Reset RIN Response

2024-29 Regulatory Proposal

Endeavour Energy

POWER together

Contents

Purpose

The Australian Energy Regulator (AER) requires Endeavour Energy to prepare and provide the supporting information specified in Sections 4, 5 and 6 of the Reset Regulatory Information Notice (RIN). The Reset RIN was issued to Endeavour Energy under Part 3, Division 4 of the NEL.

This document is Endeavour Energy's response to the information sought in Section 4: Supporting information requirements.

Section 4: Supporting information requirements

4.1 Requirement to provide supporting information under this notice

4.1.1 Endeavour Energy must prepare and provide the AER with the supporting information set out in sections 4, 5 and 6 of this notice.

This document reflects the supporting information required set out in section 4 of the Reset RIN. In relation to the requirements of sections 5 and 6 of the Reset RIN, refer to:

- Endeavour Energy - RIN0.06 Reset RIN Basis of Preparation - January 2023 – Public
- Endeavour Energy - EY - RIN0.07 Reset RIN Audit Report - January 2023 – Public
- Endeavour Energy - RIN0.08 Reset RIN Statutory Declaration - January 2023 - Public

4.2 Information used for the purposes of preparing the regulatory proposal

Consultant reports, material assumptions, etc

4.2.1 Provide information used for the purposes of preparing the regulatory proposal including:

(a) all consultants' reports commissioned and relied upon in whole or in part;

All consultants' reports commissioned and relied upon in whole or in part in the preparation of the Regulatory Proposal are provided in the supporting attachments to our proposal and this RIN. Refer to Endeavour Energy – RIN1.02 Document Register – January 2023 – Public

(b) all material assumptions relied upon;

Refer to Endeavour Energy - 0.08 Certified Key Assumptions - January 2023 – Public

(c) a table that references each response to this section 4 and where it is provided in or as part of the regulatory proposal;

Endeavour Energy – RIN1.01 Response Reference List – January 2023 – Public references each response to a paragraph in section 4 and where it is provided in or as part of the Regulatory Proposal.

(d) a table that references each document provided in or as part of the regulatory proposal and its relationship to other documents provided; and

Endeavour Energy has provided in table form, each document used in or as part of the Regulatory Proposal and its relationship to other documents provided. Refer to Endeavour Energy – RIN1.02 Document Register – January 2023 – Public.

(e) each document identified in the table referred to in section 4.2.1(d) must be given a meaningful filename in the form:

Endeavour Energy – [Author] – [title] – [date] – [public/confidential], where:

(i) Author is the author of the file if not Endeavour Energy for example a consultant or other third party;

(ii) Title provides a meaningful description of the content of document, with limited reliance on acronyms or cross references, for example “Appendix 1A” is not meaningful, but “Appendix 1A – Cost allocation method” is;

(iii) Date is a relevant date associated with the file, generally the date the document was created, received or finalised;

(iv) Public/confidential identifies if the file in its entirety can be published (public); or if it contains any information which is the subject of a claim for confidentiality in accordance with this notice (confidential).

In referencing the documents as requested in 1.4(d), Endeavour Energy has provided each document with a meaningful filename by adopting the Endeavour Energy – [Author] – [title] – [date] – [public/confidential] form.

4.2.2 For each material assumption identified in response to section 4.2.1(b) provide:

(a) its source or basis;

(b) if applicable, its quantum;

(c) whether and how the assumption has been applied and was taken into account; and

(d) the effect or impact of the assumption on the capital and opex forecasts in the forthcoming regulatory control period taking into account:

(i) the actual expenditure incurred during the current regulatory control period; and

(ii) the sensitivity of the forecast expenditure to the assumption.

The below material assumptions are included in Endeavour Energy - 0.08 Certified Key Assumptions - January 2023 - Public

Structure & ownership

This assumption provides clarity that our capex and opex forecasts have been prepared based on current ownership and legal structure and do not incorporate any impacts associated with a potential change of ownership.

Our organisational structure has also been important in providing strategic input into the objectives that have underscored the development of our capex and opex proposals. This includes our continued focus on efficiency and service quality, most recently promoted through our ICT & Digital transformation program. This has been instrumental in deriving cost savings that have been incorporated in our forecast capex and opex, and which have enabled us to meet our objectives of customer affordability while maintaining safety and reliability of the network.

Compliance requirements

This is a key assumption underpinning our asset management framework and forecasts of reliability and ICT compliance capex.

As a holder of a licence to operate a distribution system in NSW, Endeavour Energy is required to meet several ministerially imposed Licence Conditions primarily relating to supply reliability and network performance. These conditions are in place to ensure customers are provided with an adequate level of service and security. Meeting these obligations is a key assumption underpinning our forecasts of capacity, ICT and reliability compliance capex.

Our capex forecasts have been prepared on the basis of achieving compliance with the NSW Licence Conditions in place at the time forecasts are finalised. We do not believe that there will be a change in

Licence Conditions between now and the forthcoming regulatory control period (beyond that already determined in September 2022)[1] and we consider it is reasonable to conclude that current licence conditions will be in place for the entirety of the 2024-29 regulatory control period.

In the event that a change is made to the Licence Conditions in the 2024-29 regulatory control period and requires a material increase in capex to achieve compliance, these may be recoverable through the pass-through provisions provided in the NER under a regulatory change or service standard event.

Endeavour Energy's proposed reliability compliance capex comprises the required investments to comply with Schedule 3 (which relate to individual feeder reliability) of the licence conditions. Endeavour Energy's proposed OT and ICT capex includes the required investment to comply with the critical infrastructure licence conditions.

Service classification

This assumption confirms that our capex and opex forecasts relate only to the distribution services we are allowed to provide as outlined by the approved service classification in the AER's final Framework and Approach (F&A) paper.

We have not proposed any change to the scope of services or form of regulation to apply to these services from the final F&A paper. In other words, our opex and capex forecasts reflect the efficient cost of providing only the services regulated as standard control services in the F&A paper.

Stakeholder and customer engagement

Our engagement activities have been a key input in the development of our Regulatory Proposal. We have long recognised that genuine and quality engagement is key in ensuring we can reflect customer priorities in our investment decisions and expenditure forecasts.

During the current regulatory control period, the AER published its Better Resets Handbook which sought to further encourage networks to engage meaningfully with customers and stakeholders and ensure consumer preferences drive the development of regulatory proposals. Notably, the handbook sets out the AER's expectations on the nature, breadth and depth of engagement that would support a quality Regulatory Proposal and allow for a more streamlined assessment process. We have applied the principles of the handbook in developing our Regulatory Proposal.

Our pre-lodgement engagement program which supports the customer-centric objectives of the handbook has been co-designed with our Regulatory Reference Group (RRG), which includes an independent panel of experts representing a diverse set of stakeholder views. Our Regulatory Proposal has been heavily influenced by broad and deep engagement with our customers and stakeholders over the last few years.

We have utilised a wide variety of engagement methods and channels to ensure the overall regulatory engagement program achieves both deep and broad engagement with a diverse cross-section of customers and stakeholders. Furthermore, we have been continuously engaging with the AER and submitting information at regular intervals as part of the Early Signal Pathway that is offered to networks preparing their regulatory proposals within the Better Resets Handbook framework.

The findings of our customer engagement activities support the key objectives of our Regulatory Proposal and resultant expenditure forecasts and service outcomes demonstrate that our proposal is reasonable and accords with customer and stakeholder expectations.

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[1] Refer to Endeavour Energy licence as varied by 23 September 2022 Minister's variation (link)

Chapter 5 of our Regulatory Proposal provides further information on our customer engagement activities. For our Engagement plan and details of the activities we undertook in engaging customers and stakeholders, refer to:

- Endeavour Energy - 5.01 Engagement Summary Report - October 2022 – Public
- Endeavour Energy - 5.04 Engagement Plan (Plain Language) - April 2022 – Public

Service reliability

This assumption provides clarity that the capex and opex forecasts are the efficient amounts required to maintain the overall level of service reliability as measured by network average normalised SAIFI and SAIDI measures.

Through our engagement activities we tested customer and stakeholder preferences over changes in service reliability performance and the consequential cost impact. In considering the service/cost trade-off, the majority of respondents revealed a desire to maintain the current level of service reliability performance. Subsequently, we have developed our forecasts with a view to broadly continue delivering customers the existing levels of reliability.

Cognisant of the impacts the 2019-20 bushfires and multiple flooding events in 2020, 2021 and 2022 had on our network, we also engaged with stakeholders on the issue of network resilience. Although related to reliability, resilience relates to the ability of the network to anticipate, withstand, quickly recover, and learn from major disruptive events. In understanding the distinction between these two concepts, it is important to recognise improving reliability will not necessarily improve resilience.

Stakeholders expressed a preference for improving the resilience of the most vulnerable locations of our network and therefore, unlike reliability, our capex proposal includes expenditure to improve network resilience.

Asset management

Endeavour Energy utilises an investment framework that applies a risk-based approach to economic benefits quantification. The framework includes an optimisation process that reveals the combination of investments and timing for expenditure that will lead to the highest overall NPV for the portfolio being achieved over the 2024-29 regulatory control period. Critically, our approach to capital investment aligns with the relevant guidance notes and guidelines published by the AER which set out the principles, approaches and expectations of DNSPs needed to support efficient network investment decision making[2].

Our investment planning process commences with the development of individual plans in the key network investment areas which are supported by detailed analysis that explicitly takes into account:

- externally imposed obligations and requirements including service standards, design standards, safety and environmental obligations, and specific asset performance targets;
- information about the network system including loading, condition of assets, performance variability, current capacity, age and the criticality of key assets;
- forecasts of demand growth and connections by location; and
- inputs obtained from stakeholder engagements.

[2] This includes but is not limited to the: Expenditure Forecasting Assessment Guideline, Asset replacement application note, DER integration expenditure guidance note, Non-network ICT capex assessment approach and Network resilience note.

To optimise the mix of investments needed to manage the competing constraints on our network, we apply our Investment Decision Support Tool (IDST) which is a key component of our customer Value Framework. This framework ensures approval to undertake capital works is granted based on merit (i.e. NPV positive benefit) according to the risks placed on our network by current and impending constraints. Where appropriate, our cost-benefit analysis applies the AER's VCR and CECV as part of the broader VaDER framework to value CER enabling investment.

In conjunction with our gated governance process, our framework ensures our capital programs are targeted, economically justified and continuously monitored through to the post-delivery stage. Our optimisation process also aims to identify prudent opportunities to defer or avoid capital expenditure based on an assessment of relative risk such that we could minimise our requirement for investment funding and better meet our goal of customer affordability.

The optimised outcomes produces a program of works which reflects a prudent assessment of risks to achieve our objective of customer value. In this respect, the reasonableness can be demonstrated by the value framework used to rank the relative economic costs and benefits of the program that is cognisant of the priorities of our customers. This enabled us to prudently select programs that could be efficiently deferred.

Growth capex

This is a key assumption underpinning our capacity related capex and opex trend factor. Information on our demand and customer numbers forecasting methodology and outcomes can be found in Chapter 7 of our Regulatory Proposal.

Peak demand forecasts set out the expected increase in peak demand on locations of our network, while customer connections record the increase in the number of residential and non-residential customers on our network.

In respect to our peak demand forecasts, we note that:

- Endeavour Energy's method relies on historical peak demand recorded at each zone substation, and this provides an indication of trends in demand growth at different points in the network. Importantly, our forecast process is capable of excluding spot loads from trend growth, considering new connections in the short term and weather correcting;
- the impact of CER growth is reflected in post-modelling adjustments. Our demand forecast is a net figure of customer demand and embedded generation accounting for both self-consumption and local re-consumption; and
- in developing our capex forecasts for the 2024-29 period, we have applied our methodology using most recent available historic data.

Our customer growth forecasts have relied on historical estimates and take into account evidence on changes from historical levels. We also have regard to growth rate projections from an expert third-party macroeconomic forecaster and assess the reasonableness of our model outcomes against comparable, independent forecasts of growth activity in our network.

Replacement capex

This is a key assumption underpinning the efficiency and prudency our repex forecast. By confirming that we have referred to the guidance provided in the AER's *Asset replacement industry practice application note*, we consider that our repex forecast accords with good asset management and risk management practices, supports sound asset retirement planning, and are generally consistent with what the AER has considered prudent and efficient in previous decisions. For details on our repex forecast, refer to section 10.5.3 of our Regulatory Proposal.

For detailed information on our methodology for assessing condition-based risk to our system assets and for estimating risk cost and detailing how risk is used to make asset retirement, de-rating, and intervention decisions, refer to Endeavour Energy - 10.22 Asset Risk Model Framework - November 2022 – Public

Furthermore, we have applied the AER's Repex Model in a manner consistent with the *AER repex model outline for electricity distribution determinations*. Appropriate input assumptions and correct calibration of the model also supports our use of this top-down tool to inform an efficient forecast for modelled repex. For further details on the Repex model, refer to Endeavour Energy - Brian Nuttall Consulting - 10.23 AER Repex Model - September 2022 – Public

VCR and VaDER

Our capex forecast is underpinned by proposed programs which for material programs and projects are supported by cost-benefit analysis which applies a value for the service provided by the proposed investment. We have applied the AER's VCR values which reflect the best informed and independent estimates of the value different types of customers place on reliable electricity supply under different conditions and are usually expressed in dollars per kilowatt hour ($/kWh) of unserved energy. Our use of the AER's published VCRs over a subjective, alternative input supports the objectiveness and robustness of our cost-benefit assessments.

Similarly, economic justification for our CER enablement and export related expenditure is supported by the use of the AER's CECVs which reflect some of the wholesale market benefits of greater CER penetration. Other value streams have been estimated applying the VaDER methodology. In applying the VaDER principles, the value of network, environmental and customer benefits from enabling higher levels of distributed renewable generation can be considered where appropriate.

Unit costs

This assumption is pertinent to our capex forecast for the 2024-29 period. The unit rates and project costs applied in developing our capex forecast are representative of the efficient costs that will be incurred in the next regulatory period.

Forecast capex for those major projects that have commenced within 2019-24 and scheduled for completion within the 2024-29 period have been derived directly from a competitive tender process. For the remainder, the historical unit rates used to develop our capex forecast do reflect our extensive use of external resources through our blended delivery model.

Base year

With the exception of debt raising costs, Endeavour Energy's forecast opex is derived using the base year approach under which the actual operating expenditure of the regulatory year 2022-23 is used as the starting point upon which 'change factors' are applied to derive the future opex requirements for the 2024-29 period.

The base year 'revealed cost' base-step-trend method is commonly used by DNSPs and is the AER's preferred method to derive estimates of forecast opex. It is a reasonable method as we consider our 2022-23 opex will be efficient and are largely recurrent. The 2022-23 base year will be the last available year of actual opex by the time the determination is finalised and is therefore the most current estimate of providing standard control services that are of a recurring nature.

By applying the base-step-trend methodology, 2022-23 base year opex is then adjusted to account for future changes in Endeavour Energy's circumstances, operating environment, and changes in demand and cost inputs in arriving at a forecast opex. This is to ensure that all known factors affecting Endeavour Energy's future opex requirements are appropriately accounted for.

