DRAFT DECISION
Evoenergy
Distribution Determination

2019 to 2024

Attachment 6

Operating expenditure

September 2018

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to Evoenergy for the 2019–2024 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme

Attachment 12 – Classification of services

Attachment 13 – Control mechanisms

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CCP 10	Consumer Challenge Panel, sub-panel 10
CPI	consumer price index
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
EBSS	efficiency benefit sharing scheme
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
F&A	framework and approach
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
RIN	regulatory information notice
RPP	revenue and pricing principles

6 Operating expenditure

Operating expenditure (opex) is the operating, maintenance and other non-capital expenses incurred in the provision of network services. Forecast opex for prescribed distribution services is one of the building blocks we use to determine a service provider's annual total revenue requirement.

This attachment outlines our assessment of Evoenergy's forecast opex for the 2019–24 regulatory control period.

6.1 Draft decision

Our draft decision is to include total forecast opex of $297.1 million ($2018–19) in Evoenergy's revenue for the 2019–24 regulatory control period. This is an increase of 12 per cent from Evoenergy's actual opex in the current regulatory control period, which allows for:

- additional efficient and prudent expenditure required to meet Evoenergy's expanded responsibilities for vegetation management under the *Utilities (Technical Regulation) Amendment Act 2017* (ACT), which took effect from 1 July 2018
- additional expenditure for demand management, which will support deferral of augmentation to Evoenergy's network
- expected increases in input costs (including the cost of labour), and in the costs of operating a larger network with more customers.

We used our standard 'base-step-trend' approach to develop our estimate.[1] The total opex forecast we have adopted in this draft decision starts with Evoenergy's actual costs in 2017-18 as a base year. We have then forecast growth in prices, output and productivity using our standard approach (with some refinement) and assessed Evoenergy's step changes in accordance with our *Expenditure forecast assessment guideline* (the Guideline).[2]

We do not accept the total forecast opex in Evoenergy's proposal. Our total forecast is 4.6 per cent lower than Evoenergy's proposal of $311.4 million ($2018-19). This is because:

- The efficient and prudent costs of complying with Evoenergy's expanded vegetation management responsibilities that we have included in our total forecast opex is $6.81 million lower than proposed by Evoenergy. This reflects our view—based on the information before us—that the prudent and efficient level of expenditure required to meet these new responsibilities is less than Evoenergy has put to us.

1 AER - Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013.

2 AER - Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013.

- Our forecast of expected increase in real labour prices in the ACT (price growth) is lower than proposed by Evoenergy. We have applied our standard approach by averaging growth in the wage price index for the ACT utilities industry forecast by Deloitte Access Economics and Evoenergy's consultant, BIS Oxford Economics. In contrast, Evoenergy only applied BIS Oxford Economics' forecasts.
- Our forecast of expected increases in the costs of operating a larger network (output growth) is lower than Evoenergy.

We have substituted our alternative estimate as the forecast opex in Evoenergy's revenue determination for the 2019–24 regulatory control period. The reasons for our draft decision are set out in further detail in section 6.4.

We note that, for the purpose of this draft decision, our rate of change applies a zero productivity growth forecast. This is consistent with Evoenergy's proposal, and has been our standard approach to forecasting the productivity component of our opex the rate of change in past decisions.

CCP10 submits that a zero productivity improvement over five years is not in the best interests of customers. CCP10 contends that:[3]

> … meeting the national energy objective (NEO) means that network businesses, including Evoenergy, need to be looking for positive productivity improvements each year, though not necessarily at the recent rate of opex productivity growth.

We are currently reviewing our approach to forecasting productivity.[4] This review may change our approach going forward. As part of this review we will consult with all distributors and any other interested stakeholders. We will take the outcome of this review into consideration in our final decision.

Evoenergy's forecast opex and our draft decision are set out in Table 6.1.

Table 6.1 Evoenergy's proposed opex and our draft decision ($ million, 2018–19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Evoenergy's proposed opex	59.8	61.0	62.3	63.6	64.7	311.4
AER draft decision	57.7	58.5	59.4	60.3	61.2	297.1
Difference	-2.1	-2.5	-2.9	-3.3	-3.5	-14.3

Source: Evoenergy, *Revenue proposal*, *Post tax revenue model (PTRM)*, January 2018; AER analysis

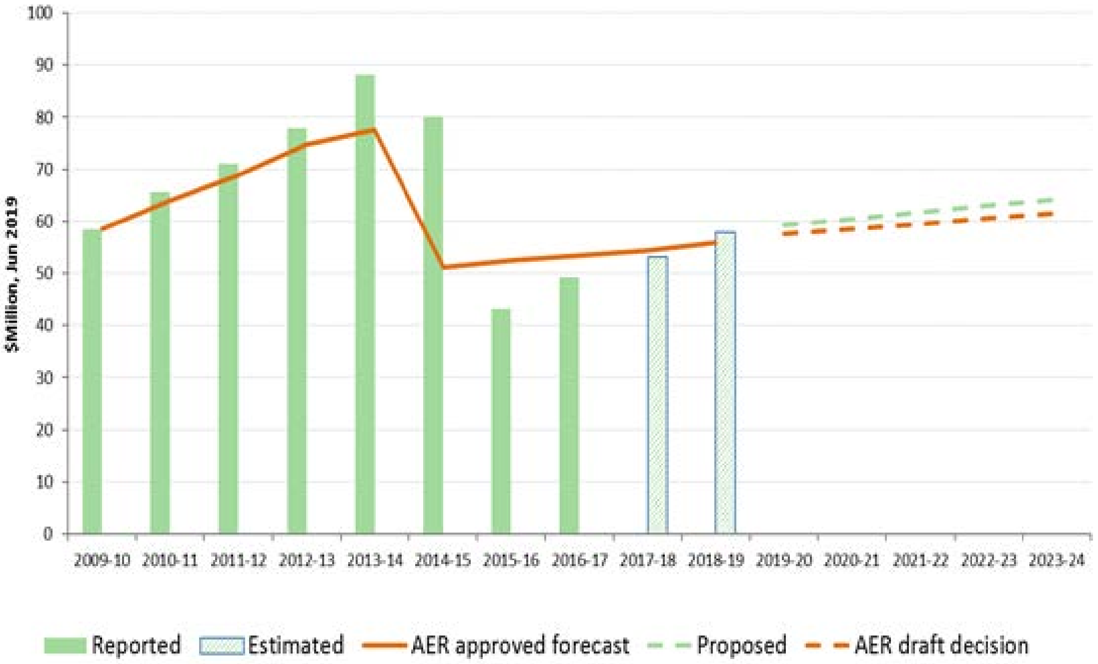
Note: Includes debt raising costs. Numbers may not add up to total due to rounding.

3 Consumer Challenge Panel (Subpanel 10), *CCP10 Response to Evoenergy regulatory proposal 2019–24 and AER issues paper*, May 2018, p.15.

4 See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-our-approach-to-forecasting-opex-productivity-growth-for-electricity-distributors

Figure 6.1 shows Evoenergy's opex forecast, its historical reported opex, our previous regulatory decisions and our draft decision forecast.

Figure 6.1 Historical and forecast opex ($ million, 2018–19)



6.2 Evoenergy proposal

Evoenergy's forecast opex is one of the key drivers of the increase in revenue it proposes for the 2019–24 regulatory control period. Evoenergy's proposed opex of $311.4 million ($2018–19) is an increase of 10.2 per cent from its actual and estimated opex for the 2014–19 regulatory control period.

Table 6.2 Evoenergy's proposed opex ($ million, 2018–19)

