this remediation cost.

However, we will have to undertake the remediation work on a small number of high-risk sites that also involve relocating the meter box. It is estimated that these sites represent 2 per cent of the 46,000 boxes on poles.

At these sites, the meter box is mounted on a conductive pole that supports additional network assets, which can include single wire earth return lines, a distribution substation or reactor (or a combination of these). These configurations present a high-risk environment where only the network business can undertake the necessary works.

Current transformers on cross arms

In a very small number of legacy metering installations, current transformers (CTs) that form part of the metering installation are located on the cross arms of Essential Energy–owned poles. Their location means the metering provider for the smart meter would not be able to conduct the regulated testing requirements.

For these installations, CTs will need to be relocated. It would not be efficient for other parties to perform these works, nor appropriate to expect customers to fund these works given the disproportionately high costs.

Single-phase metering on multiphase sites

A very small number of legacy sites have multiphase services that are metered on a single phase, with the meter reading multiplied by the number of phases. This metering configuration is non-compliant. When a smart meter is installed, all phases must be run to and from the meter to comply with the current metrology requirements.

We propose to undertake the works to reconfigure these few, more complex sites.

Capital expenditure

While we haven't included forecast capex relating specifically to meters, some indirect capital will relate to non-system assets. This forecast expenditure is shown in Table 26.

Table 29: Forecast capital expenditure ($m, real June 2024)

$m, real June 2024	2024–25	2025–26	2026–27	2027–28	2028–29	Total 2024–29
Capital expenditure	4	4	3	3	2	16

Numbers may not add up due to rounding

Tax allowance

While we have adopted accelerated depreciation of the metering asset base, we have not adopted accelerated depreciation of the tax asset base. The existing life for tax is used to derive tax depreciation, which is then used to derive taxable income, tax payable and therefore the tax allowance. As it is standard tax practice to fix tax lives once they enter the tax asset base, a business would not revise the tax depreciation of the assets. Reducing the tax remaining life for the opening tax asset base does not align with standard Australian Taxation Office (ATO) treatment, regulatory principles or regulatory precedent. We have therefore adopted the tax depreciation calculated in the roll forward model depreciation tracking module, using year-by-year depreciation tracking.

A separate but related change to the tax allowance is changing the diminishing value multiplier from 200 per cent to 100 per cent. Although this deviates from the ATO definition, this is to ensure that the tax depreciation of the new capital expenditure is correctly depreciated. As part of adopting the accelerated depreciation, the tax standard life applied to future assets is to be reduced to one year. Changing the multiplier manually adjusts the tax depreciation profile for the new tax asset to fully depreciated in the following year to the year in which capital expenditure is incurred.

Potential requirement for cost pass through

If decisions are made that impose additional obligations and costs on Essential Energy to deliver the smart meter deployment program, we may be required to submit a cost pass through application relating to the meter replacement program.

Decisions regarding these obligations may be made as a result of changing the rules to implement the AEMC's decision, or as a result of the associated implementation arrangements.