We note that the manner in which we have used 2022-23 data as a basis for forecasting is also fit for purpose and reasonable in our circumstances. For example:

- Removing non-recurrent end of year adjustments - Our base year opex also contains year-end adjustments to remove demand management innovation allowance and movements in provisions opex. The removal of these costs is consistent with the excludable categories of opex for EBSS purposes specified by the AER in the 2019-24 determination and the requirements of the NEL.
- Adjustment for accounting changes – Our base opex, for EBSS purposes, has been reported on a consistent accounting basis with the 2019-24 opex allowance. However, there have been within period accounting changes to the treatment of leases and Software as a Service (SaaS) costs. For forecasting purposes our base year opex has been adjusted to bring the regulatory treatment of these costs into alignment with statutory accounting standards for the 2024-29 period.

Further information on why our approach to deriving forecast opex, including the manner in which we have applied 2022-23 data can be found in Chapter 11 of our Regulatory Proposal.

The opex model is provided in Endeavour Energy - 11.01 Opex Model - January 2023 - Public. The opex model incorporates adjustments to made to opex to reflect changes in accounting standards. These adjustments are explained in Endeavour Energy - 8.01 Lease Capitalisation - January 2023 – Public.

Trend factors

This assumption relates to our forecast changes in output growth and productivity which are reasonable and reflect the trend in future opex. The opex model gives effect to the base-step-trend approach of forecasting opex. Revealed efficient opex is 'trended' to account for price changes (labour and material costs), output growth (the size of the network) and productivity gains.

Our forecast change in the opex model's output factors has been informed by a combination of advice from expert independent consultants, historical trends and internal analysis from Endeavour Energy subject matter experts. The weight attributed to the forecast change in output factors for each econometric model have been derived by the AER's opex model.

We have applied a productivity adjustment consistent with the AER's Forecasting productivity growth for electricity distributors final decision paper. For details on our forecasting methodology for growth in customer numbers and demand, refer to section 7 of our Regulatory Proposal.

Price escalation

This assumption is pertinent to our forecast of labour and material price changes and their impact on our opex forecast for the 2024-29 period.

Real cost escalation refers to the movement in the price of labour relative to the Consumer Price Index (CPI). A positive value denotes that the price of labour is expected to increase above CPI. The impact of the value of real cost escalation enables us to estimate the likely cost of undertaking capital works or an opex activity in the year that the work is undertaken.

To ensure that the changes in labour costs appropriately reflect the skills required and the market factors driving the demand and supply of labour, we have adopted the forecast of labour escalation advised by BIS Oxford Economics (BIS). This forecast reflects expected changes in labour costs for the Electricity, Gas, Water and Waste Services (EGWWS) sector in NSW.

We consider that our approach is reasonable for the following reasons:

- BIS Oxford Economics is an expert economic firm with the expertise to provide a reliable forecast, taking into account our industry;
- the method used by BIS (state based WPI of EGWWS) has been the approach the AER has used in recent regulatory determinations; and
- they are benchmark estimates rather than the amounts contained in our Enterprise Bargaining Agreement.

In deriving a value of real cost escalation for labour escalation, Endeavour Energy has proactively also applied the AER's equivalent forecast of real labour costs in the opex model and attributed a 50% weighing to each of the AER's and BIS forecasts. This is change from previous proposals whereby this averaging approach was made by the AER as part of its draft and final opex decisions.

Further information on our labour cost escalation is in Chapter 11 of our Regulatory Proposal. The advice provided by BIS is contained in Endeavour Energy - BIS - 0.10 Real Cost Escalation Forecast - November 2022 – Public.

Inflation

This assumption is pertinent to our opex and capex forecast for the 2024-29 period as well as our proposed revenue requirement. The various models used to establish our maximum revenue requirement requires a forecast of inflation as a critical input.

Our inflation forecasts have been derived by applying the AER's preferred approach as outlined in its *Regulatory treatment of inflation final position paper.* This requires us to have regard to the RBA's outlook on inflation as indicated in the most recent version of the RBA's Statement on Monetary Policy. We have also considered advice provided by the AER to guide a consistent interpretation and approach to inflation calculations across DNSPs submitting a Regulatory Proposal for the 2024-29 period.

Cost allocation

This assumption provides assurance that our capex forecast is consistent with our capitalisation policy and our Cost Allocation Methodology (CAM) which provides the basis for attributing and allocating forecast capex to standard control services, alternative control and other or unregulated services. Our CAM remains unchanged from that in place during the 2019-24 regulatory period and therefore facilitates direct comparison and assessment between expenditures in the current and forecast period.

For further details on our CAM, refer to Endeavour Energy - 0.06 Cost Allocation Method - March 2018 – Public.

Managing uncertainty

This assumption provides clarity and certainty on the type of low probability exogenous events which, if they eventuate, the incremental cost impact can be recovered via the cost pass through and contingent project mechanisms in the NER.

In regard to pass throughs, our forecasts assume the AER will approve the same pass-through events which were approved for the 2019-24 regulatory period. This provides us with assurance that we will not need to apply alternative, less efficient risk management measures for low probability/high risk events such as planning, designing and building network infrastructure to an increased standard to withstand natural disasters or obtaining insurance to cover new risks irrespective of the cost increase or quality of provider.

Should one of our nominated events be triggered during 2024-29, costs are passed through to customers ex-post subject to AER approval. Should the AER not accept our nominated events, the cost of these alternative risk mitigation measures will need to be incorporated in our ex-ante forecasts/allowance and be passed through to customers. For further details on our nominated pass-through events, refer to: Endeavour Energy - 0.11 Pass Through Event Proposal - January 2023 – Public.

In regard to contingent projects, we have not identified any contingent projects for 2024-29.

4.2.3 Provide reconciliation of the capex and opex forecasts provided in the regulatory templates to the proposed capital and operating allowances in the post-tax revenue model for the forthcoming regulatory control period.

Capital and operating expenditure forecasts provided in the regulatory templates of the RIN and in attachments,

- Endeavour Energy - 10.10 SCS Capex Listing - January 2023 – Public
- Endeavour Energy - 11.01 Opex Model - January 2023 – Public

have been reconciled to the proposed capital and operating allowances in the PTRM Endeavour Energy - 0.04 Post-Tax Revenue Model - January 2023 - Public

4.2.4 Where the regulatory proposal varies or departs from the application of any component or parameter of the capital efficiency sharing scheme, efficiency benefit sharing scheme, demand management incentive scheme or service target performance incentive scheme as set out in the framework and approach paper, for each variation or departure explain:

(a) the reasons for the variation or departure, including why it is appropriate;

(b) how the variation or departure aligns with the objectives of the relevant scheme; and

(c) how the proposed variation or departure will impact the operation of the relevant scheme.

Endeavour Energy's Regulatory Proposal does not vary or depart from the application of any component or parameter of the capital efficiency sharing scheme, efficiency benefit sharing scheme, demand management incentive scheme.

With regard to the service target performance incentive scheme (STPIS):

- we propose a small-scale incentive scheme, namely a Customer Service Incentive Scheme (CSIS), in place of the customer service component of the STPIS as contemplated by the AER's final F&A paper. Our proposed CSIS is consistent with the AER's CSIS guideline with details on the scheme design including our proposed service performance parameters for 2024-29 set out in the Endeavour Energy - 9.02 CSIS Proposal - January 2023 – Public; and
- a revised proposed scheme covering changes to the event exclusion methodology for reliability is set out in Endeavour Energy - 10.07 STPIS and non-compliant feeder capex proposal - November 2022 - Public.

Models

4.2.5 Provide the models Endeavour Energy has used to:

(a) develop its total forecast capex;

Refer to Endeavour Energy - 10.10 SCS Capex Listing - January 2023 – Public.

(b) derive and apply the materials price changes, including any model(s) developed by a third party;

Not applicable.

(c) develop total forecast opex;

Refer to Endeavour Energy - 11.01 Opex Model - January 2023 – Public.

(d) develop proposed charges for public lighting services in the forthcoming regulatory control period;

Refer to Endeavour Energy - 14.06 Public Lighting Pricing Model - January 2023 – Public.

(e) forecast new connections and maximum demand;

Refer to Endeavour Energy - 7.05 Customer Forecast Model - December 2022 – Confidential.

(f) calculate the long run marginal cost estimates in Endeavour Energy's proposed tariff structure statement;

Refer to:

- Endeavour Energy - 0.16 Import LRMC model - January 2023 – Public
- Endeavour Energy - 0.17 Export LRMC model - January 2023 – Public.

(g) develop proposed charges for metering services (the AER's Standardised metering capex and opex model; and the Standardised metering pricing model); and

Refer to:

- Endeavour Energy - 14.03 Metering Capex and Opex Model - January 2023 – Public
- Endeavour Energy - 14.04 Metering Pricing Model - January 2023 – Public.

(h) develop proposed charges for ancillary network services (the AER's Standardised ancillary network services model).

Refer to Endeavour Energy - 14.07 ANS Pricing Model - January 2023 – Public.

4.3 Classification of services

4.3.1 If the proposed service classifications in the *regulatory proposal* depart from any of the service classifications set out in the *framework and approach paper*:

(a) provide, in a second set of regulatory templates, all information required in each regulatory template in accordance with the instructions contained therein, modified as necessary, to incorporate the proposed service classifications; and

(b) identify and explain where the regulatory templates differ.

The proposed service classification in Endeavour Energy's Regulatory Proposal does not depart from a service classification set out in the framework and approach paper.

4.4 Capital expenditure

General

4.4.1 Provide justification for Endeavour Energy's total forecast capex, including the following information:

(a) why the total forecast capex is required for Endeavour Energy to achieve each of the objectives in clause 6.5.7(a) of the NER;

The Rules states that Endeavour Energy's forecast capital expenditure must be the expenditure that it considers is needed to achieve each of the outcomes listed in clause 6.5.7(a), known as the 'capital expenditure objectives'. These objectives are[3]:

- meet or manage the expected demand for standard control services (objective 1);
- comply with all applicable regulatory obligations or requirements (objective 2);
- maintain the quality, reliability and security of supply of standard control services and of the distribution system through the supply of standard control services (objective 3); and
- maintain the safety of the distribution system through the supply of standard control services (objective 4).

Objective 1

Our capex program, in particular our augex and connections capex forecast, has been developed to service the expected demand for network services over the regulatory control period. These forecasts are based on the forecast demand and customer connection volumes for the 2024-29 period. Our augex and connections forecasts is outlined in Chapter 10 of our Regulatory Proposal and in more detail in the following supporting attachments:

- Endeavour Energy - 10.10 SCS Capex Listing - January 2023 – Public
- Endeavour Energy - 10.21 Connections Case for Investment - September 2022 – Public.

Our demand, customer connection and energy forecasts and an overview of the methodologies applied are outlined in Chapter 7 of our Regulatory Proposal.

As we are a summer constrained network, our summer demand forecasts are used to inform our investment planning decisions in each region within our network area. These forecasts are provided in Endeavour Energy - 7.01 2023-2032 Summer Demand Forecast - August 2022 – Public. This document also provides further detail on our demand forecasting methodology.

Demand is also impacted by growth in the number of connections. Our forecast customer number growth is derived through the customer forecast model. Refer to Endeavour Energy - 7.05 Customer Forecast Model - December 2022 – Confidential.

Objective 2-4

As a DNSP in NSW we have a large number of obligations stemming from regulations, codes, guidelines, legislation and licence conditions. We provide a full listing of the obligations and requirements we must adhere to in regulatory template 7.3.

Our capex forecast is reflective of these obligations and most significantly impacted by the following obligations:

[3] See clause 6.5.6(a) for exact wording.

- **Our licence conditions:** our ministerially imposed licence conditions cover a range of asset management and performance requirements. These conditions impose planning standards, reliability performance outcomes, asset management practices, etc;
- **Technical regulator:** IPART is our technical regulator and requires substantially increased evidence that our organisation has sound and effective asset management strategies in place. It is now a requirement that the company's Asset Management system and functions comply with the requirements of the international asset management standard ISO 55001 as a NSW Distribution Licence Condition;
- **Electricity Supply Act 1995 (NSW) and Electrical Supply Regulation 2014 (NSW):** these pieces of legislation impose obligations and standards relating to the construction, operation, repair, maintenance and safety of our network, arrangements for the connection of customers and the reliability and security of supply planning and compliance reporting;
- **Safety Codes, Standards and Guidelines:** There are numerous guidelines and standards that Endeavour Energy is required to adopt (in the absence of a better alternative) under legislation such as the Work Health and Safety Act or Electricity Supply Act 1995 (NSW). These include codes such as the National Electricity Network Safety code and various guidelines covering numerous areas of our operations including vegetation management, live line work, fire protection, working on cables, the installation of cables, application of auto-reclosers, design and maintenance of overhead distribution lines, inspection and preservation of wood poles, risk management etc;
- **Property:** in the course of our operations we own, acquire and access a large amount of land within our network area. These activities are governed by several property laws related to Aboriginal land rights, development of land for electrical infrastructure, creation of line easements, remediation of sites, general requirements relating to construction, operation, repair, maintenance and safety, etc; and
- **Environment and planning:** there are several requirements regarding environmental planning, assessment and consultation, handling hazardous materials, heritage considerations, land development requirements and other miscellaneous requirements.

These obligations have a direct consequence on our policies and practices and as a result our capex requirements. Our forecasting process provides assurance of our compliance through developing bottom-up forecasts for key categories of expenditure as a check that the total forecast derived from top-down models reasonably reflects the efficient cost that a prudent operator would need to achieve the opex objectives, based on a realistic expectation of demand forecast and cost inputs.

The supporting capex attachments to our Regulatory Proposal provide further detail of how we consider our obligations in developing capital plans and how we have sought to maintain the quality, reliability, safety and security of supply and the safety of our distribution system. In particular, Endeavour Energy's asset management plans including:

- Endeavour Energy - 10.01 Investment Management Framework (IMF) - November 2022 – Public;
- Endeavour Energy - 10.02 Asset Management Policy - May 2022 – Public;
- Endeavour Energy - 10.03 Network Business Strategy - November 2022 – Public;
- Endeavour Energy - 10.04 Investment Portfolio Decision Making - November 2022 – Public;
- Endeavour Energy - 10.05 Value Framework - November 2022 – Public;
- Endeavour Energy - 10.07 STPIS and non-compliant feeder CAPEX proposal - November 2022 – Public;
- Endeavour Energy - 10.22 Asset Risk Model Framework - November 2022 – Public; and
- Endeavour Energy - 0.07 Expenditure Forecasting Methodology Statement - June 2022 – Public.

(b) how Endeavour Energy's total forecast capex reasonably reflects each of the criteria in clause 6.5.7(c) of the NER;

The AER must accept Endeavour Energy's forecast of required capital expenditure if it is satisfied that the total forecast capital expenditure reasonably reflects each of the capital expenditure criteria, being:

- the efficient costs of achieving the capital expenditure objectives;
- the costs that a prudent operator would require to achieve the capital expenditure objectives; and
- a realistic expectation of the demand forecast, and costs inputs required to achieve the capital expenditure objectives.

Our expenditure forecasting process is based on meeting our regulatory obligations and draws on our expert understanding of our network and the functions we have to perform in our role as a DNSP. Our investment strategies, principles, forecasting process and governance are described in Chapter 10 of our Regulatory Proposal and Endeavour Energy - 0.07 Expenditure Forecasting Methodology Statement - June 2022 - Public. Broadly, we use the AER's top down models as validated by detailed, bottom-up analysis to derive an estimate of our capital requirements which is then subject to a probabilistic, quantified economic cost based optimisation process and robust governance framework.