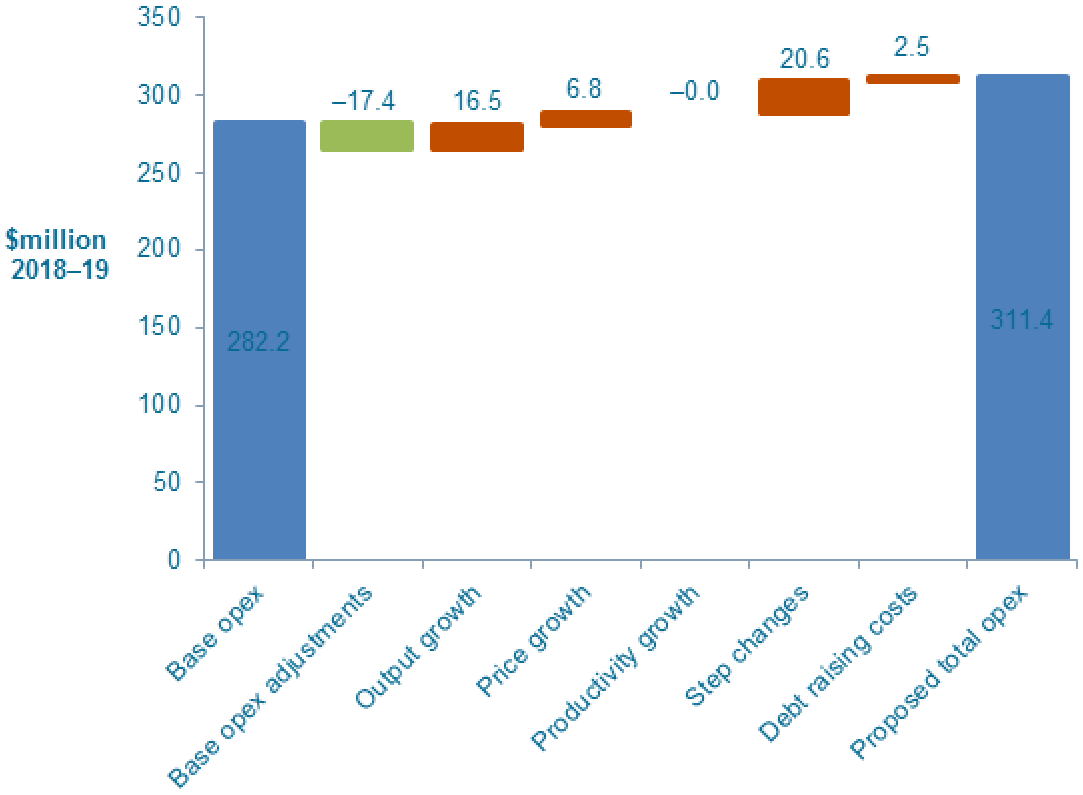
	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Opex excluding debt raising costs	59.26	60.47	61.81	63.08	64.24	308.85
Debt raising costs	0.50	0.50	0.50	0.51	0.51	2.53
Total opex	**59.77**	**60.97**	**62.31**	**63.59**	**64.74**	**311.38**

Source: Evoenergy regulatory proposal

Note: Numbers may not add up to total due to rounding.

Figure 6.2 provides a breakdown of Evoenergy's opex forecast into key components.

Figure 6.2 Evoenergy's opex forecast breakdown



Source: AER analysis.

Evoenergy stated that it has adopted our revealed cost approach to forecasting opex (the 'base-step-trend' approach). The key elements of Evoenergy's proposal are set out below.

- Evoenergy uses its estimated opex in 2017–18[5] (its base year), to derive a base opex of $282.2 million ($2018–19).
- Evoenergy has removed two non-recurrent costs from its base year opex, which it expects to incur in 2017–18 but not in future years.[6] This equates to an adjustment to the base opex of $17.4 million ($2018–19).
- Evoenergy then trends forward its base opex to account for:
    - Expected increases in real input prices, including forecast increases in labour costs and an increase in line with CPI for non-labour costs ($6.8 million, $2018–19).

[5] The actual opex for 2014–19 in Evoenergy's proposal includes its estimates of opex for 2017–18 and 2018–19. This will be updated later in the year when actual data becomes available. We will also make adjustments for movement in provisions.

[6] The base year adjustments are costs associated with implementation of Power of Choice reforms and the changes required by the AER's new Ring-fencing Guideline, which Evoenergy anticipates recovering as cost pass through events under the current 2014–19 determination.

- Forecast output growth, driven primarily by increased customer numbers, circuit line length and maximum demand, all of which can increase the cost to Evoenergy of operating its network ($16.5 million, $2018–19).
  - Forecast zero change in opex productivity over the regulatory period.[7]
- Evoenergy has included two step changes in its opex forecast:
  - $18.8 million ($3.8 million per annum) to meet the efficient costs of expanded vegetation management obligations following amendments to the *Utilities (Technical Regulation) Act 2014 (ACT)* passed in November 2017.
  - $1.8 million ($0.36 million per annum) in demand management costs to allow deferral of capex for the construction of a new substation at Strathnairn.
- Evoenergy has forecast $2.5 million ($2018–19) of debt raising costs. Debt raising costs are transaction costs incurred each time debt is raised or refinanced.

6.2.1 Submissions on Evoenergy's proposal

We received two submissions on Evoenergy's opex proposal; from the Consumer Challenge Panel (subpanel 10) (CCP10), and from the ACT Energy Consumer Policy Consortium. Where relevant, we will reference their submissions in our reasoning for our decision in section 6.4.

6.3 Assessment approach

Our role is to form a view about whether a business's forecast of total opex is reasonable. Specifically, we must form a view about whether a business's forecast of total opex 'reasonably reflects the opex criteria'.[8] In doing so, we must have regard to each of the opex factors specified in the NER.[9]

If we are satisfied the business's forecast reasonably reflects the criteria, we accept the forecast.[10] If we are not satisfied, we substitute an alternative estimate that we are satisfied reasonably reflects the opex criteria for the business's forecast.[11] In making this decision, we take into account the reasons for the difference between our alternative estimate and the business's proposal, and the materiality of the difference. Further, we consider interrelationships with the other building block components of our decision.[12]

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[7] The productivity of each distribution network is reported in the AER's annual benchmarking reports. See AER, *Annual benchmarking report - Electricity distribution network service providers*, November 2017.

[8] NER, cl. 6.5.6(c).

[9] NER, cl. 6.5.6(e).

[10] NER, cl. 6.5.6(c).

[11] NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

[12] NEL, s. 16(1)(c).

The *Expenditure forecast assessment guideline* (the Guideline) together with an explanatory statement set out our intended approach to assessing opex in accordance with the NER. [13] We published the Guideline and the associated explanatory statement in November 2013 following an extensive consultation process with service providers, network users, and other stakeholders. While the Guideline provides for greater regulatory predictability, transparency and consistency, it is not mandatory. However, if we make a decision that is not in accordance with the Guideline, we must state the reasons for departing from the Guideline.[14]

We apply the assessment approach outlined in the Guideline to develop our estimate of a business's total opex requirements (our alternative estimate). Our alternative estimate serves two purposes. First, it provides a basis for testing whether a business's proposal is reasonable. Second, we can use it as a substitute forecast if we determine a business's proposal does not reasonably reflect the opex criteria.

Below we further explain the principles that underpin this approach and provide a high-level overview of the 'base–step–trend' methodology.

6.3.1 Incentive regulation and the 'top-down' approach

Incentive regulation is designed to prevent network businesses from exploiting their natural monopoly position by setting prices in excess of efficient costs.[15] A key feature of the regulatory framework is that it is based on incentivising networks to be as efficient as possible. We apply incentive-based regulation across the energy networks we regulate, including electricity distribution networks. More specifically for opex, we rely on the efficiency incentives created by both ex ante revenue regulation (where an opex allowance is granted over a multi-year regulatory period) and the 'efficiency benefit sharing scheme' (EBSS).

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us, the regulator.[16]

Incentive regulation encourages regulated businesses to reduce costs below the regulator's forecast, in order to make higher profits, and ‘reveal’ their costs in doing so. The information revealed by the businesses allows us to develop better expenditure forecasts over time. Revealed opex reflects the efficiency gains made by a business over time. As a network business becomes more efficient, this translates to lower forecasts of opex in future regulatory periods, which means consumers also receive the benefits of the efficiency gains made by the business. Incentive regulation therefore aligns the business’s commercial interests with consumer interests.

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13 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013; AER, *Expenditure forecast assessment guideline*, *Explanatory statement*, November 2013.

14 NER, cl. 6.2.8(c)(1).

15 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 188.

16 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 189.

Our general approach is to assess the business's forecast opex over the regulatory control period at a total level, rather than to assess individual opex projects or programs. To do so, we develop an alternative estimate of total opex using a 'top-down' forecasting method, known as the 'base–step–trend' approach (section 6.3.2).[17]

Benchmarking a network business against others in the National Electricity Market (NEM) provides an indication of whether revealed opex can be adopted as 'base opex' and, if not, what our alternative estimate of base opex should be. While benchmarking is a key tool, we will use a combination of techniques to assess whether base opex reasonably reflects the opex criteria.[18] We may make a negative adjustment to the business's revealed opex if we find it is operating in a materially inefficient manner. Material inefficiency is a concept we introduce in our Guideline.[19] We consider a service provider is materially inefficient when it is not at or close to its peers on the efficient frontier. We define this more precisely in the context of economic benchmarking below.

Incentive regulation is designed to leave the day-to-day decisions to the network businesses.[20] It allows the network businesses the flexibility to manage their assets and labour as they see fit to achieve the opex objectives in the NER,[21] and more broadly, the National Electricity Objective (NEO).[22] This is consistent with the requirement that we consider whether *the total* opex forecast, and *not* the individual forecast opex components, reasonably reflects the opex criteria.[23]

The Australian Energy Market Commission (AEMC) supports this view of our role as the economic regulator. It stated: [24]

> The key feature of economic regulation of [distribution network service providers] in the NEM is that it is based on incentives rather than prescription…
>
> Importantly, under [incentive-based regulation], funding is not approved for [distribution network service providers'] specific projects or programs. Rather, a total revenue requirement is set, which is based on forecasts of total efficient expenditure. Once a total revenue is set, it is for the [business] to decide which suite of projects and programs are required to deliver services to consumers while meeting its regulatory obligations…

17 A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting individual projects or categories to build a total opex forecast from the 'bottom up'.