12

Glossary

Term	Meaning
2019–24 regulatory period	The regulatory control period beginning 1 July 2019 and ending 30 June 2024
2024–29 regulatory period	The regulatory control period beginning 1 July 2024 and ending 30 June 2029
ACS	Alternative control services – specific user-requested services; public lighting; Type 5 and Type 6 metering (generally residential and small business customer meters); and ancillary network services
aggregator	A business that groups and coordinates the exports of individual electricity customers to form a single entity that can engage in the electricity market
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator – the economic regulator for our distribution business
ASP	Accredited service provider
augex	Augmentation capital expenditure
basic meter	Older meters that can only measure the total amount of consumption between manual meter reads (Type 6)
capex	Capital expenditure – funds used to buy or upgrade physical assets such as power poles and buildings
CER	Consumer energy resources – decentralised small-scale local energy generation, located 'behind the meter' of a customer
CESS	Capital Expenditure Sharing Scheme
charging parameters	The specific charging characteristics of a component within the pricing structure
composite pole	A power pole constructed from glass fibre, fire-retardant resin with a UV and fire-retardant coating. Compared to traditional timber poles, they are fire resistant, last longer and offer better protection against termites and corrosion
controlled load	A tariff used with certain appliances that can have the supply of electricity limited in peak times – separately metered
CPI	Consumer price index – a measure of inflation
CSIS	Customer Service Incentive Scheme
customer class	A group of customers who have common characteristics that allow them to be grouped together to ensure similar customers pay similar charges
demand charge	The charge based on the maximum amount of electricity a customer uses at any one time – measured in kW
DER	Distributed energy resources – decentralised local energy generation, which is a broad term that encompasses: > generation often located 'behind the meter' of a customer, now referred to as consumer energy resources (CER) > large-scale generation, such as solar farms and grid-scale batteries > our non-network solutions, such a regulated SAPS and microgrids
direct control services	Services regulated by the Australian Energy Regulator under the National Electricity Rules, comprising standard control services and alternative control services
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DOE	Dynamic operating envelope – variable limits that can be set on a customer's CER installation for their consumption and export of electricity, and which can be varied according to network capacity at the time
DUoS	Distribution Use of System – a charge for using the distribution network
EBSS	Efficiency Benefit Sharing Scheme
Essential People's Panel	A representative group of Essential Energy residential and small business customers from across our network area, who we engage with on a range of business matters, including our Proposal

Term	Meaning
EV	Electric vehicle
export services	A new category of distribution services to facilitate customer electricity exports
F&A	Framework and Approach (paper)
flexible connection agreement	An upcoming change compared to our standard connection agreement. It will reflect how exporting capacity can be shared by customers exporting excess generation
GSL	Guaranteed Service Level – outage threshold levels specified in our Licence Conditions. Customers may be eligible for a GSL payment if the number of, or the duration of, outages they experience are higher than the GSL level specified
HV	High voltage
IAP2	International Association of Public Participation – formal framework to advance and extend public engagement
ICT	Information and communications technology
interval meter	A meter that can record consumption in half-hourly intervals but needs to be read manually (type 5)
IPART	Independent Pricing and Regulatory Tribunal of NSW
kVA	Kilovolt ampere
kW	Kilowatt
kWh	Kilowatt hour
LED	Light-emitting diodes – semiconductor devices that produce light when an electrical current passes through them
licence conditions	A legislated document that sets out the required conditions under which we must operate the network. IPART monitor compliance against the conditions
load	The demand for electricity on the network
LRMC	Long run marginal cost – the cost of adding one more unit of demand to the network
LV	Low voltage
microgrid	A local energy grid that is connected to the traditional grid but can operate independently, with customers exchanging energy locally
MWh	Megawatt hour – unit of energy equivalent to 1,000 kilowatt hours
NEM	National Electricity Market
NER	The National Electricity Rules that govern the operation of the National Electricity Market
nominal	Dollars after factoring in inflation
NUoS	Network Use of System – the charge for using our distribution network, as well as transmission-related pass through costs and jurisdictional scheme costs, such as the Climate Change Fund
opex	Operating expenditure – funds to inspect, maintain and operate our network
outage	A planned or unplanned loss of electricity service – also known as a 'supply interruption'
PCC	Pricing Collaboration Collective – a group of involved and diverse stakeholders who we engaged with on pricing-related matters and who represent the interests of our customers
peak demand/load	The maximum electricity demand customers place on the electricity network
Peak exports/minimum load	When exports are greatest but not enough of that energy is being used
price cap	The maximum price we can charge customers, as set by the Australian Energy Regulator
pricing components	The combination of elements – including network access, and consumption and demand charges – that reflect the efficient costs of providing network services to customers
pricing schedule	An annually published list of prices and pricing structures for each network charge – also referred to as the 'Network Price List and Explanatory Notes'