In terms of demonstrating that our forecasting process is efficient and prudent, our regulatory proposal and supporting capex documents provide evidence to show that:

- we have effective policies and procedures to inform our expenditure decisions and our planning processes;
- our governance processes ensure that expenditure decisions are appropriately delegated and have effective financial controls;
- we have used a fit for purpose forecasting method which ensures there is no overlap or gap in our expenditure requirements, and uses appropriate methods for identifying investment on different parts of our network and network elements; and
- we have a consistent and appropriate method for identifying investment need that takes into account our circumstances, and a rigorous approach for selecting of the most efficient option to address the need.

A key element of our forecasting process is the use of realistic expectation of the demand forecasts and costs inputs, consistent with the capex criteria in the NER. Endeavour Energy's planning process has incorporated accurate and up to date peak demand forecasts as part of the key inputs into developing capital plans. Endeavour Energy records peak demand at each of its 171 zone substation areas and this provides an indication of trends in demand growth at different points in the network. We carry out forecasting process twice per year to ensure our spatial demand growth forecasts are reflective of the progress of greenfield development in Priority Growth Areas across which underpin much of the growth in connections and demand across our network.

Importantly, Endeavour Energy's forecast process is capable of excluding spot loads from trend growth, considering new connections in the short term, incorporating the impact of distributed energy resources and energy efficiency requirements and weather correcting.

In terms of cost estimates, we have used 'fit for purpose' methodologies to derive the costs of undertaking projects or programs of work in each capital plan. Our methodologies take into account historical experience, the specific nature of the program of work, and potential efficiencies that may arise. Our cost estimates have also taken into account expert opinion from economic forecasters on real cost escalation over the 2024-29 period.

The prudency and efficiency of our capex forecast is addressed further in our response to paragraph (c) below.

(c) how Endeavour Energy's total forecast capex accounts for the factors in clause 6.5.7(e) of the NER;

Endeavour Energy's total forecast capex accounts for each of the capex factors. In relation to the factors that relate to the prudency of our forecast (the forecasting process):

- we have considered the substitution possibilities between operating and capital expenditure in developing our forecast expenditure (capex factor 7). A key step in our expenditure forecast process is to consider the full range of alternative options, including areas where there may be opex solutions. Specifically, we have screened our capex program for non-network solutions using our New Technology Master Plan (NTMP) tool. This tool can provide early insight into which capex projects may have the highest likelihood of servicing (i.e. being avoided, reduced in scope or deferred) by a non-network opex option).

  As a result, we have reduced our augex proposal and included an opex step change to recover a portion of the cost of implementing increased demand management solutions. Over the 2024-29 period we will incur additional opex to defer capex where it is efficient to do so (typically determined as part of a RIT-D process) and in consideration of the relevant incentive schemes;

  Another significant interaction between capex and opex relates to replacement capex and maintenance opex. Where assets are replaced more frequently and/or proactively this is likely to reduce maintenance costs as assets are less likely to fail or require as frequent servicing (and vice versa).

  In order to maintain existing reliability levels we propose to maintain existing replacement levels. Our opex forecast is therefore based on existing maintenance practices, specifically the 2022-23 base year which is reflective of sustainable replacement capex levels. Any amendments to our replacement program are likely to have an impact on our required maintenance opex (although the relationship is difficult to quantify).

- Endeavour Energy has considered and made provision for efficient and prudent non-network alternatives (capex factor 10). We have investigated ways to defer augmentation at specific sites of our network when developing our forecasts and have incorporated the expected reduction in system demand from the implementation of new broad based demand management activities. The savings from demand management initiatives have been incorporated into our capex forecasts;

- we have considered the relative prices of operating and capital inputs (capex factor 6). As noted above we have sought to assess all feasible options when addressing a need including opex and capex options. When doing so, we have used best practice methods for deriving the relative cost of opex and capex solutions, and have applied a consistent approach for real cost escalation;

- our forecast process has considered the concerns of electricity consumers as identified during our engagement with electricity consumers (capex factor 5A). We engaged customers on a range of issues, the findings from our customer engagement support the basis of our proposed total capex including in relation to affordability, maintaining current levels of safety and reliability and investing in and trialling new technologies to support customer choice and control in the future and network resilience;

- Endeavour Energy's forecast method considered whether any projects or programs of expenditure should be identified as contingent projects, and therefore excluded from the total forecast capex for standard control services (capex factor 9A). We have not identified any projects that meets the criteria set out in 6.6A.1 of the Rules; and

- At the time of submitting our Regulatory Proposal, final project assessment reports (FPAR) are available for the following projects included in our 2024-29 forecast capex (capex factor 11):

Project	Project Name	2024-29 Capex	FPAR Published
NPR-000025	Aerotropolis 132kV supply	$1.73M	Jan 2022
NTS-000131	Carlingford TS control building	$4.39M	Nov 2021

NPR-000026	Westmead Health Precinct area – Westmead ZS	$12.8M	October 2022
NPR-000021	Supply to Sydney Science Park area	$30.88M	October 2022
NPR-000075	33kV supply to Luddenham and Kemps Creek area (WSA TS)	$0.94M	June 2022
NPR-000079	North Camellia supply (Switching Station)	$0.08M	June 2022

We have addressed the remaining capex factors that we consider may represent partial indicators of the efficient level of capex. In relation to actual and expected capital during any preceding regulatory control periods (capex factor 5), we consider there are two primary considerations that provide a partial check on the total forecast proposed:

- we have identified key variations to forecast capex in the 2019-24 period and consider that these have been taken into account when developing forecasts in the next period. See section 10.4 of the Regulatory Proposal for further details; and
- our forecast capex for 2024-29 is less than the 2019-24 period and can be explained by key changes in our circumstances. In particular the conclusion of our ICT & Digital transformation program and the associated efficiency benefits and our commitment to constraining our capex forecast in providing customers a value for money service.

We note that previous expenditure analysis should be viewed in conjunction with whether the forecast is consistent with any incentive schemes that apply to the DNSP (capex factor 8). During the 2019-24 period the CESS applied to capex providing a strong incentive to prudently and efficiently reduce capex relative to the AER's allowance. Endeavour Energy's actual capex in the 2019-24 period is expected to be lower than forecast[4]. In this respect, customers will benefit from reductions to the RAB.

The incentive regime has played a complementary role in the speed of our reform process, including re-orientation of strategies and planning processes towards meeting our goal of customer value. In this way, we consider that the AER can place weight on the efficiency of the forecasts for the 2024-29 period, providing a partial indication on the efficiency of our total capex.

The AER must also consider the most recent annual benchmarking report and the benchmark capital/operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period (capex factor 4). The purpose of this factor is for the AER to consider whether available benchmarking information can provide a partial indicator of the efficiency of the forecast expenditure, and if so the investigations and weight that should be ascribed to that data.

We note that the AER recently released their Annual Benchmarking Report (ABR) in November 2022. In addition to this, we have continued to rely on the AER's repex and augex models in determining an efficient level of capex. Based on this analysis we note:

- AER capex related measures: we are the 5th ranked DNSP for the Capex MPFP measure and our relative performance has been improving against the AER's capex related measures contained in the ABR. Our RAB/customer also continues to improve;
- Augex: Our forecast augmentation program is based on our detailed demand forecasts, capacity and utilisation information and development activity expectations and customer connection forecasts. We have previously applied the AER's augex model to test our forecast but consider this model has limitations in its applicability to greenfield growth-related

[4] On a net capex basis consistent with the CESS (i.e. gross capex less capital contributions and less disposals).

augmentation and is therefore more suitably used to identify general trends in asset utilisation and any potential outliers in the augex program. Nevertheless, our augex forecast; and

- Repex: Replacement capex is the largest category of capex. The primary test of this forecast is the AER's repex model which we consider is a benchmarking tool. The repex model predicts the likely asset replacement volumes and expenditure based on the number and age of assets in service, their assumed replacement age and historical unit costs. Using the AER's prevailing calibration approach, our forecast replacement capex for the 2024-29 period is lower than the forecast produced by the AER's repex model. Refer to Endeavour Energy - Brian Nuttall Consulting - 10.23 AER Repex Model - September 2022 - Public.

Overall, our analysis of benchmarking tools suggests that Endeavour Energy is trending in a positive direction and benchmarks favourably when key environmental factors are appropriately accounted for.

The final factor we have considered as a partial indicator of efficiency is the extent the capital expenditure forecast is preferable to arrangements with another person that do not reflect arm's length terms (capex factor 9). We confirm that our forecast capex for 2024-29 does not include any arrangement with any other person that do not reflect arm's length terms.

(d) an explanation of how the plans, policies, procedures and regulatory obligations or requirements identified in Workbook 1 – Forecast, regulatory templates 7.1 and 7.3 have been used to develop forecast capex; and

Refer to regulatory templates 7.1 and 7.3, sections 10.3 and 10.5 of our Regulatory Proposal and supporting attachments:

- Endeavour Energy - 10.01 Investment Management Framework (IMF) - November 2022 – Public;
- Endeavour Energy - 10.02 Asset Management Policy - May 2022 – Public;
- Endeavour Energy - 10.03 Network Business Strategy - November 2022 – Public;
- Endeavour Energy - 10.04 Investment Portfolio Decision Making - November 2022 – Public;
- Endeavour Energy - 10.05 Value Framework - November 2022 – Public;
- Endeavour Energy - 10.07 STPIS and non-compliant feeder CAPEX proposal - November 2022 – Public;
- Endeavour Energy - 10.22 Asset Risk Model Framework - November 2022 – Public;
- Endeavour Energy - 0.07 Expenditure Forecasting Methodology Statement - June 2022 – Public;
- Endeavour Energy - 10.42 Fleet Asset Strategy - November 2022 – Public;
- Endeavour Energy - 10.43 ICT Asset Strategy - November 2022 – Public; and
- Endeavour Energy - 10.46 Building, Property and other non-system asset strategy - November 2022 – Public.

(e) an explanation of how each response provided to paragraph 4.4.1(a)-(d) is reflected in any increase or decrease in expenditures or volumes, particularly between the current and forthcoming regulatory control periods, provided in Workbook 1 – Forecast, regulatory templates 2.1 to 2.11.

Increases and decreases in volumes and expenditures, particularly between the current and forthcoming regulatory control periods are discussed in our Regulatory Proposal and supporting documents, in particular the asset management plans detailed in our response to question 4.1 (d) above and sections 10.4 and 10.5 of our Regulatory Proposal and attachments supporting our capital expenditure forecast.

4.4.2 Identify which items of Endeavour Energy's forecast capex are:

(a) derived directly from competitive tender processes;

Forecast capex for those major projects that are in flight (i.e. commenced within the current RCP and scheduled for completion within the next RCP) have been derived directly from a competitive tender process. For the remainder, the historical unit rates used to develop our capex forecast do reflect our extensive use of external resources through our blended delivery model.

(b) based upon competitive tender processes for similar projects;

As noted above historical project costs are used to forecast future project expenditure, which typically have a proportion of costs that are subject to competitive tender process.

(c) based upon estimates obtained from contractors or manufacturers;

No part of the forecast capex is derived directly from estimates obtained from contractors or manufacturers.

(d) based upon independent benchmarks;

No part of the forecast capex is based on independent benchmarks.

(e) based upon actual historical costs for similar projects; and

As noted above historical project costs are used to forecast future project expenditure, which typically have a proportion of costs that are subject to competitive tender process.

(f) reflective of any amounts for risk, uncertainty or other unspecified contingency factors, and if so, how these amounts were calculated and deemed reasonable and prudent.

The key area of uncertainty in the capex forecast arises from projects proposed to provide capacity to service greenfield development. A number of projects have been proposed based on information from developers and the Department of Planning. The rationale for these is found in the various greenfield development business cases (Endeavour Energy - 10.20 AUGEX Selection of Cases for Investment ZIP - January 2023 – Public)

The expenditure proposed for each of these projects reflects the probability that is assigned to each individual development proceeding. Total expenditure proposed for these projects in total is expected to be sufficient to establish the infrastructure for those developments that do proceed.

4.4.3 Provide all documents which were *materially* relied upon and relate to the *deliverability* of *forecast capex* and explain the proposed *deliverability*.

Refer to Chapter 10 of our regulatory proposal for our assessment of the deliverability of our forecast capex.

Capex categories

4.4.4 Describe each *capex category* and expenditures relating to these categories identified in the *regulatory templates*, including:

(a) key drivers for expenditure;

The capex categories identified in the regulatory templates are, by definition:

- Augmentation Capital Expenditure;
- Connections Capital Expenditure;
- Distributed Energy Resource (DER) Hosting Expenditure; and
- Replacement Capital Expenditure.

See section 10.5 of our Regulatory Proposal for an explanation of the drivers for each category of expenditure for further details.

(b) an explanation of how expenditure is distinguished between:

(i) greenfield driven and reinforcement driven augex;

Classification of greenfield versus reinforcement driven Augex is made for each project or program on a case-by-case basis. The principles which guide the classification as greenfield are:

- the project is required to service large scale greenfield residential or industrial release areas;
- the existing infrastructure (if any) prior to development within these service areas are of a rural standard; and
- The development area is a significant distance from existing urban standard zone substations.

The principles which guide classification as reinforcement are:

- the project is required to service predominately infill development in existing urban areas (eg. increasing density); and
- the project is triggered by incremental load increase on existing assets within established service areas.

(ii) connections expenditure and augmentation capex;

In broad terms, connections expenditure is considered “customer initiated” whilst augmentation expenditure is associated with greenfield growth and industrial development driving the need to expand or reinforce the upstream network at higher voltages to accommodate organic load growth.

Endeavour Energy assigns a primary driver to each major project and program in its capital expenditure forecast. In regard to connections, expenditure is identified through the connection application process and is assigned to one of four specific connections-related programs.

This distinguishes between “connection” driven expenditure versus existing capacity constraints that have arisen over time in a gradual manner. Connections work can be further distinguished through the contestability framework which enables customers to seek a third-party to provide them with a connection service.

To the extent that it is economic to also perform any work on the low voltage distribution network at the time this service is being provided to the customer, Endeavour Energy will make a cost contribution. The amount payable by Endeavour Energy (typically to the ASP performing the work on behalf of the customer) is determined through the application of the Connections Policy and is limited to investment on assets that are or can be reasonably expected to be shared by multiple customers (i.e. the shared network). In this sense, connections capex is reactive in nature as opposed to augmentation capex which is proactively incurred to time the delivery of network infrastructure just in advance of when it is required.

(iii) replacement capex driven by condition and asset replacements driven by other drivers (e.g. the need for greenfield or reinforcement driven augex); and

Endeavour Energy adopts a range of approaches for identifying assets that are candidates for renewal, ranging from simple inspection and condition-based maintenance regimes through to detailed technical analysis of key asset indicators.

Using these approaches outlined above, short-term renewal programs are established based on available data supplemented with expert knowledge of the imminent end-of-life of the assets in question. These short-term programs are integrated into longer term renewal programs to provide accurate expenditure projections and enable the efficient integration of renewal, growth-driven and other asset management activities. Replacement capex is generally non-demand driven. However, a coordinated approach is taken whereby when a replacement need is identified, any augmentation

needs are taken into account, and if these augmentation needs are considered to be the dominant driver for the expenditure, then the project will become a capacity driven project.

We have also reviewed our overhead conductor replacement Case For Investment (CFI) and incremental resilience CFI (which includes a covered conductor replacement program) to ensure there has been no overlap between these programs.