18 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p 32.

19 AER, *Expenditure Forecast Assessment Guideline*, November 2013, p. 22.

20 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, pp. 27–28.

21 NER, cl. 6.5.6(a).

22 NEL, s. 7.

23 NER, cl. 6.5.6(c).

24 AEMC, *Contestability of energy services, Consultation paper*, 15 December 2016, p. 32.

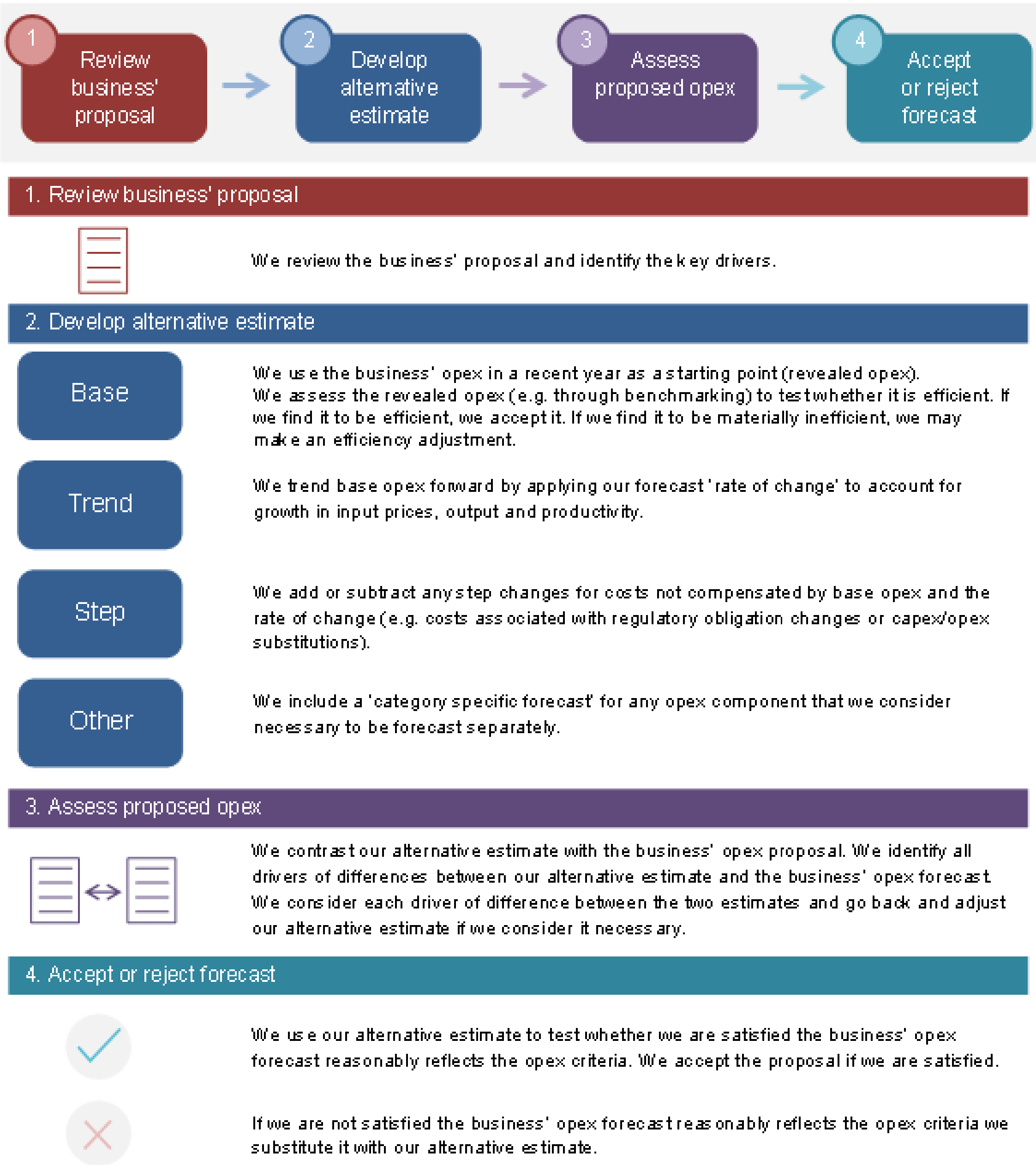
6.3.2 Base–step–trend forecasting approach

As a comparison tool to assess a business's opex forecast, we develop an alternative estimate of the business's total opex requirements in the forecast regulatory control period, using the base–step–trend forecasting approach.

If the business adopts a different forecasting approach to derive its opex forecast, we develop an alternative estimate and assess any differences with the business's forecast opex.

Figure 6.3 summarises the base–step–trend forecasting approach.

Figure 6.3 Our opex assessment approach



Base opex

If we find the business is operating efficiently, our preferred methodology is to use the business's historical or 'revealed' costs in a recent year as a starting point for our opex forecast.

We do not simply assume the business's revealed opex is efficient. It may include an ongoing level of inefficient expenditure. We use our benchmarking results[25] and other assessment techniques to test whether the business is operating efficiently.

We consider revealed opex in the base year is generally a good indicator of opex requirements over the next regulatory period because the level of *total opex* is relatively stable from year to year. This reflects the broadly predictable and recurrent nature of opex.

A business may experience fluctuations in particular categories of opex, and the composition of total opex can change, from year to year. While many operation and maintenance activities are recurrent and non-volatile, some opex projects follow periodic cycles that may or may not occur in any given year, and some opex projects are non-recurrent.

Even if disaggregated opex categories have high volatility, the total opex varies to a lesser extent because new or increasing components of opex are generally offset by decreasing costs or discontinued opex projects. Further, we expect the regulated business to manage the inevitable 'ups and downs' in the components of opex from year to year—to the extent they do not offset each other—by continually re-prioritising its work program, as would be expected in a workably competitive market. Our incentive-based, revealed cost, framework incentivises them to do so.

Rate of change

We trend base opex forward by applying our forecast 'rate of change'. We estimate the rate of change by forecasting the expected growth in input prices, outputs and productivity. We consider that the rate of change takes into account almost all drivers of opex growth.

We forecast input price growth using a composition of labour and non-labour price changes forecasts. Labour costs represent a significant proportion of a distribution business's costs.[26] To determine the input price weights for labour and non-labour prices, we have regard to the input price weights of a prudent and efficient benchmark business. Consistent with incentive regulation, this provides the business an incentive to adopt the most efficient mix of inputs throughout the regulatory control period.

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25 AER, *Annual benchmarking report—Electricity distribution network service providers*, November 2017.

26 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 49.

We forecast output growth to account for annual increase in output. The output measures used should be the same measures used to forecast productivity growth.[27] Productivity measures the change in output for a given amount of input. If the output measures differ from the productivity measures, they would be internally inconsistent and we cannot compare them like for like.

The output measures we typically use for distribution businesses are energy delivered, ratcheted maximum demand, weighted entry and exit connections and circuit length. We do not typically adjust forecast output growth for economies of scale because we account for these in our forecast of productivity growth.

Our forecast of productivity growth represents our best estimate of the shift in the industry 'efficiency frontier'.[28] We generally base our estimate of productivity growth on recent productivity trends across the industry. However, if we consider historic productivity growth does not represent 'business-as-usual' conditions we do not use it to forecast future productivity growth.

Our standard approach to forecasting the productivity component of our opex the rate of change in past decisions has been to apply zero productivity growth. In its submission to our issues paper, CCP10 submits that a zero productivity improvement over five years is not in the best interests of customers. CCP10 contends that:[29]

> … meeting the national energy objective (NEO) means that network businesses, including Evoenergy, need to be looking for positive productivity improvements each year, though not necessarily at the recent rate of opex productivity growth.

We are currently reviewing our approach to forecasting productivity.[30] This review may change our approach going forward. As part of this review we will consult with all distributors and any other interested stakeholders. We will take the outcome of this review into consideration in our final decision.

Step changes and category-specific forecasts

Lastly, we add or subtract any components of opex that are not adequately compensated for in base opex or the rate of change, but which should be included in the forecast total opex to meet the opex criteria.[31] These adjustments are in the form of 'step changes' or 'category-specific forecasts'.

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27 AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 23.

28 AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 24.

29 Consumer Challenge Panel (Subpanel 10), *CCP10 Response to Evoenergy regulatory proposal 2019–24 and AER issues paper*, May 2018, p.15.