Term	Meaning
pricing structure	The combination of pricing components that make up the network charge
Proposal	Our Regulatory Proposal for the 2024–29 regulatory period, submitted under clause 6.8 of the National Electricity Rules
PV	Photovoltaic – solar energy
RAB	Regulatory asset base – the regulatory value of the assets we use to provide distribution services
real	Dollars before factoring in inflation, for example 'real $2023–24' means dollars in equivalent terms before inflation is added – when added it is 'nominal'
regulatory allowance	The Australian Energy Regulator's decision on cost components of our Regulatory Proposal
repex	Replacement capital expenditure
return on capital	Return on investment generated for the funds (capital) invested – used to fund repayment of debt and measure profitability
revenue cap	The maximum revenue the Australian Energy Regulator allows us to collect in each year of the regulatory period
Revised Proposal	Our Revised Regulatory Proposal for the 2024–29 regulatory period, submitted under clause 6.8 of the National Electricity Rules
REZ	Renewable Energy Zone
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPS	Stand-alone power system – a local energy system that is not physically connected to the traditional grid but is powered from one or more alternative sources, such as a solar photovoltaic system, wind turbines or engine generators. It is usually made up of a combination of solar panels with a battery and a diesel generator as back-up
SCC	Stakeholder Collaboration Collective – a group of engaged and diverse stakeholders who represent the interests of our customers, which are our primary reference group for the Proposal
SCS	Standard control services – our core activities for enabling customers to access our network and for supplying them with electricity
SLUoS	Street Lighting Use of System – charges for capital recovery (for public lighting installations initially funded by Essential Energy) and maintenance (operating expenditure) of all public lighting installations
smart meter	A digital device that measures and records a customer's electricity usage and their maximum demand every half hour and transmits the data to their electricity provider (Type 1–4)
smoothed revenue	A method that smooths out fluctuations in forecast expected revenue
solar farm	A large-scale solar photovoltaic project, which may be connected to the grid
STPIS	Service Target Performance Incentive Scheme – the Australian Energy Regulator's financial incentive scheme for rewarding or penalising transmission and distribution network service providers for reliability and customer service outcomes
Sun Soaker	A modern take on the traditional Time of Use Tariff, which aims to encourage customers to use more power during peak solar PV export times (between 10am and 3pm) and less at other times (7–9am and 5–8pm). It can help manage both evening peak demand issues on the network and power quality issues from increasing levels of solar PV exports
tariff class	A group of customers who have similar characteristics and who pay similar prices
ToU	Time of Use – a meter or charging parameter that varies according to whether electricity is consumed in a peak, shoulder or off-peak period
TSS	Tariff Structure Statement
TUoS	Transmission Use of System – charges for using the transmission network that are a component of NUoS charges (see NUoS)
two-way pricing	Two-way prices charge for both consumption and exports

Appendix A – Responses

Chapter summary

– We include a summary of all responses in our Revised Proposal.

Summary of responses to AER Draft Decision

Table 27 provides a summary of our responses in this Revised Proposal to each aspect of the AER's Draft Decision.

Where we refer to application of 'standard updates' in Table 27, this means for things such as actual or forecast inflation and/or to reflect the most recent actual/forecast operating and capital expenditure for 2019–24. Further details are included in the relevant chapters.