(iv) any other capex category or opex category where Endeavour Energy considers that there is reasonable scope for ambiguity in categorisation.

Endeavour Energy has no categories where the categorisation is considered ambiguous. We acknowledge that there may be some investments which could have multiple impacts affecting more than one capex category. For instance, augmentation and connections work designed to increase the size or capacity of the network may have a consequential impact on DER integration and the network's export hosting capacity (DER capex). For multifaceted investments of this type, we have allocated costs to their appropriate capex category. Otherwise, we have attributed cost to the category corresponding to the primary or core objective of the investment as guided by the identified need.

Replacement capex modelling

4.4.5 In relation to information provided in Workbook 1 – Forecast, regulatory template 2.2 and with respect to the AER's repex model, provide:

(a) For individual asset categories in each asset group set out in the regulatory templates, provide in a separate document a description of the asset category, including:

(i) the assets included and any boundary issues (i.e. with other asset categories);

(ii) an explanation of how these matters have been accounted for in determining quantities in the age profile;

(iii) an explanation of the main drivers for replacement (e.g. condition); and

(iv) an explanation of whether the replacement unit cost provides for a complete replacement of the asset, or some other activity, including an extension of the asset's life (e.g. pole staking) and whether the costs of this extension or other activity are capitalised or not.

Endeavour Energy has developed a suite of documents to illustrate the processes used to align its replacement capex proposals / forecasts with the AER's guidelines. These documents outline the process that each asset is taken through, the assumptions and calculations to determine the risk / benefit to customers associated with an asset intervention and the results of the assessment.

These documents are divided into three categories, all providing different levels of detail associated with the repex forecasting methodology.

Case for Investment

These documents have been developed at an asset class level (e.g poles, crossarms, cables, conductors etc) and may contain multiple asset categories as per the regulatory templates. These documents provide a summary of the results of the economic evaluation that has been performed at the individual asset level as well as provide a forecast of replacement capex expenditure (driven by proactive risked based, conditional and functional asset failure). Refer to Endeavour Energy - 10.32 REPEX Selection of Cases for Investment ZIP - January 2023 – Public

Asset Class Plans

The asset class plans have been developed to provide a higher macro view to ensure individual decisions at the asset class level continue to hold true and align with expectations when looked at a

more macro level (e.g. the overheads switches asset class plan is a combination of the results of CFI's associated with DOF's, USL,s, ABS's, LBS's etc). These documents have also been established to create KPI's for different asset classes and allow the performance of the asset classes to me monitored. Refer to:

- Endeavour Energy - 10.26 Asset Class Plan HV Overhead Switchgear - October 2022 – Public;
- Endeavour Energy - 10.27 Asset Class Plan Overhead Conductors - November 2022 – Public;
- Endeavour Energy - 10.28 Asset Class Plan Overhead Structures - October 2022 – Public;
- Endeavour Energy - 10.29 Asset Class Plan Underground Cables - November 2022 – Public;
- Endeavour Energy - 10.30 Asset Class Plan Circuit Breakers - November 2022 – Public; and
- Endeavour Energy - 10.31 Asset Class Plan Power Transformers - November 2022 – Public.

System Strategies

System Strategy documents provide another layer of asset performance and combine all assets associated within the overhead network, underground network and substations into a single view. These documents provide visibility of where risk across the network resides, the types of risk and how it is proposed to change (increase or decrease) over the coming regulatory period. Refer to:

- Endeavour Energy - 10.24 Overhead System Strategy - November 2022 – Public; and
- Endeavour Energy - 10.25 Underground System Strategy - November 2022 – Public.

The major asset categories which drive our replacement capex forecast are described below:

Poles

- Poles are divided across each asset category based upon the assets material (e,g wood, concrete or steel) and to avoid edge cases / boundary issues the highest voltage on the structure is selected.
- Age profiles are extracted from the asset management system for each individual asset. Where age details did not exist historically (e.g. the asset was commissioned prior to any electronic asset management systems) processes and workflows were established to make the best possible estimate. These workflows were run once during the SAP implementation and the results are now stored as attributed against each asset.
- This asset category is entirely driven by conditional asset replacements based on ground line inspection data. The number of functional failures are relatively small (e.g. approximately 8 per year) and no proactive risk based replacement is proposed.
- Unit rates/asset intervention in this asset class is predominantly asset replacement with some asset reinforcing (e.g. pole nailing).
- Details of the cost / benefit calculations and asset strategy for this asset category can be found in the poles CFI, Structures Asset Class Plan and Overhead System Strategy.

Overhead Conductors

- Overhead conductors within the asset management system have two primary voltage classifications operating and constructed. Assets have been separated into asset categories based on operating voltage. This is primarily due to the 11kV overhead network being classified as constructed at 22kV (which the line is), however the connected assets (e.g. switches, transformers and surge arresters) are not and therefore the line can only be operated at it's operating voltage of 11kV.
- Age profiles are extracted from the asset management system for each individual asset. Where age details did not exist historically (e.g. the asset was commissioned prior to any electronic

asset management systems) processes and workflows were established to make the best possible estimate. These workflows were run once during the SAP implementation and the results are now stored as attributed against each asset.

- This asset category is driven by a mixture of risked based proactive intervention (for higher likelihood / consequence sections of line) as well reactive replacement (e.g. condition based and run to failure) for the remainder of the asset class.
- Unit rates / asset intervention in this asset class are asset replacements (capex) for risk-based intervention (e.g. where the asset is replaced). Conditional and functional failures are typically managed via repair of the existing conductor and would be classified as OPEX.
- Details of the cost / benefit calculations and asset strategy for this asset category can be found in the overhead conductors CFI, Overhead Conductors Asset Class Plan and Overhead System Strategy.

Underground Cables

- Overhead conductors within the asset management system have two primary voltage classifications operating and constructed. For underground assets it is unusual for the operating and construction voltages to be different and therefore the issue identified in overhead conductors does not exist. The operating voltage has been selected (for consistency) to distribute assets amongst the Asset Categories.
- Age profiles are extracted from the asset management system for each individual asset. Where age details did not exist historically (e.g. the asset was commissioned prior to any electronic asset management systems) processes and workflows were established to make the best possible estimate. These workflows were run once during the SAP implementation and the results are now stored as attributed against each asset.
- This asset category is primarily driven on a conditional / functional failure (reactive) basis (e.g. assets are repaired after an incident or identified via a maintenance activity / monitoring system). Whilst the majority of the asset base (by volume of assets) is managed reactively, a subset of transmission cables (oil filled cables) has been identified as being justified for a proactive risk-based program.
- Whilst the majority of this asset class is modelled REPEX, since no oil filled cables have historically been replaced the REPEX model is unable to forecast this expenditure. CAPEX associated with the replacement of the oil filled cables has therefore been included in unmodelled REPEX in reporting where it is being directly compared with the REPEX model outputs.
- Unit rates / asset intervention in this asset class are representative of a reactive asset replacement (capex) for conditional failures. The majority of reactive asset replacements are associate with known high likelihood of failure, low consequence cables (e.g. CONSAC), where a proactive program cannot currently be proposed. Where repair of the asset is not possible, to avoid ongoing repair costs (multiple failures of the same section of cable) replacement of the smallest section of cable is requested (e.g. between two columns). This allows the gradual replacement of the asset overtime.
- Details of the cost / benefit calculations and asset strategy for this asset category can be found in the underground cables CFI, Oil Filled Cables CFI, Underground Cables Asset Class Plan and Undergound System Strategy.

Service Lines

- Services Lines have been split across Asset Categories on the following basis “simple” equates to overhead service, whilst “complex” equates to an underground service. No other boundary issues exist in this asset category.
- Age profiles are extracted from the asset management system for each individual asset. Where age details did not exist historically (e.g. the asset was commissioned prior to any electronic asset management systems) processes and workflows were established to make the best possible estimate. These workflows were run once during the SAP implementation and the results are now stored as attributed against each asset.
- This asset category is proposed to be driven purely on a reactive nature. The reactive replacements will be a combination of conditional replacement (e.g. insulation degradation) and functional failure.
- Unit rates / asset intervention in this asset class are representative of a reactive asset replacement (capex) cost. NSW Service and Installation Rules do not permit the repair of a service (e.g. installation of a joint) and therefore most defects associated with service mains result in an asset replacement. Considering the time / cost difference between a repair and asset replacement, this is considered prudent.
- Details of the cost / benefit calculations and asset strategy for this asset category can be found in the Overhead and Underground services CFI.

Transformers

- The transformers Asset Category is a combination of multiple asset classes within Endeavour Energy’s asset hierarchy (predominantly distribution transformers (overhead and underground) and power transformers). The primary voltage / maximum rating of these assets has been selected to distribute the assets across the RIN Asset Categories.
- Due to limited asset replacements in the Power Transformers categories in the current RCP the REPEX model cannot currently generate a valid output for these asset categories. Power transformers has therefore been shown in the unmodelled category in some instances.
- Age profiles are extracted from the asset management system for each individual asset. Where age details did not exist historically (e.g. the asset was commissioned prior to any electronic asset management systems) processes and workflows were established to make the best possible estimate. These workflows were run once during the SAP implementation and the results are now stored as attributed against each asset.
- The distribution transformers (overhead and underground) asset categories are proposed to be driven purely on a reactive nature. The reactive replacements will be a combination of conditional replacement (e.g. as a result of an inspection) and functional failures. Power Transformers are a combination of both reactive risk based and planned proactive replacement.
- Unit rates / asset intervention in this asset class are representative of an asset replacement (capex) cost for each individual asset category.
- Details of the cost / benefit calculations and asset strategy for this asset category can be found in the Power Transformers CFI. The CFI for distribution transformers is still underdevelopment at the time of preparing this document, however all initial modelling has suggested a purely reactive program.

Switchgear

- The switchgear Asset Category is a combination of multiple asset classes within Endeavour Energy's asset hierarchy (predominantly distribution underground switchgear (overhead and underground) and circuit breakers). The primary has been selected to distribute the assets across the RIN Asset Categories. All distribution assets (padmount HV and LV switches, ABS, LBS etc) have been classified as "switches", whilst circuit breakers within substations have been classified as "circuit breakers".
- Age profiles are extracted from the asset management system for each individual asset. Where age details did not exist historically (e.g. the asset was commissioned prior to any electronic asset management systems) processes and workflows were established to make the best possible estimate. These workflows were run once during the SAP implementation and the results are now stored as attributed against each asset.
- All switchgear asset categories (switches and circuit breakers) are proposed to be driven by a combination of planned and reactive asset replacements. The reactive replacements will be a combination of conditional replacement (e.g. as a result of an inspection) and functional failures.
- Unit rates / asset intervention in this asset class are representative of an asset replacement (capex) cost for each individual asset category.
- Details of the cost / benefit calculations and asset strategy for this asset category can be found in the various overhead switch CFI's for ABS's, LBS, USL's, the distribution underground switch CFI as well as the circuit breaker CFI. These switches are then rolled up into the associated underground and overhead Asset Class Plans and associated Overhead or Underground System Strategies.

Public Lighting

- The Public Lighting Asset Category is a single asset class within Endeavour Energy's asset hierarchy, referred to as Public Lighting. Endeavour Energy includes Street Lighting control points within this same asset class, however this is excluded for the purposes of Public Lighting within the REPEX model.
- Age profiles are extracted from the asset management system for each individual asset. Where age details did not exist historically (e.g. the asset was commissioned prior to any electronic asset management systems) processes and workflows were established to make the best possible estimate. These workflows were run once during the SAP implementation and the results are now stored as attributed against each asset.
- Public Lighting lanterns have undergone several proactive replacement programs over the current RCP. These replacement programs have largely been driven by customers (e.g. local councils) to take advantage of reduced energy requirements associated with LED's. These proactive replacement programs are not expected to continue into the following RCP and all REPEX investment is expected to be reactive in nature (e.g. condition based replaced or function failure).
- Unit rates / asset intervention in this asset class represent replacement of the asset as generally there is very little if any repair options available.
- Details of the cost / benefit calculations and asset strategy for this asset category can be found in the Public Lighting CFI.

SCADA, Network Control & Protection

- The SCADA, Network Control & Protection asset category entails multiple asset classes within Endeavour Energy's asset hierarchy. The AER's definition of the asset category "field devices" includes both protection relays and SCADA RTU's.
- Age profiles are extracted from the asset management system for each individual asset. Where age details did not exist historically (e.g. the asset was commissioned prior to any electronic asset management systems) processes and workflows were established to make the best possible estimate. These workflows were run once during the SAP implementation and the results are now stored as attributed against each asset.
- All secondary system asset categories (protection and SCADA RTUs) are proposed to be managed by a combination of planned and reactive asset replacements, driven by risk (reliability, financial, bushfire, safety and technical obsolescence) based asset replacement strategy.
- Due to the nature of electronic devices which comprise large part of secondary system, there is no conditional failure or replacement. The reactive replacements will be purely driven by functional failures.
- Unit rates / asset intervention in this asset class are representative of an asset replacement (capex) cost.
- Details of the cost / benefit calculations and asset strategy for this asset category can be found in the CFI, Asset Class Plan of protection and SCADA RTU, as well as in the Secondary System Strategy.

Other

- Endeavour Energy has an objective to minimise the REPEX expenditure allocated to the "Other" categories. Historically large replacement projects (e.g. substation rebuilds) have been entirely included within the "other" category. The current asset level economic assessments will facilitate the primary asset replacements being allocated to the appropriate asset categories (e.g. Power Transformers, Circuit Breakers etc).
- A number of "other" categories will continue to be required including for Towers, miscellaneous substation equipment (e.g. AFIC units) and Substation Civils (e.g. builds, bunds, roofs etc). However these should be limited and reducing going forward.
- Primary drivers for intervention across these categories will defer for each asset class and are documented in the relevant / associated CFI.
- Unit rates will typically represent the reactive replacement cost associated with the individual asset class.

Connections expenditure

4.4.6 Provide and describe the methodology and assumptions used to prepare the forecasts of connection works including:

(a) Estimation of connection unit costs for each customer type; and

(b) Connection volumes for each customer type.

Unit cost and customer growth rate forecasts are based on:

- Average customer growth = 5-year average of growth rate across all customer types from previous regulatory period.

- Average connection cost = 5-year average of total construction connection cost from previous regulatory period.
- Unit cost = Average of Total construction connection cost / Average customer growth
- Applying our customer forecast model (using NIEIR forecasts as input data) to estimate customer growth for FY23 to FY29

Calculation of connection costs by customer type:

- Total connection costs for FY23 to FY29 are determined based on the unit cost and customer growth forecast outlined in previous step.
- Developed ratio of capex costs for different customer types based on 5-year moving average from previous years. Forecasted connection costs for FY23 to FY29 are split into different customer categories (Residential, Industrial & Commercial and Subdivision) as per these ratios. A similar approach is followed for distributing non-cash capital costs across customer categories.

Our customer forecast model (which applied NIEIR forecasts as input data) was used to determine the connection volume forecasts across Domestic, Industrial and Commercial customers. Domestic customers were further split into Residential and Subdivisions using 5-year moving average of ratios for these categories.

4.4.7 Endeavour Energy must provide its estimation of *customer contributions* based upon the estimated life and revenue to be recovered from *connection assets*, including:

(a) the expected life of the connection;

Our customer contributions forecast assumes a recovery period of 49 years based on economic life of the assets including LV cables, HV cables and substations.