30 See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-our-approach-to-forecasting-opex-productivity-growth-for-electricity-distributors

31 AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 24.

Step changes

Step changes should not double count costs included in other elements of the total opex forecast. As explained in the Guideline, the costs of increased volume or scale should be compensated for through the output growth component of the rate of change and it should not become a step change.[32] In addition, forecast productivity growth may account for the cost of increased regulatory obligations over time—that is, 'incremental changes in obligations are likely to be compensated through a lower productivity estimate that accounts for higher costs resulting from changed obligations.'[33] Therefore, we consider only new costs that do not reflect the historic 'average' change as accounted for in the productivity growth forecast require step changes.[34]

To increase its maximum allowable revenue, a regulated business has an incentive to identify new costs not reflected in base opex or costs increasing at a greater rate than the rate of change. It has no corresponding incentive to identify those costs that are decreasing or will not continue. Information asymmetries make it difficult for us to identify those future diminishing costs. Therefore, simply demonstrating that a new cost will be incurred—that is, a cost that was not incurred in the base year—is not a sufficient justification for introducing a step change. There is a risk that including such costs would upwardly bias the total opex forecast.

The test we apply is whether the step change is needed for the opex forecast to achieve the opex objectives in the NER.[35] Our starting position is that only exceptional circumstances would warrant the inclusion of a step change in the opex forecast because they may change a business's fundamental opex requirements.[36] Two typical examples are:

- a material change in the business's regulatory obligations
- an efficient and prudent capex/opex substitution opportunity.

We may accept a step change if a material 'step up' or 'step down' in expenditure is required by a network business to prudently and efficiently comply with a new, binding regulatory obligation that is not reflected in the productivity growth forecast.[37] This does not include instances where a business has identified a different approach to comply with its existing regulatory obligations that may be more onerous, or where there is increasing compliance risks or costs the business must incur to comply with its regulatory obligations. Usually when a new regulatory obligation is imposed on a business, it will incur additional expenditure to comply. The business may be expected

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32 AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 24.

33 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

34 AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 24.

35 NER, cl. 6.5.6(a).

36 AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 24.

37 AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 11.

to continue incurring such costs associated with the new regulatory obligation into future regulatory periods; hence, an increase in its opex forecast may be warranted.

We expect the business to provide evidence demonstrating the material impact the change of regulatory obligation has on its opex requirements, and robust cost–benefit analysis to demonstrate the proposed step change expenditure is prudent and efficient to meet the change in regulatory obligations.[38] We stated in the explanatory statement accompanying the Guideline:[39]

> [Network services providers] will be expected to justify the cost of all step changes with clear economic analysis, including quantitative estimates of expected expenditure associated with viable options. We will also look for the [Network services providers] to justify the step change by reference to known cost drivers (for example, volumes of different types of works) if cost drivers are identifiable. If the obligation is not new, we would expect the costs of meeting that obligation to be included in revealed costs. We also consider it is efficient for [Network services providers] to take a prudent approach to managing risk against their level of compliance when they consider it appropriate (noting we will consider expected levels of compliance in determining efficient and prudent forecast expenditure).

By contrast, proposed opex projects designed to improve the operation of the business, which we consider as discretionary in the absence of any legal requirement, should be funded by base opex and trend components, together with any savings or increased revenue that they generate—rather than through a step change. Otherwise, the business would benefit from a higher opex forecast and the efficiency gains.[40]

We may also accept a step change in circumstances where it is prudent and efficient for a network business to increase opex in order to reduce capital costs. We would typically expect such capex/opex trade-off step changes to be associated with replacement expenditure.[41] The business should provide robust cost–benefit analysis to clearly demonstrate how increased opex would be more than offset by capex savings.[42]

In the absence of a change to regulatory obligations or a legitimate capex/opex trade-off opportunity, we would accept a step change under limited circumstances. We would consider whether the costs associated with the step change are unavoidable and material—such that base opex, trended forward by the forecast rate of change, would be insufficient for the business to recover its efficient and prudent costs. We would also consider whether the business would continue to incur the costs of a proposed step change in future regulatory periods.

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38 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, pp. 51–52; AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 11.

39 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

40 AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 11.

41 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 74.

42 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

Category specific forecasts

A category specific forecast may be justified if, as a result of including a specific opex category in the base opex, total opex becomes so volatile that it undermines our assumption that total opex is relatively stable and follows a predictable path over time.

We may also use category specific forecasts to avoid inconsistency or double counting within our determination. We have typically included category specific forecasts for debt raising costs, the demand management incentive allowance (DMIA) and guaranteed service levels (GSL) payments. There are specific reasons for forecasting these categories separately from base opex. For example, we forecast debt raising costs separately to provide consistency with the forecast of the cost of debt in the rate of return building block of allowable revenue. For DMIA, we forecast these costs separately because we fund them through a separate building block.

Absent such exceptions, we expect that base opex, trended forward by the rate of change, will allow the business to recover its prudent and efficient costs. Again, the business has demonstrated its ability to operate prudently and efficiently at that level of opex while meeting its existing regulatory obligations, including its safety and reliability standards. We consider it is reasonable to expect the same outcome looking forward. Some costs may go up, and some costs may go down—so despite potential volatility in the cost of certain individual opex activities, total opex is generally relatively stable over time. As we stated above in relation to step changes, a business has an incentive to inflate its total opex forecast by identifying new and increasing costs, but not declining costs. Consequently, there is a risk that providing a category specific forecast for opex items identified by the business may upwardly bias the total opex forecast. By applying our revealed cost approach consistently and carefully scrutinising any further adjustments, we avoid this potential bias.

6.3.3 Interrelationships

In assessing Evoenergy's total forecast opex we took into account other components of its revenue proposal, including:

- the impact of cost drivers that affect both forecast opex and forecast capex. For instance, forecast labour price growth affects forecast capex and our forecast of forecast price growth used to estimate the rate of change in opex
- its proposed capex for the construction of zone substation at Strathnairn, which underpins Evoenergy's demand management opex/capex trade-off step change
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- concerns of electricity consumers identified in the course of Evoenergy's engagement with consumers.

6.4 Reasons for draft decision

Our draft decision is to include total forecast opex of $297.1 million ($2018–19) in Evoenergy's revenue for the 2019–24 regulatory control period. We consider that this forecast reasonably reflects the opex criteria. Our total forecast is 4.6 per cent lower than Evoenergy's proposal of $311.4 million ($2018–19). This is because:

- The efficient and prudent cost of complying with Evoenergy's expanded vegetation management responsibilities that we have included in our total forecast opex is $6.8 million lower than proposed by Evoenergy. This reflects our view that the prudent and efficient level of expenditure required to meet these new responsibilities is less than Evoenergy has put to us.
- Our forecast of expected increase in real labour prices in the ACT (price growth) is $3.4 million lower than proposed by Evoenergy.
- Our forecast of expected increases in the costs resulting from operating a larger network (output growth) is $4.5 million lower than Evoenergy.

For these reasons, we do not accept that Evoenergy's proposed forecast reasonably reflects the opex criteria. We have adopted our alternative estimate as the forecast opex in Evoenergy's revenue determination for the 2019-24 regulatory control period.

Table 6.3 compares the differences between our alternative estimate and Evoenergy's opex proposal.

Table 6.3 Our alternative estimate compared to Evoenergy's proposal ($ million, 2018–19)

	Evoenergy	Our alternative estimate	Difference
Based on reported opex in 2017-18	282.2	283.0	0.8
Base year adjustments	-17.4	-17.6	-0.3
Output growth	16.5	12.0	-4.5
Price growth	6.8	3.5	-3.4
Productivity growth	0.0	0.0	0.0
Step changes	20.6	13.8	-6.8
Category specific forecasts	0.0	0.0	0.0
Debt raising costs	2.5	2.4	-0.1
Total opex	311.4	297.1	-14.3

Source: Evoenergy, Revenue proposal - forecast SCS opex model, 31 January 2018; AER analysis.

Note: Numbers may not add up to total due to rounding.

We discuss the components of our alternative estimate below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

6.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that Evoenergy would need for the safe and reliable provision of electricity services over the 2019–24 regulatory control period.

Evoenergy proposes to use its estimated opex for 2017–18 as the base to forecast opex over the 2019–24 regulatory control period. It estimates that this opex will be $52.98 million ($2018–19). We have assessed the efficiency of Evoenergy's estimated opex in 2017–18 using multiple techniques and information sources, including its revealed opex over the 2014–19 regulatory control period, recent economic benchmarking analysis, and a review of its expenditure cost categories.

As outlined in our Expenditure Assessment Forecast Guideline, our preferred approach for forecasting opex is to use a revealed cost approach.[43] This is because opex is largely recurrent and stable at a total level between regulatory periods. Where a distributor is responsive to the financial incentives under the regulatory framework, the actual level of opex it incurs should provide a good estimate of the efficient costs required for it to operate a safe and reliable network and meet its relevant regulatory obligations.

The revealed data shows that Evoenergy achieved significant reductions in opex between 2012–13 and 2016–17. This was driven primarily by a restructuring program that saw Evoenergy decrease its workforce by 133 full-time equivalent staff (FTEs). Evoenergy’s opex between 2015–16 and 2018–19 is consistent with the opex set in our April 2015 final decision. Evoenergy expects that it will be able to sustain these savings into the next regulatory period.[44]

We cross-checked Evoenergy's revealed costs with economic benchmarking to see if there is any evidence that its opex materially inefficient. Our most recent economic benchmarking analysis indicates that Evoenergy's opex in 2017–18 is not materially inefficient.