Table 30: Summary of our responses to each aspect of the AER's Draft Decision

Chapter and elements	AER Draft Decision	Revised Proposal response
Chapter 2 – Customer engagement	Recognised the breadth and comprehensiveness of our consultation and that we demonstrated a genuine feedback loop from customers	We continued to engage with our customers and stakeholders throughout 2023 to reflect their feedback in this Revised Proposal
Chapter 3 – Revenue requirements **Annual revenue requirement (ARR)** **Regulatory Asset Base (RAB)** **Rate of Return (RoR)** **Depreciation** **Corporate income tax** **CESS** **DMIAM/DMIS** **EBSS**	ARR – rejected and updates made for changes in building blocks RAB – rejected and updates made for inflation RoR & expected inflation – rejected and updated estimates made and application of the final 2022 Rate of Return Instrument. Accepted averaging periods proposed. Accepted debt raising costs Depreciation rejected and updates made for inflation and changes in some new asset classes. Accepted straight line depreciation method and weighted average remaining life approach Tax rejected and updates made for changes in other building blocks. Accepted no immediate expensing of forecast capex, continuation of current approaches to tax depreciation for asset classes, and tax asset lives CESS rejected and updated DMIAM/DMIS – continue to apply EBSS rejected and updated	Accept all components with standard updates, and to reflect metering moving into standard control Provided further rationale on why the EBSS penalty from 2019–24 should not be applied mechanistically (**Attachment 3.07**)
Chapter 4 – Network of the future and Resilience **SAPS**	Accepted for opex, and capex provisionally accepted subject to further detail on the SAPS program	Provided additional information on our SAPS expenditure as required by the AER (**Attachment 4.01**), and further information in support of some programs that the AER was less sure about
Chapter 5 – Future challenges	N/A	Further information provided to highlight likely risks over the next five years and challenges with the existing regulatory frameworks
Chapter 6 – Framework & Approach **Classification of services** **Control mechanisms**	Accepted Classification of Services Control mechanisms - accepted CSIS – accepted to apply subject to updated data and final engagement	Classification of Services - amendments due to material changes in circumstances, for metering and other foreseen government interventions. Updates made for simplifications and clarity (**Attachment 6.01**)

CSIS **STPIS** **Pass through events** **Negotiated services framework** **DMIAM/DMIS**	STPIS – accepted with adjustment for reliability improvement (from resilience) and without customer service component Pass through events – accepted existing events, rejected major cyber and definition changes Negotiated services acceptable DMIAM/DMIS – continue to apply	Control mechanisms accepted – the changes for metering are reflected in **Chapter 11** CSIS – accepted with updates for recent data and customer feedback STPIS – accepted Pass through events accepted with addition of new nominated pass through event for bushfire risk reclassification Negotiated services – accepted DMIAM/DMIS – accepted
Chapter 7 – Operating expenditure	Accepted opex	Accept with standard updates (plus base year adjustment for SaaS) and include metering
Chapter 8 – Capital expenditure **Connection Policy**	Accepted capex subject to further information being provided on the SAPS program Connection Policy rejected and amendments made	Accept capex and include metering Further information on our SAPS program is provided in **Chapter 4** and **Attachment 4.01** Further updates made to our Connection Policy in **Attachment 8.02**, to include SAPS and reflect recent engagement – see **Attachments 2.02 and 2.04**
Chapter 9 – Pricing **Tariff Structure Statement**	Not approved Most elements accepted with some suggestions for improvements Rejected rebate applying to HV connected batteries, approach to individually calculated tariffs, and for new Sun Soaker tariff assignment	Accepted with additional information and updates to those items of AER concern, and following additional engagement Changes made to reflect metering moving into standard control Revised TSS and Revised TSES are found in **Attachments 9.01 and 9.02**
Chapter 10 – Alternative control services **ANS** **Public lighting**	ANS - Accepts price cap, some labour rates. Rejects some labour rates, labour price growth. For fee-based services rejects overhead rates, margins, tax allowance, times for special meter tests and assumptions for access permits. Updates made including for inflation. Public lighting – rejected and top down cut applied, pending further engagement	ANS – most items accepted with minor updates to escalators, inflation, material on-costs. Rejected special meter test. Some new fees added and changes to access permits (**Attachments 10-01 to 10.04**) Public lighting – rejected and updates made following further engagement (**Attachments 10.05 and 10.06**)
Chapter 11 – Metering services	Rejected – updates made reflecting expectations of accelerated roll-out of smart meters from the AEMC metering review. Changes to accelerate depreciation.	Changes made to forecasts, costs and control mechanisms for moving legacy metering into standard control.