(b) the average consumption expected by the customer over the life of the connection; and

Based on our forecast customer number growth and forecast energy consumption growth the average annual consumption for new customers over the regulatory period FY25 to FY29 is shown below.

Customer Type	Average Annual Energy Consumption/Customer (MWh)
Residential	5.56
Commercial	17.99
Industrial	948

(c) any other factors that influence the expected recovery of the Endeavour Energy network use of system charge to customers.

No other factors have been identified.

Non-network alternatives

4.4.8 Identify the policies and strategies and procedures in the response to Workbook 1 – Forecast, regulatory template 7.1 which relate to the selection of efficient non-network solutions.

Consideration of non-network alternatives is embedded in our investment decision making. This is reflected in the following documents listed in regulatory template 7.1:

- Investment Management Framework (IMF);
- Asset Management Policy;
- Network Business Strategy;
- Value Framework;
- Growth Servicing Strategy; and
- Asset Risk Model Framework.

Additionally, our Demand Side Engagement Document (Attachment 10.06) details our approach and processes for identifying and evaluating non-network options and Stand-Alone Power System (SAPS) for addressing network limitations.

4.4.9 Explain the extent to which the provision for efficient non-network alternatives has been considered in the development of the forecast capex and forecast opex proposals.

Forecast Capex

Our investment decision making framework considers the potential for non-network alternatives and new technology solutions as credible solutions to address network constraints. This approach is consistent with the RIT-D guidelines and NER requirements. In most instances, this consideration also applies where the RIT-D criteria has not been met.

Where a non-network (including a SAPS option) is technically feasible, we publish an options screening report and inform our request for proposals for non-network alternatives to persons registered on our industry engagement register. Evidence of how we apply the requirements of the RIT-D to Network Investment Projects are provided in supporting attachments.

- Endeavour Energy - 10.20 AUGEX Selection of Cases for Investment ZIP - January 2023 – Public; and
- Endeavour Energy - 10.32 REPEX Selection of Cases for Investment ZIP - January 2023 – Public.

The forecast capex proposal is initially developed using the network need date and the RIT-D process determines the preferred option and the appropriate timing according to probabilistic analysis. However, our ability to identify prospective feasible non-network alternatives early in the process has improved via the implementation of our New Technology Master Plan (NTMP) tool. This tool allows us to assess network support options of emerging technologies and services including Virtual Power Plants (VPP), grid-scale battery energy storage solution (BESS), community batteries, commercial direct load control and residential behavioural demand response.

Based on our initial assessment using the NTMP tool, we have identified that non-network alternatives are highly likely to defer the following projects:

Project	Potential Non-Network Solution
South Penrith Zone substation	Grid-scale BESS
North Bomaderry Zone substation establishment	VPP, community batteries
Culburra Beach Zone substation	Grid-scale BESS, residential VPP or Demand response
Catherine Park - Stage 2	Grid scale BESS, Residential VPP or demand response, community batteries
Calderwood Zone substation - Stage 2	Grid scale BESS, Residential VPP or demand response, community batteries

We estimate the likely deferral value of these projects (noting the deferral achieved will vary per project) to be approximately $7 million and our 2024-29 capex program has been adjusted to reflect these deferrals. However the feasibility and cost of non-network alternatives can only be confirmed once a market tender process the RIT-D process is concluded.

Forecast Opex

We have included $3.4 million as a step change in our opex proposal to account for the cost of deploying the non-network alternatives required to defer augmentation projects. The proposed amount is efficient as it is less than the benefits of the network investment deferrals which have been reflected in our capex proposal.

We have proposed this step change on the basis:

- These costs, although not yet committed to discrete programs, are a conservative estimate of the uplift in our non-network opex and not included in our base year opex;
- The rate of change component of our opex forecast does not provide for these costs;
- These costs are incremental to non-network costs in our base year opex which have been incurred for projects that will continue into the 2024-29 regulatory period; and
- Through our NTMP tool which better equips us to consider a growing range of non-network alternatives, we anticipate that our 2024-29 demand management opex forecast will become part of our recurrent opex in future regulatory periods.

Given the capabilities of the NTMP tool, the continued emergence of new technology and innovative services, and our adoption of contemporaneous screening of non-network alternatives, we expect to identify more projects which could be deferred through non-network solutions.

Therefore, the cost of implementing non-network alternatives in 2024-29 will likely exceed our proposed $3.4M. Our modest step change proposal is consistent with our approach of constraining our opex step changes and in recognition of forecasting uncertainty.

4.4.10 Identify each non-network alternative that Endeavour Energy has:

(a) commenced during the current regulatory control period; and

(b) selected to commence during, or will continue into, the forthcoming regulatory control period.

The non-network alternatives (including trials) we have commenced in the 2019-24 period are listed below. Those which will continue into the 2024-29 period are noted in the status column.

Non-Network Alternative Commenced In 2019-24	Status
Off Peak Plus	Continuing into 2024-29
Business Park Demand Management Program (Oakdale business park)	Continuing into 2024-29
Microgrid Project Definitions and Blueprints for Western Sydney developments	Continuing into 2024-29
Stand Alone Power Supply at Kandos (Trial)	Completed during 2019-24
PowerSavers	Continuing into 2024-29
Dynamic Operating Envelopes	Continuing into 2024-29
E-Bus Depot Energy Management	Completed during 2019-24
Bawley Point & Kioloa Community Microgrid	Continuing into 2024-29

As discussed in 4.4.9 and 4.4.12(a), whilst we have not finalised non-network alternatives commencing in 2024-29, we have made adjustments (deferrals) to our SCS capex forecast in anticipation of identifying and deploying efficient non-network alternatives during the period.

4.4.11 For each *non-network* alternative identified provide a description, including cost and location.

Non-Network Project	Description	Cost	Location
Off Peak Plus	In May 2021 we launched our Off Peak Plus program installing smart meters at 2,500 homes across Albion Park in partnership with ten energy retailers and two metering companies. This avoided replacing and upsizing off-peak control systems at a nearby zone substation. The smart meters represented a lower cost option that would provide additional benefits through energy and power quality data. This supports lower bills for customers along with improved reliability and export hosting. The smart meters enable the dynamic control of hot water systems to switch on during the day when surplus power is being generated from household solar systems.	$0.5M	Pilot project at Albion Park and expansion to other areas in 2024-29
Business Park Demand Management Program	Complimentary and expert energy audits of major customer sites to identify peak demand reductions and the offering of incentives for demand reduction initiatives. This DM program works well in a business park setting where the zoning and land use is exclusively for enterprise and there is close proximity between the customers to allow for efficient time management of energy audits	$0.1M	South Erskine Park enterprise zoned employment lands with expansion to Western Sydney in 2024-29.
Microgrid Blueprints and Project definitions for Western Sydney	Development of Project Definitions and implementation blueprints with two major clients, in a co-creation process, in Western Sydney for sustainability driven microgrids to maximise the use of renewable energy in the major client's proposed developments.	$0.3M	Two Western Sydney development areas.

Non-Network Project	Description	Cost	Location
Stand Alone Power System (Trial)	A trial starting with implementation of a stand-alone power supply to holiday accommodation in a remote part of a national park and avoiding the replacement of end of life steel mains reducing risk of bushfire and improving supply reliability and security.	$0.2M	Kandos
PowerSavers	The PowerSavers program for residential customers has been established to manage a range of smart load devices including air-conditioning units, water heaters, EV chargers and assets comprising solar and battery unit combinations. Customers receive notifications of demand response events on forecast peak demand days and participate in incentives depending on their individual demand management achievements. Featuring a web portal, and custom-branded iPhone and Android mobile application and trialled this as an innovative approach using a single platform to improve customer engagement, recruitment and management of our portfolio of residential demand management (DM) programs. They included behavioural demand response, air conditioner control, battery energy storage and energy saving education programs.	$0.5M	Various locations across Western Sydney with the largest uptake in the Penrith LGA
Dynamic Operating Envelopes	The Evolve project which commenced in February 2019, is a collaboration between industry, academia and government to develop software applications to integrate with distribution network operational technologies (and systems used by aggregators) to manage Distributed Energy Resources (DER) under their control. The project comprises multiple trials and demonstrations to eventually calculate and publish operating envelopes for all DER connected to the distribution network. Endeavour Energy implemented and tested the Evolve operating envelope platform in July 2021. Endeavour Energy intends to set real-time operating envelopes for its customer DERs by deploying the software applications and associated services developed as part of the Evolve project. The aim of the Evolve program is to efficiently manage residential customer smart load devices and generation devices by applying operating envelopes to protect the security of the distribution network.	$0.1M	Various locations in Western Sydney
E-Bus Depot Energy Management	Endeavour Energy is collaborating with partners on an innovative trial to integrate electric bus charging with demand signals on the energy grid. As more electric vehicles join the road, demand for electricity increases, putting added pressure on the grid. Without smart charging, there is an increased risk of peak demand increasing, requiring costly upgrades to network infrastructure. The joint trial in Penrith aims to avoid this issue and alleviate the added pressure on the grid by	$0.1M	Western Sydney and Penrith LGA

Non-Network Project	Description	Cost	Location
	feeding real-time demand data into control algorithms that help determine the optimal time to charge. Endeavour Energy has committed to installing 17 distribution transformer monitors on relevant distribution transformers to gain full real-time visibility on the upstream low voltage and high voltage network the bus depot is connected to. By collaborating with our partners, this live data can be used to inform and optimise the control systems that are used to charge the buses. When demand is low or there is a surplus of solar power on the network, buses can charge without adding to peak demand, better utilising the existing grid.		
Bawley Point & Kioloa Community Microgrid	The Bawley Point, Kioloa and Termeil communities are located at the extreme southern end of Endeavour Energy's franchise area. The area is a popular tourist destination, and this means that energy demand can increase four to five-fold during peak holiday periods. Being at the very end of the Endeavour Energy network, electricity services at Bawley Point and Kioloa experience relatively high SAIDI and SAIFI values. Load has also increased to near capacity with regional permanent population movements, in part due to COVID-19. Additionally, the network is voltage constrained – facing low voltage during peak periods, and high voltage during the low demand periods, which will in the longer-term result in poor power quality and curtailment of customers' DER. The major features of the project involve: • Community co-design, and integration of community owned assets; • Turnkey supply and installation of a new ~3MVA/3MWh Battery Energy Storage System (BESS); • Roll out of residential batteries and solar (funded through the NSW Government's Bushfire Livelihoods Economic Recovery program); • A Distributed Energy Resources Management System (DERMS) to enable control of local generation and storage; and • Demand management programs (smart streetlights, smart metering and Off-Peak Plus), and the integration of larger customer assets to assist in supporting the network.	>$1M (including Govt. grant)	Shoalhaven LGA

4.4.12 Provide, for each year of the current regulatory control period, and for the forthcoming regulatory control period, details of each payment made, or expected to be made, by Endeavour Energy to an embedded generator in reflection of any costs avoided by deferring augmentation of:

(a) Endeavour Energy's distribution network; or

Endeavour Energy has not made any payments to embedded generators for deferring augmentations in the current regulatory period. We have no current contractual arrangements that obligate us to make such payments in the remainder of the 2019-24 regulatory control period or for the 2024-29 regulatory control period.

A potential for a grid-scale BESS at Penrith which would defer network augmentation is in a commercial evaluation phase as of January 2023. If successful, once an agreement is reached, we may commit to making payments to an embedded generator. Reaching an agreement is contingent on negotiating costs and technical considerations relating to the connection voltage level of the Grid BESS between Endeavour Energy and the prospective BESS proponent.

(b) the relevant transmission network.

Not applicable

4.5 Forecast input price changes

4.5.1 Provide:

(a) information supporting or relied upon that explain the change in the price of goods and services purchased by *Endeavour Energy*, including evidence that any materials price forecasting method explains the price of materials previously purchased by *Endeavour Energy*.

Endeavour Energy has provided in Endeavour Energy - RIN0.01 Reset RIN Workbook 1 - Forecast - January 2023 – Confidential, the CPI series data and index used to derive our proposed opex and capex forecasts.

For inflation, we have applied the AER's approach for the regulatory treatment of inflation using the RBA's forecast of inflation from their November 2022 Statement of Monetary Policy. We have also inputted CPI values consistent with pre-lodgement advice received from the AER.

4.5.2 Provide also an explanation of :

(a) the methodology underlying the calculation of each price change, including:

(i) sources;

(ii) data conversions;

(iii) the operation of any model(s) provided under paragraph 4.2.5(b); and

(iv) the use of any assumptions such as lags or productivity gains.

Section 11.7 of our Regulatory Proposal provides a general overview of the forecast real price changes in the 2024-29 regulatory control period for opex.

We note we have not applied any real cost escalation for materials to either our capex or opex forecasts and have applied real cost escalation for labour, as forecast by independent macroeconomic experts BIS, only for labour. This approach is consistent with the requirements of the Reset RIN and the forecasts are provided in Endeavour Energy - BIS - 0.10 Real Cost Escalation Forecast - November 2022 - Public

To derive our labour price growth forecast, we have applied the AER's benchmark proportion of labour (59.2%) to the NSW EGWWS real WPI forecast provided by BIS. We have also applied a 0.5% productivity improvement factor to our opex forecast.

(b) whether the same price changes have been used in developing both the forecast capex proposal and forecast opex proposal; and

Only real price changes in labour have been applied to derive our opex forecast. As part of our commitment to achieving capital productivities (noting an unscoped productivity gains already applies to opex) we did not apply any real cost escalation to our capex forecast. If we were to apply real escalators to our forecast capex the same escalators would be applied.

(c) if the same price changes have not been used in developing both the forecast capex proposal and forecast opex proposal, why it is appropriate for different expenditure escalators to apply.

Not applicable.

4.6 Operating and maintenance expenditure

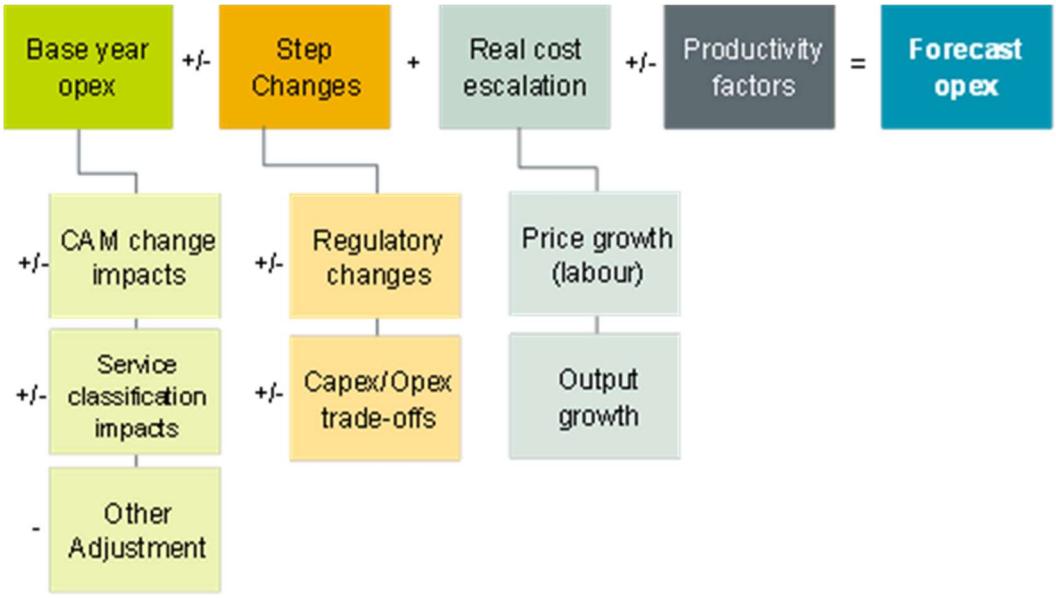
Total forecast operating and maintenance expenditure (opex)

4.6.1 Provide:

(a) justification for Endeavour Energy's total forecast opex, including:

(i) why the proposed total forecast *opex* is required for *Endeavour Energy* to achieve each of the objectives in clause 6.5.6(a) of the *NER*;

Endeavour Energy has used the base-step-trend methodology for estimating our forecast opex requirements. In applying this approach we have used the AER's top-down Opex Model which can be described as follows:



To summarise, we have used 2022-23 (the fourth year of the current regulatory period) as the base year from which our 2024-29 opex forecast has been derived. We consider the opex in this year (adjusted for DMIA costs, movements in provisions and accounting standard changes) to be efficient and exclusive of non-recurring expenditure. Additionally, to provide further assurance that our base year is efficient we note it is below the opex allowance from the AER's 2019-24 Determination.