Taken together, this indicates that Evoenergy's actual opex in 2017–18 should provide a reasonable estimate of the prudent and efficient level of base opex that Evoenergy would need for the safe and reliable provision of electricity services. Therefore we propose to rely on Evoenergy's opex in 2017–18 as our base year for the purposes of forecasting opex over the 2019–24 regulatory control period.[45]

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43 AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p.31.

44 Evoenergy, *Regulatory proposal 2019-24, Attachment 6: Operating Expenditure*, January 2018, p.6-2.

45 Table 6.3 shows that our alternative opex forecast is $0.8 million higher than Evoenergy's forecast, even though we and Evoenergy have both adopted the same base year value. This is because Evoenergy reports its base year opex in nominal dollars and our opex modelling escalates this to 30 June 2019 dollars. Evoenergy has assumed a slightly lower rate of inflation than we have in our opex modelling.

The following sections set out our assessment of Evoenergy's revealed opex and our economic benchmarking analysis.

Evoenergy revealed costs over 2014–19

This section examines Evoenergy's revealed costs between 2012–13 (its proposed base year for its 2014–19 revenue proposal) and 2018–19 (the end of the current regulatory period).

In April 2015, we made a decision on Evoenergy's opex forecast for the 2014–19 regulatory control period. In our decision, we found that the actual opex incurred by Evoenergy in its proposed base year of 2012–13 was materially greater than what a prudent and efficient network service provider would incur in delivering safe and reliable network services to customers. As a result, we found that Evoenergy's actual opex for this year could not be used as a basis to forecast opex for the 2014–19 regulatory control period.

Consistent with the NER, we substituted a lower base opex amount as the starting point of our substitute estimate for the 2014–19 regulatory control period. We relied on one of our economic benchmarking models to estimate our substitute base opex amount. Our base year was 35 per cent lower than Evoenergy's opex in 2012–13.

Our April 2015 decision was overturned by the Australian Competition Tribunal, and we were required to remake our decision in accordance with the Tribunal's directions. On 24 July 2018, Evoenergy submitted a proposal for the remaking of our 2014–19 decision. Evoenergy proposed to accept our April 2015 opex forecast with the addition of labour redundancy costs that it considered was necessary to reduce its opex to efficient levels. We are currently in the process of making our decision on this proposal.

Evoenergy faced a very strong incentive to reduce its costs over the 2014–19 regulatory control period given that our opex forecasts were significantly below its actual costs at the start of the regulatory period. Evoenergy also faced uncertainty around its final revenue allowance and the outcome of the appeals process. This uncertainty is noted by Evoenergy's in its proposal:[46]

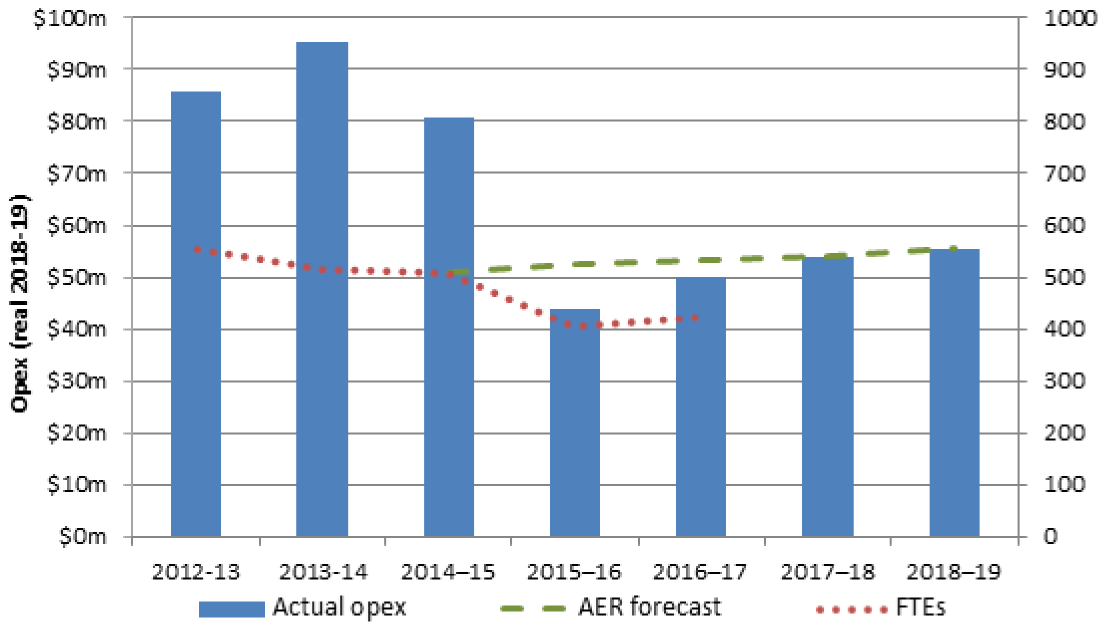
> Over the 2014–19 regulatory control period Evoenergy has been through significant change and reform as a business. The extent and speed of these changes was necessitated by the AER's 2015 final decision on opex and the uncertainty surrounding the outcome, following an appeal to the Australian Competition Tribunal and Federal Court on several matters, including opex, which resulted in the AER's decision being set aside.

As shown in Figure 6.4, Evoenergy reduced its total opex by 45 per cent between 2014–15 and 2015–16. Over the same period, it has also reduced its permanent

46 Evoenergy, *Regulatory proposal for the ACT electricity distribution network 2019–24, Attachment 6: Operating Expenditure*, January 2018, p. 6-2

workforce by 24 per cent. This significant reduction meant that its opex in 2015–16 and 2016–17 was below the opex forecast in our April 2015 final decision. For 2017–18 and 2018–19, Evoenergy estimates that its opex will be at the same level that we forecast in our April 2015 final decision.

Figure 6.4 Evoenergy's opex, AER forecast opex in 2015 final decision, including movements in average staffing levels (ASLs)



Source: AER 2015 final decision; Evoenergy Annual RIN; Evoenergy 2019–24 regulatory proposal; Annual reports.

Note: Actual opex has been normalised by excluding metering and ancillary costs prior to 2014–15. Opex in 2017–18 and 2018–19 are estimates taken from Evoenergy's 2019–24 regulatory proposal opex model and regulatory RIN. Evoenergy's estimate for 2018–19 includes additional opex related to its proposed opex step-change for new vegetation management obligations within its 2019–24 proposal. For the purposes of this chart, we have removed this additional vegetation management opex because it relates to new obligations that were not in place at the time of our 2015 final decision.

In its regulatory proposal for the 2019–24 regulatory control period, Evoenergy stated that it has achieved its opex savings through:[47]

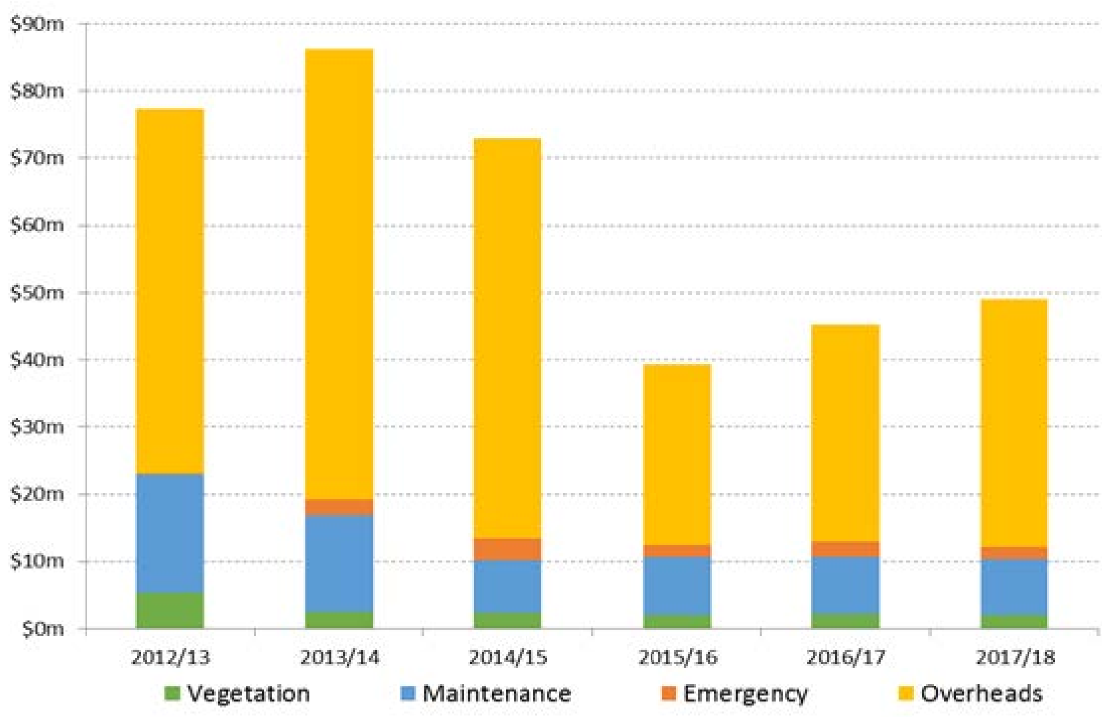
- an extensive restructuring of the workforce including redundancies
- re-engineering and asset optimisation to reduce the program of works
- savings on vegetation management using new light detection and ranging (LiDAR) technology and improved contractual arrangements

[47] Evoenergy, *Regulatory proposal 2019-24, Attachment 6: Operating Expenditure*, Attachment 6: Operating Expenditure, January 2018, p.6-8.

- investment in systems technology to drive smarter operation of the network, including improvements in automation and asset management practices, and
- a reduction in overtime and staff training.

This has led to reductions across all of Evoenergy's major cost categories. Figure 6.5 shows that, between 2012–13 and 2016–17, it has reduced opex across vegetation management, maintenance and overhead costs. Emergency services opex has increased but this is potentially driven by Evoenergy’s reduction in overall maintenance costs, which may necessitate more reactive maintenance during outages and emergency situations.

Figure 6.5 Evoenergy's opex cost breakdown



Source: Evoenergy Category Analysis RIN; Reset RIN; AER analysis.

Labour costs are the single largest operating costs incurred by Evoenergy across all of the above cost categories. In our 2015 final decision, we found Evoenergy had higher than efficient labour costs.[48] Since that time, it has improved the efficiency of its labour costs by reducing averaging staffing levels. Evoenergy's proposal states:[49]

> Evoenergy undertook an extensive restructuring process, resulting in a considerable reduction in Evoenergy’s workforce. Average staffing levels were reduced by 20 per cent between 2013/14 and 2016/17. Higher levels of opex in

[48] AER, *Final Decision ActewAGL distribution determination 2015–16 to 2018 –19, Attachment 7 – Operating Expenditure*, April 2015, pp. 7-54 and 7-55.

[49] Evoenergy, *Regulatory proposal 2019-24, Attachment 6: Operating Expenditure*, January 2018, p.6-8.

> 2013/14 and 2014/15 were driven by costs to undertake this restructuring, mostly relating to redundancy payments.

Evoenergy states that the reductions in its labour force was critical to achieving the lowest possible operating expenditure for the 2014–19 regulatory control period while achieving the operating expenditure objectives:[50]

> While Evoenergy implemented a broad program of transformation across the business, it is the workforce restructure that delivered the most significant and immediate cost savings. Without the workforce restructure, the transformation program would not have delivered the savings required to move to the significantly lower levels of operating expenditure incurred in the 2014-19 period, nor would it have guaranteed that resources were focused on the areas of the business necessary to maintain the safety and reliability of the network and therefore would not have reflected the efficient and prudent costs of achieving the operating expenditure objectives.

As observed in Figure 6.5, Evoenergy has also reduced its vegetation management costs (excluding allocated overheads) by 58 per cent between 2012–13 and 2016–17. While this cost category is not a material component of Evoenergy's total opex, our April 2015 decision found that it was a source of inefficiency. Evoenergy states that it has improved its vegetation contract procurement procedures since 2014 when it moved from a per hour basis to a fixed price contract. This has reduced overall trimming costs by 50 per cent.[51] It also states that it has reduced its vegetation management costs through the use of new technology (LiDAR).[52]

Finally, Evoenergy's proposal suggests that it will be able to sustain the level of cost savings in opex achieved by 2017–18 into the next 2019–24 regulatory period:[53]

> The 2019–24 regulatory control period will see Evoenergy consolidate the efficiencies achieved and continue its evolution as it adapts to the ongoing and dynamic National Electricity Market reforms and technological advancements driving industry change for all market participants. This continuous efficiency drive will be achieved while maintaining the quality, reliability and security of supply of SCS to its customers, and Evoenergy’s forecast opex reflects efficient costs.

Economic benchmarking analysis

We use economic benchmarking as supporting analysis to cross-check whether Evoenergy's revealed opex shows signs of material inefficiency. Benchmarking broadly refers to the practice of comparing the economic performance of a group of service providers that all provide the same service as a means of assessing their relative

50 Ibid, p. 3.

51 Evoenergy, response to AER information request 21, 7 May 2018, p.7.

52 Evoenergy, *Regulatory proposal 2019-24, Attachment 6: Operating Expenditure*, January 2018, p.6-8.

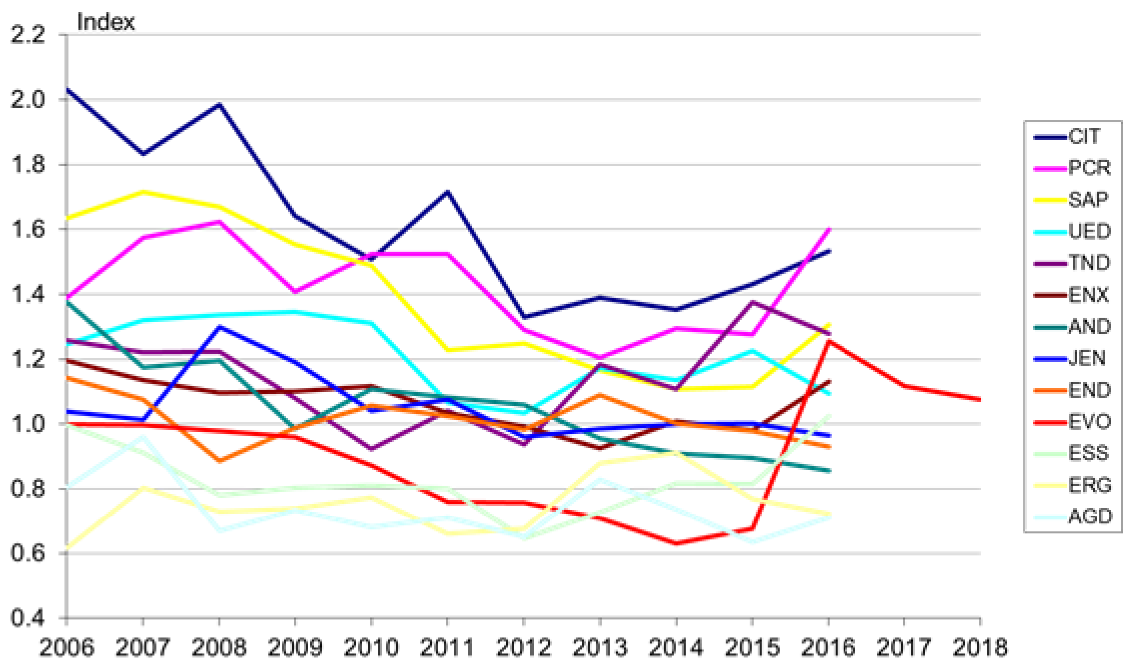
53 Evoenergy, *Regulatory proposal 2019-24, Attachment 6: Operating Expenditure*, January 2018, p.6-2.

performance. Our 2017 annual benchmarking report includes information about the use and purpose of economic benchmarking, and details about the techniques we use to benchmark the efficiency of DNSPs in the NEM.[54]

Economic benchmarking of Evoenergy's opex in 2017–18 indicates that it is not materially inefficient. This provides further evidence that Evoenergy's 2017–18 opex reflects a reasonable estimate of the prudent and efficient level of base opex for the purposes of forecasting opex over the 2019–24 regulatory control period.

Figure 6.6 presents the results of opex multilateral partial factor productivity (MPFP), one of our primary economic benchmarking techniques. This allows for the comparison of opex productivity levels between service providers and across time.[55] When opex productivity improves, this implies there is improvements in efficiency. The chart shows Evoenergy’s own performance (the red line) and that of other networks in the NEM over time.

Figure 6.6 Opex multilateral partial factor productivity



Source: AER 2017 annual benchmarking report (updated in 2018)

Note: The chart uses Evoenergy’s actual opex up to 2016-17 and opex forecasts for 2017-18, and results for all other networks up until 2016 (from our 2017 published benchmarking report).

54 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2017. Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/annual-benchmarking-report-2017

55 The opex multilateral partial factor productivity (MPFP) technique examines the contribution of operational expenditure to overall productivity. Productivity is a measure of the quantity of output produced from the use of a given quantity of inputs.

This opex MPFP analysis indicates that Evoenergy has significantly improved its opex productivity over the 2014–19 regulatory control period. Between 2014–15 and 2015–16, Evoenergy improved its measured opex productivity from the second worst within the NEM to the fifth best. This coincides with the 45 per cent reduction in opex, as shown in Figure 6.4.

According to Evoenergy, these significant reductions caused some deterioration in network reliability which adversely impacted its reliability performance.[56] Between 2015–16 and 2017–18 (as currently estimated), Evoenergy increased its opex by 23 per cent. This led to a corresponding reduction in its in opex productivity and, by 2017–18, Evoenergy is estimated to be ranked 7th amongst distribution network service providers in the NEM.