Non-routine costs (i.e. debt raising costs) have been calculated by applying a benchmark debt raising unit rate to the debt portion of our regulated asset values.

Further information on our opex forecasts is provided in Chapter 11 of our Regulatory Proposal. The AER's Opex model which gives effect to the methodology is included at Endeavour Energy - 11.01 Opex Model - January 2023 – Public.

(ii) how *Endeavour Energy's* total forecast *opex* reasonably reflects each of the criteria in clause 6.5.6(c) of the *NER*; and

In order to achieve each of the operating expenditure objectives, we must have the required capabilities, personnel and systems to achieve them. For example, one of the operating expenditure objectives is to maintain the safety of the distribution system through the supply of standard control services. In undertaking this activity and in operating the necessary systems, Endeavour Energy must incur maintenance operating expenditure.

Our total forecast operating expenditure therefore comprises the costs of undertaking all the related activities and to operate the necessary systems to deliver each of the operating expenditure objectives listed in clause 6.5.6(a) of the NER. Our total forecast operating expenditure comprises two cost groups. The table below shows the operating expenditure objective/s for each cost group.

Operating expenditure cost group	Activities	Operating expenditure objectives achieved
System maintenance operating expenditure	Maintenance operating expenditure is required to undertake various activities on Endeavour Energy's electrical network. These activities, and associated cost, are critical to achieve all four operating expenditure objectives.	All operating expenditure objectives
Operation, support and other expenditure	Operation expenditure are costs incurred in undertaking the required activities to directly support the operation of Endeavour Energy's electrical network. Support expenditure is necessary for the normal operation of Endeavour Energy as a business such as management costs, financial reporting or human resources management costs. These costs would be found in any typical business. They are essential to the effective running and operation of the network and therefore required to achieve all of the operating expenditure objectives.	All operating expenditure objectives

Further description of the activities within each opex cost groups are provided below.

1. System maintenance activities and costs

Inspections – Routine asset inspection and condition monitoring activities include field and aerial inspection of overhead distribution assets (poles, pole top structures, conductors, substation structures, transformers, high and low voltage switchgear, and other distribution electrical equipment); powerline to ground and vegetation clearances; thermography of powerline and substation structures; and non-destructive testing of power transformers and switchgear;

Maintenance and repair – This category covers all maintenance and repair activities on network assets but excludes fault and emergency repairs and restoration of supply for planned and unplanned interruptions which are categorised as emergency response. Components include maintenance and repair of distribution powerline equipment, damaged or inoperable switchgear, distribution and zone substations, and customer service mains;

Vegetation management – This work, mainly carried out by external contractors, reduces safety hazards and interruptions to supply on our overhead electricity network. Compliance with this policy is a critical control measure associated with management of bushfire and community safety risk. Vegetation management must be done regularly to ensure a reliable and safe electricity supply. It must also be done in a way that is sensitive to environmental and community issues;

Emergency response – This covers fault and emergency repairs and restoration of supply for planned and unplanned interruptions caused by events such as storms, equipment failures, acts of vandalism, and vehicle collisions. When notified of an interruption to customer supply, Endeavour Energy promptly dispatches field employees to deal with the fault; and

Network maintenance operating cost – This cost category covers other activities that are required to support the maintenance of the network itself such as: fire mitigation (excluding vegetation management); field training; and any other cost required for the safe operation and maintenance of the distribution network.

2. Operations and support activities and costs

Network operations – This category of costs cover operating costs required to manage the network such as: staffing of the control centre; operational switching personnel; outage planning personnel; and provision of authorised distribution personnel. It also covers support activities directly related to the network such as: demand forecasting; procurement, logistics and stores; information technology (IT) costs directly attributable to distribution operation; and land taxes.

Information, communication and technology – costs relating to the operation and maintenance of various IT technologies and telecommunication system required for the effective operation of Endeavour Energy's infrastructure and day to day operations.

Customer service – This activity includes call centre and operational activities relating to customer interaction and reporting on issues such as: distribution faults and safety hazards; complaints about the quality and reliability of supply; queries on new connections, disconnections and reconnections; and queries on improving power factor or load factor.

Training and development – costs relating to centralised coordination and delivery of the technical, regulatory and professional development needs for Endeavour Energy's employees and compulsory training related to network access for contractors who work on the network.

Finance costs - costs relating to:

- corporate accounting and reporting;
- budgeting, forecasting, commercial services, investment analysis and business support;
- treasury, taxation and cash management; and
- regulatory reporting and fixed asset management and reporting.

Other operations and business support costs - these relate to:

- fleet and logistics management;
- insurance;
- human resources management;
- workers compensation, occupational health, well-being and safety;
- regulation and implementation of non-network programs; and
- management including the Board of Directors, Chief Executive Officer and Chief Operating Officer.

In addition to the forecast opex that Endeavour Energy proposed, the AER also allows a debt raising cost. The AER has accepted this cost as a legitimate operating expenditure that is required to meet the opex objectives.

(iii) how *Endeavour Energy's* total forecast *opex* accounts for the factors in clause 6.5.6(e) of the *NER*.

In accordance with 6.10.1(b) and 6.11.1(b) of the NER, the AER must have regard to the operating expenditure factors as well as the information included in or accompanying Endeavour Energy's Regulatory Proposal, written submissions and any analysis undertaken by or for the AER.

We provide the table below to demonstrate how our forecast opex satisfactorily addresses each of the factors in clause 6.5.6(e) of the NER and supports the AER's assessment.

Forecasting method related expenditure factors	Addressed
(4) the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period;	The AER's 2022 annual benchmarking report stated that Endeavour Energy has shown strong increases in productivity since 2016 and remains close to the most productive distributors in 2021. This is despite the AER's opex efficiency models do not explicitly consider the impact of operating environmental factors which previous analysis has shown that, for several factors, Endeavour Energy operates at a relative cost disadvantage. Our FY23 base year opex is not forecast to be materially different from our FY21 opex and therefore can also reasonably be considered efficient. Our opex performance in recent years has been impacted by our ICT & Digitial transformation program, meeting strong growth in greenfield areas, the impacts of COVID-19 and global economic downturn. Despite this, our opex has generally continued to reduce from historic levels. As a result we have significantly improved our benchmarking performance in recent years. Our Opex MPFP has improved from 10th in 2016 to 4th in 2021. We also consider our category level performance has been improving. This can be evidenced through the changes in partial performance indicators (PPI) for key opex categories over recent years as published as part of the annual benchmarking report. Also, alternate measures, specifications and analysis provides further support of our efficiency. As a result, our FY23 base year opex is lower than the AER's substitute forecast (by our calculations).
(5) the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;	We have included information relating to our actual and expected performance over the 2019-24 period in section 11.4 of our proposal. We detail our efficiency programs implemented over the course of the period, the cost pressures we have managed and other key events. We forecast that we will spend below the AER's opex allowance for the 2019-24 period.
(5A) the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers;	Our expenditure forecast process has considered the concerns of electricity consumers as identified in the course of our engagement with electricity consumers (opex factor 5A). We engaged customers on a range of issues and specifically with our Regulatory Reference Group (RRG) on our proposed step changes. The findings from our customer and stakeholder engagement support the basis of our proposed total opex including in relation to price affordability, and maintaining current levels of safety and reliability. See section 11.2 and Chapter 5 of our Regulatory Proposal.
(6) the relative prices of operating and capital inputs;	We have considered the relative prices of operating and capital inputs (opex factor 6). As noted above we have sought to assess all feasible options when addressing a need including opex and capex

Forecasting method related expenditure factors	Addressed
	options. When doing so, we have used best practice methods for deriving the relative cost of opex and capex solutions.
(7) the substitution possibilities between operating and capital expenditure;	We have considered the substitution possibilities between operating and capital expenditure in developing our forecast opex. A key step in our expenditure forecast process is to consider the full range of alternative options, including areas where there may be opex solutions such as maintenance, which have then been factored into our opex forecasts. The two most significant interactions between capex and opex relate to replacement capex and maintenance opex and non-network solutions. Our opex forecast is based on existing maintenance practices, specifically the 2022-23 base year which is reflective of a sustainable level of replacement capex. Any amendments to our replacement program are likely to have an impact on our required maintenance opex (although the relationship is difficult to quantify). In regards to non-network solutions we will incur additional opex during the period where it is efficient to do so to defer capex and in consideration of the relevant incentive schemes. We have proposed a step change amount to support capital investment deferrals already factored into our capex forecast.
(8) whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4;	Endeavour Energy was subject to the efficiency benefit sharing scheme (EBSS) for the current 2019-24 period. The EBSS provides incentives for business to pursue efficiency improvements in opex and to share efficiency gains with customers. This is demonstrated by the improvement in our opex forecast over the course of the 2019-24 period. This performance was achieved by the implementation of a number of cost saving initiatives. It has set a solid platform for Endeavour Energy in ensuring that the forecast opex for the 2024-29 period is efficient. In accordance with the revealed cost, EBSS incentive framework we have forecast our opex requirements using a base-step-trend methodology.
(9) the extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms;	We have considered as a partial indicator of efficiency is the extent the operating expenditure forecast is referable to arrangements with another person that do not reflect arm's length terms (opex factor 9). We confirm that our forecast opex for 2024-29 does not include any arrangement with any other person that do not reflect arm's length terms.

Forecasting method related expenditure factors	Addressed
(9A) whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);	Endeavour Energy's forecast method considered whether any opex should be identified as contingent projects, and therefore excluded from the total forecast capex or opex for standard control services (opex factor 9). We found that no component of our opex cost categories met the criteria of a contingent projects set out in 6.6A.1 of the Rules.
(10) the extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives; and	Endeavour Energy has considered and made provision for efficient and prudent non-network alternatives (opex factor 10). We have investigated ways to defer augmentation at specific sites of our network when developing our forecasts, and have incorporated the expected reduction in system demand from the implementation of new broad based demand management activities.
(11) any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s);	Not applicable to opex.
(12) any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised Regulatory Proposal under clause 6.10.3, is an operating expenditure factor.	Will only be relevant to our revised proposal, if the AER raises an additional factor in making their draft decision.

4.6.2 If Endeavour Energy used a revealed cost base year approach to develop its total forecast opex proposal, provide:

(a) explanation and justification for why that base year represents efficient and recurrent costs.

Refer to section 11.5 of our Regulatory Proposal.

4.6.3 If Endeavour Energy does not use a revealed cost base year approach to develop its total forecast provide:

(a) explanation of major drivers for the increases and decreases in expenditure by *opex category* in the *forthcoming regulatory control period* compared to actual historical expenditure;

(b) explanation and justification for:

(i) whether *Endeavour Energy* considers there is a year of historical *opex* that represents efficient and recurrent costs; or

(ii) why *Endeavour Energy* considers no year of historical *opex* represents efficient and recurrent costs.

Not applicable.

Output growth

4.6.4 Provide:

(a) the output growth drivers Endeavour Energy used to develop the amount of total forecast opex attributable to output growth;

Output growth relates to changes in the volume of services that we are required to provide resulting from network expansion or contraction. We expect our network will grow in the 2024-29 regulatory period (as reflected by a positive output growth value) mainly due to significant forecast increases in new connections and associated network extensions arising from planned greenfield developments.

The additional operating costs required to meet our obligations to maintain and operate a growing network is considered through our forecast output growth figures. To account for output growth the AER has developed three industry standard weighted output variables that align to economic benchmarking variables used by the AER. These variables are as follows:

- customer numbers;
- circuit length; and
- ratcheted maximum demand.

We have adopted these variables and their weightings (per each model specification) in calculating our output growth forecast for 2024-29. This is demonstrated in our opex model Endeavour Energy - 11.01 Opex Model - January 2023 – Public.

(b) the weight applied to each output growth driver;

Refer to Endeavour Energy - 11.01 Opex Model - January 2023 – Public.

(c) the forecast amount for each output growth driver;

Refer to Endeavour Energy - 11.01 Opex Model - January 2023 – Public.

(d) evidence that the growth drivers explain cost changes due to output growth; and

We have adopted the methodology consistently applied by the AER in their opex decisions to account for output growth for distribution networks.

This approach was based on advice provided to the AER from Economic Insights (EI) and to our knowledge remains the accepted approach as per the advice from the AER's new consultant Quantonomics. The output factors chosen by EI (customer numbers, circuit length and ratcheted maximum demand) were based on three selection criteria, namely:

- they align with the NEL and NER objectives;
- they reflect the services provided to customers; and
- they are significant outputs which impact costs.

We consider these three drivers are the main contributors to costs related to output growth.

The weights of each are based on Economic Insights' opex cost function analysis. Notwithstanding issues around monotonicity violations of the Translog models and how to reflect exports in the AER benchmarking models – both of which are currently subject to AER consultation, we do not have any robust evidence at this stage to suggests additional factors or alternative weightings should apply or

the current approach materially undercompensates or overcompensates for the impact of output growth on opex.

(e) an explanation of how, in developing the amount of total forecast opex attributable to output growth Endeavour Energy applied the above output growth measures.

Values for each of the three factors used to determine to overall change in opex attributable to output growth were estimated in accordance with our internal forecasting processes. These estimates are based on robust and proven forecasting procedures, made by subject matter experts using the most up-to-date information and data. For more information on our output growth forecasts, refer to Chapter 7 of our Regulatory Proposal.

Output growth drivers were applied through the AER's Opex model (Endeavour Energy - 11.01 Opex Model - January 2023 - Public). Weights for each driver were attributed in accordance with those consistently applied by the AER and outlined above.

Real price changes

4.6.5 Provide:

(a) the labour and non-labour inputs used to develop the amount of total forecast *opex* attributable to input price growth;

(b) the weight applied to each labour and non-labour input;

(c) the forecast growth rate applied to each labour and non-labour input; and

(d) an explanation of how, in developing the amount of total forecast *opex* attributable to changes in the price of labour and non-labour inputs, *Endeavour Energy* applied the real price measures in *Workbook 1 – Forecast, regulatory template* 2.14.

Endeavour Energy engaged BIS Oxford Economics (BIS) to estimate labour and non-labour price escalation values in for the 2024-29 period. It was determined that the price of labour is expected to exceed CPI forecasts and as such, we have proposed a real price of labour increase. We have not proposed a real price increase for materials consistent with standard AER practice not to accept any such proposal.

Chapter 11 of our Regulatory Proposal details our forecast real price change. In brief, our real price estimates are based on forecast wage price index (WPI) of labour in the utilities sector (EGWWS) in NSW. Labour price forecasts were provided by BIS and their report is included as attachment Endeavour Energy - BIS - 0.10 Real Cost Escalation Forecast - November 2022 - Public. Real labour price escalators are also provided in Endeavour Energy - RIN0.01 Reset RIN Workbook 1 – Forecast - January 2023 – Confidential.

To derive our overall real price change forecast, we have adopted the weightings most recently applied by the AER. The labour/non-labour cost split for opex to being 59.2% (labour) and 40.8% (non-labour).

Real price changes were applied through the AER's Opex model (Endeavour Energy - 11.01 Opex Model - January 2023 - Public).

Productivity change

4.6.6 Provide, in percentage year on year terms, the productivity measure that *Endeavour Energy* used to develop the amount of total forecast *opex* attributable to changes in productivity.

We have applied a 0.5% annual productivity factor consistent with the AER's 2019 final decision paper on Forecasting productivity growth for electricity distributors. Refer to Endeavour Energy - 11.01 Opex Model - January 2023 - Public.

4.6.7 Provide an explanation of:

(a) how, in developing the amount of total forecast *opex* attributable to changes in productivity, *Endeavour Energy* applied the productivity measure;

(b) whether *Endeavour Energy's* forecast productivity changes capture the historical trend of cost increases due to changes in *regulatory obligations or requirements* and industry best practice.

The productivity factor has been applied through the AER's Opex model (Endeavour Energy - 11.01 Opex Model - January 2023 - Public). The AER's final decision paper on Forecasting productivity growth for electricity distributors discusses the extent to which this forecast captures the historical trend of cost increases due to changes in regulatory obligations or requirements.

Step changes

4.6.8 Provide an explanation of why Endeavour Energy considers:

(a) the efficient costs of the *step change* are not provided by other components of *Endeavour Energy's* total forecast *opex* such as base *opex*, output growth, real price growth or productivity growth;

(b) the total forecast *opex* will not allow *Endeavour Energy* to achieve the objectives in clause 6.5.6(a) of the *NER* unless the *step change* is included; and

(c) the total forecast *opex* will not reasonably reflect the criteria in clause 6.5.6(c) of the *NER* unless the *step change* is included.

Refer to section 11.6 of our regulatory proposal.

For details relating to our proposed Insurance Premium step change, refer to Endeavour Energy - 11.03 Insurance Premium Opex Step Change - December 2022 – Confidential.

For details relating to our holistic approach to DER investment which includes our proposed Network Visibility and Solar Soak/Off-peak Conversion step changes, refer to Endeavour Energy - 10.40 DER Integration Strategy and Business Case - December 2022 – Public.

4.6.9 For each *step* change in forecast expenditure, provide a description of the *step change* and an explanation of:

(a) when the change occurred, or is expected to occur;

(b) what the driver of the *step change* is;

(c) how the driver has changed or will change (for example, revised legislation may lead to a change in a *regulatory obligation or requirement*); and

(d) whether the *step change* is recurrent in nature.

Refer to section 11.6 of our regulatory proposal.

For details relating to our proposed Insurance Premium step change, refer to Endeavour Energy - 11.03 Insurance Premium Opex Step Change - December 2022 – Confidential.

For details relating to our holistic approach to DER investment which includes our proposed Network Visibility and Solar Soak/Off-peak Conversion step changes, refer to Endeavour Energy - 10.40 DER Integration Strategy and Business Case - December 2022 – Public.

4.6.10 For each *step change* in forecast expenditure, provide justification for when, and how, the *step change* affected, or is expected to affect:

(a) the relevant *opex category*;

(b) the relevant *capex category*;

(c) total *opex*; and

(d) total *capex*.

Refer to section 11.6 of our regulatory proposal.

For details relating to our proposed Insurance Premium step change, refer to Endeavour Energy - 11.03 Insurance Premium Opex Step Change - December 2022 – Confidential.

For details relating to our holistic approach to DER investment which includes our proposed Network Visibility and Solar Soak/Off-peak Conversion step changes, refer to Endeavour Energy - 10.40 DER Integration Strategy and Business Case - December 2022 – Public.

4.6.11 For each *step change* in forecast expenditure, provide the process undertaken by *Endeavour Energy* to identify and quantify the *step change*; provide cost benefit analysis that demonstrates how *Endeavour Energy* proposes to address the *step change* in a prudent and efficient manner, including:

(a) the timing of the *step change*; and

(b) if *Endeavour Energy* considered a 'do nothing' option, evidence of how *Endeavour Energy* assessed the risks of this option compared with other options.

Refer to section 11.6 of our regulatory proposal.

For details relating to our proposed Insurance Premium step change, refer to Endeavour Energy - 11.03 Insurance Premium Opex Step Change - December 2022 – Confidential.

For details relating to our holistic approach to DER investment which includes our proposed Network Visibility and Solar Soak/Off-peak Conversion step changes, refer to Endeavour Energy - 10.40 DER Integration Strategy and Business Case - December 2022 – Public.

4.6.12 For each *step change* in forecast expenditure, where the *step change* is due to a change in a *regulatory obligation or requirement* provide:

(a) relevant variations or exemptions granted to Endeavour Energy during the previous regulatory control period or the current regulatory control period;

(b) any relevant compliance audits Endeavour Energy conducted during the previous regulatory control period or the current regulatory control period.

(c) with reference to specific clauses of the relevant legislative instrument(s), the:

  (i) previous regulatory obligation or requirement; and

  (ii) how the changed regulatory obligation or requirement is driving the step change.

Not applicable noting we have not included a step change in our 2024-29 proposal for the change in NSW licence conditions or Security of Critical Infrastructure (SOCI) Act at this stage.

4.7 Ancillary network services

4.7.1 Provide a description of each ancillary network service listed in the Standardised ancillary network services model published by the AER.

Despite reducing the number of ANS fees from the 2019-24 period, we propose to provide all of our current ANS services in the 2024-29 regulatory control and have not proposed any changes to the description of these existing services.

We have proposed the following four new ANS services for the 2024-29 period.

Service	Fee/Quote	Service Description
Network tariff change request	Fee	When a customer or retailer requests an alteration to an existing network tariff (for example, a change from an Inclining Block Tariff or a Time of Use tariff to a capacity tariff), the NSW distributors conduct tariff and load analysis to determine whether the customer meets the relevant tariff criteria. The NSW distributors also process changes in both their IT and market systems to reflect the tariff change.
Pole Holds	Quote	Pole holding activities to maintain the stability of the pole and safety where excavation works are undertaken (e.g. ground boring or digging under a footpath). Where an existing in-service Endeavour Energy pole is required to be held in place due to existing or expected instability of the pole or pole footing, only Endeavour Energy directed contractors or Endeavour Energy staff are permitted to perform this work.
Customer Data Request - Other	Quote	Provision of data other than metering or consumption data in excess to that provided as a regulatory requirement at the the request of a customer or authorised agent working on their behalf of the customer.
High load escorts - Preliminary studies	Quote	Planning transportation route paths for high vehicular loads to avoid temporary relocation of overhead mains.

Furthermore, we have proposed minor amendments relating to the names of the disconnection and reconnection service fees below to clarify that a separate fee will be charged for the disconnection and for the subsequent reconnection:

- Disconnections or Reconnections (Meter Box);
- Disconnections or Reconnections (Pole Top / Pillar Box);
- Disconnections or Reconnections (Site Visit); and
- Disconnections or Reconnections at Pole Top / Pillar Box - Site Visit.

For further details, refer to:

- Section 14.4 of our Regulatory Proposal; and
- Endeavour Energy - 14.07 ANS Pricing Model - January 2023 – Public.

4.8 Public lighting services

4.8.1 Specify which items are capex and opex for each year of the current regulatory control period and forecast for the forthcoming regulatory control period.

Our public lighting model distinguishes opex and capex items. Please refer to Endeavour Energy - 14.06 Public Lighting Pricing Model - January 2023 – Public.

In summary:

Capex

1. All expense under Non-Contestable Street Lighting projects;
2. Gift tax paid on Contestable Street Lighting Projects;
3. Replacement of condemned column/bracket;
4. Replacement of a column during an impact; and
5. Replacement of a luminaire as an improvement to the old luminaire e.g. obsolete technology new efficient technologies.

Opex

1. Condition based maintenance.
2. Fault and emergency. Streetlight outage reporting
3. Routine column inspection / patrol.
4. Replacement of a like for like luminaire.
5. Routine LED luminaire cleaning.

4.8.2 Provide unit costs for the current regulatory control period and forecast for the forthcoming regulatory control period for:

(a) luminaires;

(b) dedicated street lighting *poles*;

(c) brackets;

(d) photoelectric cells;

(e) labour rate (per hour); and

(f) miscellaneous materials.

For unit costs for current regulatory period, please refer to our revised public lighting pricing model submitted to the AER as part of our revised regulatory proposal for the 2019-24 regulatory control period, noting the public lighting prices in the model were approved in the AER's 2019-24 final decision.

For forecast unit costs for the forthcoming regulatory control period, refer to Endeavour Energy - 14.06 Public Lighting Pricing Model - January 2023 – Public.

4.8.3 Provide the depreciation period in years for each type of luminaire.

20 years for all types of luminaires except LED luminaires where it is 16 years.

4.8.4 Provide the bulk change cycle in years for lamps and photoelectric cells.

In response to the preferences of our customers to upgrade lamps to LEDs, Endeavour Energy remains committed to replacing lamps with LEDs during the 2024-29 period. Due to these LED upgrades we do not have a bulk replacement program for like-for-like lamp replacements.

In relation to PE cells, we do not have a bulk change plan or program.

4.8.5 Provide details of the average replacement age of each type of luminaire.

It is assumed to be 20 years for all luminaires except for LED luminaires where it is expected to be 16 years.

4.8.6 Provide the number of luminaires, by type, for the current and forthcoming regulatory control periods.

Refer to Endeavour Energy - 14.06 Public Lighting Pricing Model - January 2023 – Public.

4.8.7 Provide the number of luminaires, poles and brackets replaced per year, for the current and forthcoming regulatory control periods.

Refer to Endeavour Energy - 14.06 Public Lighting Pricing Model - January 2023 – Public.

4.8.8 Provide details, including assumptions used, for any other costs that are incurred for the provision of public lighting services.

Other direct or indirect costs which are incurred at regular interval mainly relate to traffic control management during installation/repair on major roads.

4.8.9 Provide the reasons for assumptions underpinning the proposed charges as set out in the models and/or modelling for public lighting for the forthcoming regulatory control period provided in response to 4.2.5(d) of this notice.

Where appropriate, the key assumptions underpinning our capex and opex forecasts also apply to the build-up of our proposed public lighting prices as set out in the public lighting model. Refer to Endeavour Energy - 0.08 Certified Key Assumptions - January 2023 – Public.

The basis of assumptions are specified in further detail in Chapter 14 of our regulatory proposal. These relate predominantly to satisfying our public lighting obligations and responding to customer preferences. These are reflected in our Public Lighting Management Plan. Refer to Endeavour Energy - 14.08 Public Lighting Management Plan - July 2021 – Public.

In regard to obligations, our public lighting model assumes compliance with the following:

- NSW Public Lighting Code which we must comply with as part of our distribution licence conditions;
- Customer nominated requirements within the range of services offered;
- AS/NZS1158 series of standards for lighting of roads and public places;
- Electricity Supply Act 1995;
- Endeavour Energy electrical safety rules; and
- Endeavour Energy General Terms and Conditions for connection of public lighting assets.

In regard to responding to customer preferences, our pricing model reflects:

- the latest available benchmark labour rates and fleet rates; and
- a reduced LED cleaning maintenance cycle from 10 years to 6 years.

Refer to Endeavour Energy - 14.06 Public Lighting Pricing Model - January 2023 – Public.

4.8.10 For public lighting services, specify the number of customers in each year of the current regulatory control period, and forecast for the forthcoming regulatory control period.

There are currently 31 public lighting accounts that are billed each month during the current regulatory control period. It is expected to remain same for the forthcoming regulatory control period.

4.9 Incentive schemes

Efficiency benefit sharing scheme

4.9.1 For the purposes of applying the *efficiency benefit sharing scheme*:

(a) identify all cost categories proposed to be excluded from the operation of the efficiency benefit sharing scheme;

As identified in EBSS regulatory template 7.5 of Endeavour Energy - RIN0.03 Reset RIN Workbook 3 – EBSS - January 2023 – Public; and Section 9.2.2 of our regulatory proposal, Endeavour Energy is proposing to exclude the following categories of opex for the purposes of calculating EBSS:

- debt raising costs;
- demand management innovation allowance (DMIA);
- within period changes in accounting standards; and
- movement in provisions.

(b) explain for each cost category identified the reasons for the proposed exclusion.

The EBSS allows costs to be excluded that are not forecast using a single year revealed cost approach. On this basis, we have removed debt raising costs and the demand management innovation allowance (DMIA) from the operation of the EBSS. We believe excluding these costs better achieves the requirements of clause 6.5.8 of the NER.

Provisions reflect liabilities that are uncertain in timing or amount. Changes in assumptions or expectations underpinning these future liabilities may lead to movements in the value of these provisions. Our decision to exclude movements from provisions is informed by the AER's 2015 final determination and the Australian Competition Tribunal's 2016 ruling on the matter.

Endeavour Energy accepts that changes in provisions will not be treated as actual opex for EBSS calculations. By excluding movements in provisions we are maintaining a consistent approach to the treatment of accruals towards the EBSS.

Changes in accounting standards, like changes in capitalisation practices, reflect reporting changes rather than genuine efficiency gains or losses. We therefore propose to report opex for EBSS purposes on a consistent manner with the accounting practices underlying the opex allowance (i.e. the base year opex). Instead, we will give effect to accounting standard changes in deriving the forecast opex for the following period so as to not distort the operation of the incentive schemes.

Service target performance incentive scheme and customer service incentive scheme

4.9.2 If Endeavour Energy proposes to apply an incentive design under the AER's Customer Service Incentive Scheme, this proposal must meet the requirements under clause 3.3 of the Customer Service Incentive Scheme.

We do intend to replace the customer service component of the STPIS with a small scale incentive scheme; a CSIS. F details on how this proposal satisfies the requirements of the CSIS guideline, refer to Endeavour Energy - 9.02 CSIS Proposal - January 2023 – Public and Section 9.5 of our Regulatory Proposal.

4.10 Indicative impact on annual electricity bills

4.10.1 For the purposes of calculating the impact of *Endeavour Energy's regulatory proposal* on the annual electricity bill of typical *residential* and business *customer*s in New South Wales, provide the data source for each input used for the calculation.

Refer to:

- Endeavour Energy - RIN0.05 Reset RIN Workbook 5 – Indicative Bill Impact - January 2023 – Public; and
- Endeavour Energy - RIN1.03 Indicative Bill Impact - Data Sources - January 2023 – Public for the data sources.

4.11 Proposed tariff structure statement

4.11.1 Provide and describe the methodology and assumptions used to prepare the long run marginal cost estimates in Endeavour Energy's tariff structure statement.