Notwithstanding these recent reductions in Evoenergy’s opex productivity, Evoenergy remains amongst the middle group of efficient networks in terms of opex efficiency. While these MPFP results do not account for some differences in operating environment factors, Evoenergy's improvement in productivity suggests that it is no longer materially inefficient compared to its NEM peers.

We have further examined the efficiency of Evoenergy's 2017–18 opex using the results of our econometric benchmarking models. Our econometric models are published as part of our annual benchmarking report, and were developed by our consultant Economic Insights. The results presented in this section reflect the most recent benchmarking results that we intend to publish in our 2018 benchmarking report.

As noted by Economic Insights, the econometric cost function models produce average opex efficiency scores for the period over which the models are estimated. The results we are using in this section reflect average efficiency scores over the 2012–17 period. It may take some time for improvements in efficiency by previously poorly performing distributors to be reflected in the efficiency scores, such as Evoenergy's improved opex productivity between 2014–15 and 2015–16.

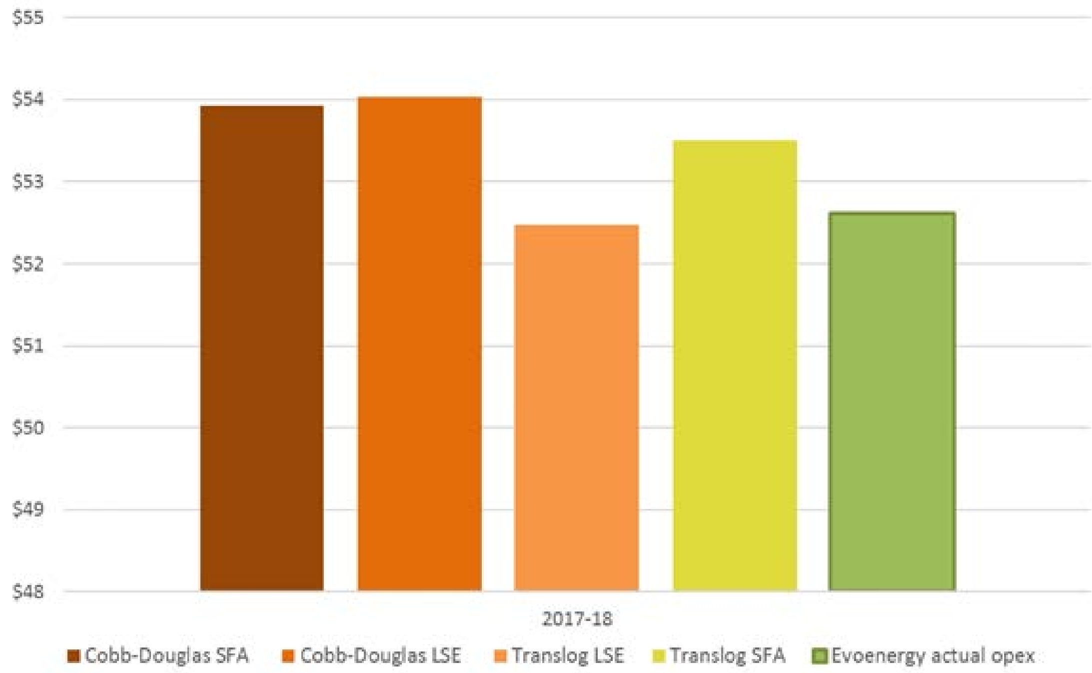
To use the econometric results to assess the efficiency of opex in the 2017–18 base year, we can estimate the efficient costs from a benchmark efficient service provider operating in Evoenergy's circumstances. We do this by determining the efficient costs on average over the 2012–17 period based on the results of our econometric models and an appropriate margin for differences in operating environments. We then roll the efficiency results forward to the base year using a rate of change.

Figure 6.7 presents the estimated efficient opex from four of our econometric models, and compares this to Evoenergy's actual opex in 2017–18. This provides us with a range of estimated efficient opex, using different estimation techniques and opex cost functions. This shows that Evoenergy's actual opex in 2017–18 falls within the range of these different estimates of efficient opex. This is consistent with our observations of

56 Evoenergy, submission to AER opex issues paper, p. 3

Evoenergy's opex MPFP, which suggested that Evoenergy's opex in 2017–18 is not materially inefficient compared to its NEM peers.

Figure 6.7 Estimated efficient opex in 2017-18 (m, $2018-19)



Source: AER analysis

Evoenergy's proposal includes some additional benchmarking analysis which it says supports its proposed base year:[57]

> This analysis demonstrates that estimated efficiency scores are very sensitive to the model specification (CD versus translog and least squares estimation versus SFA) and data choices (such as excluding outlier firms and excluding selected international data), resulting in a range of efficiency scores from 35 per cent to 57 per cent for Evoenergy. The efficiency scores are used to determine a range for the target roll-forward opex by applying the same methodology as the AER applied in its 2015 final decision to identify the comparison point, adjust for operating environment factors (excluding the adjustment for capitalisation policies which has been addressed by backcasting opex using the current CAM), calculating the midpoint efficient opex and trending the midpoint efficient opex to 2017/18. The resulting range for the target opex is between $37 million and $58 million. Evoenergy's 2017/18 base year opex of $53 million falls within this range. Therefore, to the extent that weight can be placed on the AER's top-down benchmarking approach, the

57 Evoenergy, *Regulatory proposal 2019-24, Attachment 6: Operating Expenditure*, January 2018, p.6-12.

results suggest that Evoenergy's base year opex reasonably reflects the opex criteria.

Base opex adjustments

To finalise our estimate of base opex for the initial year, we make the following adjustments to Evoenergy's revealed 2017-18 opex:

- Removing non-recurrent costs relating to implementation of Power of Choice reforms and the changes required by the AER's new Ring-fencing Guideline. Evoenergy anticipates recovering these costs as cost pass through events within the 2014–19 regulatory control period.[58]
- Removing $45,116 of outage and switching costs.[59] Evoenergy had incorrectly allocated this cost to its standard control services opex when it undertook urban tree clearances pursuant to private contracts it had with the ACT Government in 2017–18. This is explained further in our analysis of Evoenergy's proposed vegetation management step change in section 6.4.3.
- Removing movements in provisions. This ensures we base our alternative estimate on the actual costs incurred by the business, and not provisions the business set aside for liabilities it has yet to pay out. Evoenergy will report its actual movements in provisions for 2017–18 when it submits its regulatory accounts in October 2018. We will update this estimate in our final decision.

6.4.2 Rate of change

Having determined an efficient starting point, or base opex, we trend it forward to account for the forecast growth in prices, output and productivity. We refer to this as the rate of change.

For the purpose of the draft decision, we have largely applied our standard approach to forecasting the rate of change. Specifically we have:

- Used a weighted average of forecast labour price growth and non-labour price growth to determine price growth
- Used output weights derived from the results of the four benchmarking models we presented in our 2017 annual benchmarking report. This is a refinement of our previous approach, which used the weights from a single econometric model.
- Applied a zero productivity growth forecast.

We have forecast an average annual rate of change of 1.49 per cent, compared to Evoenergy's forecast of 2.13 per cent. The reasons for our forecast, and the difference compared to Evoenergy's forecast, are set out below.

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[58] Evoenergy, *Regulatory proposal 2019-24, Attachment 6: Operating Expenditure*, January 2018, p.6-10.

We are currently conducting an industry-wide review of our approach to forecasting productivity. This is a result of our observations that productivity has grown over three per cent each year (since 2012) across the distribution industry. This is consistent with our expectations that distributors would make positive productivity growth in the medium to long term (historical productivity growth has been negative).

Further, we have received feedback from various CCPs suggesting we review these aspects of the rate of change. The CCP have submitted that meeting the national energy objective (NEO) means that network businesses need to be looking for positive productivity improvements each year and recommended we reconsider our zero productivity forecast.[60]

Our productivity forecasting review may change our approach to forecasting productivity going forward. As part of this review, we will consult with all distributors and any other interested stakeholders.[61] Stakeholders will be given multiple opportunities to engage in the review and provide us with their views. Our final decision for Evoenergy will take the outcome of this review into consideration.

Forecast price growth

We have included forecast real average annual price growth of 0.40 per cent in developing our alternative opex estimate. This increases opex from the base year by $3.5 million ($2018–19). In contrast, Evoenergy forecast price growth of 0.69 per cent.

Our price growth forecast is a weighted average of forecast labour price growth and non-labour price growth:

- To forecast labour price growth, we have used the average growth in the wage price index (WPI) for the Australian Capital Territory utilities industry forecast by Deloitte Access Economics and Evoenergy's consultant, BIS Oxford Economics.[62] In contrast, Evoenergy only applied WPI forecast by BIS Oxford Economics.[63]
- To forecast non-labour price growth, we, like Evoenergy, have applied the forecast change in CPI.[64]

We and Evoenergy have applied the same weights to account for the proportion of opex that is labour and the proportion that is non-labour (59.7:40.3). Our reasons for adopting these weights are set out in our 2017 Economic Benchmarking report.[65]

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[60] Consumer Challenge Panel subpanel 10, Response to Evoenergy regulatory proposal 2019–24 and AER issues paper, 16 May 2018, p.15; Consumer Challenge Panel subpanel 13, Issues paper Power and Water electricity network revenue proposal 2019–24, 16 May 2018, p.6.