Endeavour Energy has developed LRMC estimates for both import and export tariffs.

Our LRMC methodology is outlined in section 3.2 of the Tariff Structure Statement (TSS) and section 7.2 of the explanatory statement that accompanies the TSS. Refer to Endeavour Energy – 0.14 Tariff Structure Statement – January 2023 - Public and Endeavour Energy – 0.15 Tariff Structure Explanatory Statement – January 2023 - Public.

The import LRMC Model is provided at Endeavour Energy – 0.16 Import LRMC model – January 2023 – Public.

The export LRMC Model is provided at Endeavour Energy – 0.17 Export LRMC model – January 2023 – Public.

4.11.2 Describe the relationship between the expenditure, demand and other inputs (as appropriate) used in the model provided under this section and the expenditure, demand and other forecasts (as appropriate) provided as part of the building block proposal for the *forthcoming regulatory control period*.

Our LRMC methodology is outlined in section 3.2 of the Tariff Structure Statement (TSS) and section 7.2 of the explanatory statement that accompanies the TSS. Refer to Endeavour Energy – 0.14 Tariff Structure Statement – January 2023 - Public and Endeavour Energy – 0.15 Tariff Structure Explanatory Statement – January 2023 - Public.

Section 2.6 of our explanatory statement that accompanies the Tariff Structure Explanatory Statement demonstrates how our future tariff strategy is integrated with our network planning to ensure that our forecast expenditure plan reflects the use of the network our tariffs incentivise.

4.11.3 If Endeavour Energy calculates the long run estimate cost estimates using a method different from the Average Incremental Cost method, Endeavour Energy must provide all inputs, definitions and sources for inputs, a description of the methodology, and calculations for every stage of the methodology in the in the materials submitted to the AER.

Endeavour Energy uses the Average Incremental Cost method.

4.11.4 Describe the methods and assumptions used to derive the disaggregated *capex* beyond the *forthcoming regulatory control period*. Provide any model(s) used to derive such *capex*.

Import LRMC (7.7.1.1):

The capital expenditure (capex) forecast used to calculate import LRMC is derived from the capex forecast provided in Endeavour Energy – RIN0.01 Reset RIN Workbook 1 – Forecast – January 2023 – Confidential, regulatory template 2.1, tables 2.1.1 and 2.1.7.

In calculating LRMC and populating table 7.7.1.1, Endeavour Energy undertook a review of the individual capex programs that aggregate to the total capex proposal. Programs deemed to have no impact on LRMC calculations have been excluded, these include programs related to:

- Pilots and trials
- Power quality
- Resilience
- Network monitoring; and

- Reliability compliance.

Overheads have been reduced in accordance with the reduction in direct network capex amounts outlined above.

There is no direct mathematical relationship that explains the annual variance between regulatory templates 7.7 and 2.1.

For disaggregated capex values beyond the forthcoming regulatory control period, Endeavour Energy has used the average value of each individual capex program over the FY25 to FY29 regulatory control period.

Export LRMC (7.7.1.2):

The capex forecast used to calculate export LRMC is sourced from the capex forecast provided in Endeavour Energy – RIN0.01 Reset RIN Workbook 1 – Forecast – January 2023 – Confidential, regulatory template 7.8, table 7.8.2.

For capex values beyond the forthcoming regulatory control period, Endeavour Energy has used the average value over the FY25 to FY29 regulatory control period.

4.11.5 Describe the methods and assumptions used to derive the disaggregated *opex* beyond the *forthcoming* regulatory *control period*. Provide any model(s) used to derive such *opex*.

Import LRMC (7.7.2.1):

For the purpose of calculating operating expenditure (opex) as it relates to the calculation import LRMC, Endeavour Energy has assumed an annual opex amount equal to 2.4% of the corresponding years capex used in the calculation of import LRMC.

The derivation of the 2.4% figure is provided in the LRMC Model as provided at Endeavour Energy – 0.16 Import LRMC model – January 2023 – Public. It is a function of opex to RAB and the proportion of opex deemed avoidable.

This methodology applies for opex values beyond the forthcoming regulatory control period.

Export LRMC (7.7.2.2):

The opex forecast used to calculate export LRMC is sourced from the capex forecast provided in Endeavour Energy – RIN0.01 Reset RIN Workbook 1 – Forecast – January 2023 – Confidential, regulatory template 7.8, table 7.8.1.

For opex values beyond the forthcoming regulatory control period, Endeavour Energy has used the average value over the FY25 to FY29 regulatory control period.

4.11.6 Describe the methods and assumptions used to derive the disaggregated demand beyond the forthcoming *regulatory control period*. Provide any model(s) used to derive such demand.

Import LRMC (7.7.3.1):

The demand forecast used to calculate LRMC is derived from the demand forecast provided in Endeavour Energy – RIN0.01 Reset RIN Workbook 1 – Forecast – January 2023 – Confidential, regulatory template 5.4, table 5.4.1.

The LRMC calculation is based Diversified MW (50% POE) demand.

In calculating LRMC and populating regulatory template 7.7.3.1, Endeavour Energy has excluded major customer demand as the majority of network costs related to incremental changes to a major customer's demand are funded by that major customer directly.

Demand values beyond the forthcoming regulatory control period are sourced from the 2023 Summer Demand Forecast (SDF) which extends to FY32. The 2023 SDF is provided in Endeavour Energy – 7.01 2023-2032 Summer Demand Forecast – August 2022 – Public

Export LRMC (7.7.3.2):

The peak export power unlocked by our proposed export expenditure program is calculated using a model of our network that simulates two-way flows across our low voltage assets.

Endeavour Energy's DER Integration Strategy and associated modelling is provided in Endeavour Energy – 10.40 DER Integration Strategy and Business Case – December 2022 – Public.

This model is used for export power forecasts in support of our export LRMC model for years both within and beyond the forthcoming regulatory control period.

4.12 Rate of return

4.12.1 For the purposes of assessing *Endeavour Energy's* proposal we require it to provide 'placeholder' averaging periods which will be made public and have been used to calculate an indicative rate of return in *Endeavour Energy's regulatory proposal*.

For the cost of debt, our placeholder averaging period is:

- the 10 days commencing from 4 October 2022.

For the risk-free rate, our placeholder averaging period is:

- 16 September to 17 October 2022.

For more details on our proposed rate of return refer to Endeavour Energy - 12.01 Rate of Return Model - January 2023 – Public and Chapter 12 of our Regulatory Proposal.

4.13 Regulatory asset base

4.13.1 If the value of the *regulatory asset base* as at the start of the *forthcoming regulatory control period* is proposed to be adjusted because of changes to *asset* service classification, provide details including relevant supporting information used to calculate that adjustment value.

We have not proposed to adjust the value of the regulatory asset base as at July 1, 2024 (the start of the next regulatory control period) to account for changes in the asset service classification.

Service classification changes between regulatory control periods as detailed in the AER's framework and approach paper are relatively minor and do not relate to standard control services that would require us to make adjustments to the RAB.

4.13.2 Provide details of any departure in the allocation of actual *capex*, *asset* disposal and *customer contribution* values across *asset* classes in the *roll forward model* from those reported in the Annual Reporting RIN for the relevant *regulatory years* and the reasons for that departure.

The allocation of actual capex, asset disposal and customer contribution values across asset classes is consistent between the RFM and those reported in the Annual Reporting RIN.

This is with the exception of the treatment of lease capitalisation costs for the 2019-24 period. At the commencement of the 2019-24 period the previous accounting standard for leases, AASB 117 Leases, was replaced by AASB 16 Leases which included a new requirement for a lessee to recognise assets and liabilities for the rights and obligations created by leases. This approach is considered to provide a more faithful representation of a lessee's assets and liabilities and greater transparency of a lessee's financial leverage and capital employed.

Specifically, AASB 16 Leases requires lease liabilities and the corresponding right of use asset to be capitalised and recognised in the balance sheet. In the income statement, lease payments are replaced by a depreciation expense on the asset and an interest expense on the lease liability. The new standard applied to annual reporting periods beginning on or after 1 January 2019.

For financial accounting purposes, Endeavour Energy adopted the changes from this date with operating lease contracts recognised in the balance sheet as an asset and liability to be amortised over the life of the lease contract.

For our regulatory accounts we were not in a position to adopt this change in standard at the time of our 2019-24 proposal. We have therefore been unable to report leases in our regulatory accounts on a consistent basis with our statutory accounts. For FY20 and FY21 the lease amounts were treated as an 'Adjustment' between the Statutory and Regulatory accounts.

From FY25, we intend to apply a consistent approach per the principles of regulatory accounting and therefore have the value of capitalised leases reflected in our RAB. The leased asset will then be depreciated at a rate equivalent to the term of the contract (or remaining term of the contract in the case of existing leases).

Importantly, our intent to adopt the new accounting standard has been discussed with our Regulatory Reference Group (RRG) and accepted on the provision adopting the changes does not deliver any unintended windfall gains at the expense of customers.

We have therefore engaged with the AER, along with other networks, to confirm the appropriate treatment of mid-period accounting changes for the 2019-24 period. From a regulatory perspective, it has been demonstrated that a revenue neutral approach is to align the accounting treatment of the expenditure within a period to the treatment underpinning the approved expenditure. Accordingly, we will treat lease costs as opex for the remainder of the 2019–24 regulatory control period (FY22 – FY24) and commence reporting them as capitalised expenditure from 1 July 2024. Specifically:

- for EBSS purposes leases are reported within opex for the 2019-24 period consistent with the treatment of leases used to set the 2019-24 opex allowance;
- for opex forecasting purposes leases are removed from opex and instead included as part of the capex forecast; and
- for leases entered into during the 2019-24 period a final year adjustment will be made to establish an opening asset base for the 2024-29 period.

For the latter, we have calculated the present value of leases entered into over the 2019-24 period and assigned remaining asset lives to reflect the average remaining term of the relevant contract. Over the 2019-24 period we entered into leases on an annual basis for Motor Vehicles and our CBD Office. We also entered into a lease for our new Parramatta head office during FY23.

For further details on the RFM adjustments, refer to.

- Endeavour Energy - 8.01 Lease Capitalisation - January 2023 – Public; and
- Endeavour Energy - 8.02 Lease RFM - January 2023 – Public.

4.14 Depreciation schedules

4.14.1 Identify any changes to standard asset lives for existing asset classes from the previous determination. Explain the reason(s) for each change and provide supporting information.

There have been no changes to the standard lives for existing asset classes between the current and forecast regulatory control periods.

4.14.2 Identify any changes in the post-tax revenue model to asset classes from the previous determination. Explain the reason(s) for using these new asset classes and provide supporting information on their proposed standard asset lives.

As discussed in 4.13.2 above, the accounting treatment of leases has changed following the introduction of AASB 16 Leases. We intend to align the regulatory accounting treatment with the statutory accounting treatment for the 2024-29 period (and beyond). This accounting change means that leases are now capitalised rather than expensed.

To facilitate this we propose the addition of two new asset classes being:

- Short term leases with a 5 year standard life – this covers leases pertaining to our Motor Vehicle fleet and our CBD head office; and
- Long term leases with a 10 year standard life – this covers our head office lease.

4.14.3 If any existing asset classes from the previous determination are proposed to be removed and their residual values to be reallocated to other asset classes in the post-tax revenue model, explain the reason(s) for the change and provide supporting information. This should include a demonstration of the materiality of the change on the forecast depreciation allowance.

No asset classes have been discontinued between the current regulatory control period and the forthcoming regulatory control period

4.15 Corporate tax allowance

4.15.1 Identify each change to standard tax *asset* lives for existing *asset* classes from the previous *determination*. Explain the reason(s) for the change and provide relevant supporting information, including Federal tax laws governing depreciation for tax purposes.

No changes have been made to standard tax asset lives for existing asset classes from the previous determination.

4.15.2 Identify each difference in the *capitalisation* of expenditure for regulatory accounting purposes and tax accounting purposes. Provide reasons and supporting calculations to reconcile any differences between the two forms of accounts.

Not applicable.

4.15.3 Please provide the following information regarding *immediate expensing capex* for *standard control services*:

(a) Explain the approach Endeavour Energy used to forecast its immediate expensing capex for the 2024–2029 regulatory control period as provided in the proposed post-tax revenue models.

(b) State if Endeavour Energy intends to change its tax policy on immediate expensing capex from its current policy.

We have forecast our immediate expensing of capex based on the average amount expensed immediately over the FY19-FY22 period. We do not intend to change our tax policy on immediate expensing capex from our current policy.

4.15.4 The *post-tax revenue model* applies the diminishing value (DV) method for tax depreciation purposes to all new depreciable *assets* except for certain *assets*. Where *Endeavour Energy* proposes *capex* associated with buildings and in-house software to be exempted from the DV method of tax depreciation, confirm that the proposal satisfies the following requirements:

(a) Buildings (capital works): Capex for buildings may be depreciated using the straight-line (SL) method if it satisfies the definition of a capital work under section 43.20 of the Income Tax Assessment Act 1997 (ITAA).

We can confirm that our proposal satisfies these requirements.

(b) In-house software: Capex for in-house software may be depreciated using the SL method if it satisfies the definition of in-house software under section 995.1 of the ITAA, and may be depreciated using the SL method, consistent with section 40.72 of the ITAA.

We can confirm that our proposal satisfies these requirements.

4.16 Related party transactions

4.16.1 Identify and describe all entities which:

(a) are a related party to Endeavour Energy and contribute to the provision of distribution services; or

(b) have the capacity to determine the outcome of decisions about *Endeavour Energy's* financial and operating policies.

Edwards A Pty Ltd as trustee for Edwards A Trust, Edwards O Pty Ltd as trustee for Edwards O Trust and Edwards U Pty Ltd as trustee for Edwards U Trust respectively hold a 50.4% share in each Partnership (Private Partners).

The State holds a 49.6% interest in each Partnership through a number of ERIC subsidiary entities (ERIC Partners).

The Private Partners and ERIC Partners have entered into a partnership deed for each of the Asset Partnership, Operator Partnership and Unregulated Partnership to govern the management and operation of the respective Partnerships.

4.16.2 Provide a diagram of the organisational structure depicting the relationships between all the entities identified in the response to this section 4.17.

A diagram of the group structure is provided at Endeavour Energy - RIN1.04 Group Structure - January 2023 - Public.

4.16.3 Identify:

(a) all arrangements or *contracts* between *Endeavour Energy* and any of the other entities identified in the response to this section 4.17 currently in place or expected to be in place during the *forthcoming regulatory control period* which relate directly or indirectly to the provision of distribution *services*; and

Nil.

(b) the service or services that are the subject of each arrangement or *contract*.

Not applicable.

4.16.4 For each service identified as the subject of each arrangement or *contract*:

(a) provide:

(i) a description of the process used to procure the service; and

(ii) supporting documentation including, but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, *contracts* between *Endeavour Energy* and the relevant provider.

Not applicable.

(b) explain:

(i) why that service is the subject of an arrangement or *contract* (i.e. why it is outsourced) instead of being undertaken by *Endeavour Energy* itself;

(ii) whether the services procured were provided under a standalone *contract* or provided as part of a broader operational agreement (or similar);

(iii) whether the services were procured on a genuinely competitive basis and if not, why not; and

(iv) whether the service (or any component thereof) was further outsourced to another provider by the *related party*.

Not applicable.

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