[61] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-our-approach-to-forecasting-opex-productivity-growth-for-electricity-distributors

[62] Deloitte Access Economics, *Labour Price Growth Forecasts Prepared for the Australian Energy Regulator*, 19 July 2018, Table vii, p. xiv; Evoenergy, *Regulatory proposal 2019–24, Attachment 6: Operating Expenditure*, January 2018, p.6-14.

[63] Evoenergy, *Regulatory proposal 2019–24, Attachment 6: Operating Expenditure*, January 2018, p.6-14.

[64] Evoenergy, *Regulatory proposal 2019–24, Attachment 6: Operating Expenditure*, January 2018, p.6-14.

Forecast output growth

We have included forecast average annual output growth of 1.09 per cent in developing our alternative estimate of forecast opex. This increased our alternative estimate by $12.0 million ($2018–19). Our output growth forecast is an average of the output growth rates forecast using the specification and weights from the four models presented in our 2017 annual benchmarking report. These models are:[66]

- opex multilateral partial factor productivity (MPFP)
- Cobb Douglas stochastic frontier analysis (SFACD)
- Cobb Douglas least squares estimation (LSECD)
- Translog least squares estimation (LSETLG).

Table 6.4 shows the output specification and weights from each model as reflected in the 2017 annual benchmarking report.

Table 6.4 Outputs specification and weights derived from economic benchmarking models

Output	MPFP	SFACD	LSECD	LSETLG
Customer numbers	45.8%	77.1%	69.7%	59.8%
Circuit length	23.8%	9.7%	11.2%	11.2%
Ratcheted maximum demand	17.6%	13.1%	19.1%	28.9%
Energy throughput	12.8%			

Source: AER analysis; Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report*, 31 October 2017

We have forecast our year on year output growth by:

- Calculating four model specific output growth rates, each as a weighted average growth in specified outputs. For example, the output growth rate based on the MPFP model is a weighted average of growth in customer numbers, circuit length, ratcheted maximum demand and energy throughput; and that based on SFACD model is a weighted average of growth in customer numbers, circuit length and ratcheted maximum demand.
- Calculating the average of four model specific output growth rates.

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65 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report*, 31 October 2017, pp. 1–2.

66 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report*, 31 October 2017, p. 1 and pp. 18–20.

This is a refinement of our previous approach, which only used the output weights from a single econometric model (the SFACD model). Full details of our refined approach to forecast output growth are set out in our opex model, which is available on our website.

CCP10 recently raised concerns about the weight applied to customer numbers under our previous approach. In its submission on Evoenergy's regulatory proposal, CCP 10 stated that trend customer growth accounts for a significant part of Evoenergy's output growth. It noted that this outcome flows from our underlying econometric model. CCP 10 encouraged us to test whether our output growth rates are reasonable, and whether too much weight has been allocated to customer numbers when we forecast output growth.[67]

We have reviewed the output weights derived from the four models presented in our economic benchmarking reports over the period 2014–17. Our review shows that the weight of customer numbers derived from the SFACD model is relatively high and it has increased over time. The customer numbers weight does not increase as much in the other econometric models (LSECD and LSETLG).[68]

Our refined approach, which uses an average of the output weights from the four models, helps to address concerns raised by the Australian Competition Tribunal (the Tribunal) in its merits review of our 2015 decision for NSW electricity determinations. The Tribunal raised concerns about our reliance on a single model and in remitting the NSW decisions directed us to use a broader range of modelling and benchmarking.[69]

We are currently updating our economic benchmarking analysis to incorporate data for 2016–17. We will publish this analysis in our 2018 annual benchmarking report in late November 2018. In our final decision, we will update our forecast output growth to reflect the 2018 economic benchmarking results.

We note we have adopted Evoenergy's forecasts for its outputs of customer numbers, circuit line length and energy throughput. However, for ratcheted maximum demand we have adopted a different measure to Evoenergy.

To forecasting output growth, we use the measure of maximum demand that is consistent with our standard approach:

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67 Consumer challenge Panel (subpanel 10), *Response to Evoenergy regulatory proposal 2019-24 and AER issues paper* - 16 May 2018, p. 10.

68 We note that the weights from the MPFP model have remained constant over time. The MPFP model is a functional output index number model. It is the standard practice with such models to estimate the output cost shares initially (using cost functions based on the data available) and to then leave these shares constant for an extended period. This allows changes in the MPFP scores to reflect changes in performance (and possibly exogenous factors) only. Our 2018 annual benchmarking report will update outputs weights for the MPFP model.

69 Applications by Public Interest Advocacy Centre Ltd and Essential Energy [2016] ACompT 3, direction 1(a). The Tribunal's decision was upheld by the Full Federal Court. For more details, see: Australian Energy Regulator v Australian Competition Tribunal (No 2) [2017] FCAFC 79, [285].

> Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE forecast at the transmission connection point – MW measure

This measure of maximum demand is consistent with the measure used by the benchmarking models to derive the output weights (as outlined above). We do this to ensure consistency between the weighting we apply to each output growth factor and the relevant measure of that output.

In comparison, Evoenergy's proposed forecast growth in ratcheted maximum demand is based on:

> Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE forecast at the transmission connection point – MVA measure.

This is a different measure of maximum demand than we use in our standard approach to opex forecasting and economic benchmarking. Evoenergy's forecast maximum demand under this measure will peak over the 2019-24 regulatory control period, which will result in growth in ratcheted maximum demand over the period. In comparison, under our measure, maximum demand peaked in 2015 and is not forecast to exceed this peak over the 2019-24 regulatory control period. Hence, we forecast zero growth in ratcheted maximum demand.

Forecast productivity growth

For the draft decision, we have forecast zero productivity growth in our alternative opex forecast. This is consistent with Evoenergy's regulatory proposal, and our standard approach to forecasting productivity.[70]

In response to Evoenergy's proposal, CCP10 recommended we reconsider our standard approach of forecasting zero per cent productivity growth. CCP10 states that a zero productivity improvement over five years is not in the best interests of customers. CCP10 contends that meeting the national energy objective (NEO) means that network businesses, including Evoenergy, need to be looking for positive productivity improvements each year, though not necessarily at the recent rate of opex productivity growth.[71]

We note that there will be an opportunity to consider this further as a part of industry wide productivity forecasting consultation process outlined above and as a part of the final decision.

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70 Evoenergy, *Regulatory proposal 2019-24, Attachment 6: Operating Expenditure*, January 2018, p.6-16.

71 Consumer Challenge Panel (Subpanel 10), *CCP10 Response to Evoenergy regulatory proposal 2019–24 and AER issues paper*, May 2018, p.15.

6.4.3 Step changes

We add (or subtract) step changes for any costs are not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria.[72] In the absence of a change to regulatory obligations or a legitimate capex/opex trade-off opportunity, we would accept a step change under limited circumstances.

Evoenergy proposed two step changes to base opex totalling $20.6 million ($2018–19) or 6.7 per cent of its total opex forecast. These step changes are:

- $18.8 million opex to comply with new vegetation management regulations that commence from 1 July 2018.
- $1.8 million in demand management opex to defer the construction of a new zone substation serving the suburb of Strathnairn.

We have included a step change for Evoenergy's new vegetation management obligations. Our estimate of the efficient costs of complying with this obligation is $12.0 million ($2018–19), which is 36 per cent less than proposed by Evoenergy. We consider that this reflects the prudent and efficient costs of complying with its new obligations over the 2019–24 regulatory control period, as explained below.

We have also included Evoenergy proposed demand management step change.

Vegetation management and private electrical infrastructure inspections step change

Evoenergy has stated that its vegetation management costs will increase from 1 July 2018 due to a change in its legislative obligations. On 8 November 2017, the *Utilities (Technical Regulation) Act 2014 (ACT)* was amended to transfer the responsibility of vegetation clearing on unleased land in urban areas of the ACT from the ACT Government to Evoenergy. In addition, Evoenergy also became responsible for inspection of private poles on rural leased properties. This added responsibility came into effect on 1 July 2018.

Evoenergy has proposed a step change of $3.8 million per annum (or $18.8 million across the 2019–24 regulatory period) to meet these increased legislative obligations. This step change represents a 6 per cent increase in Evoenergy's annual total opex, and a 150 per cent increase to its annual vegetation management expenditure.[73] Evoenergy submits that:

> … the step changes proposed are prudent and efficient and are necessary to meet the opex objectives in the NER (Rule 6.5.6 (a)), namely to comply with all applicable regulatory obligations or requirements associated with the provision

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[72] AER, *Expenditure forecast assessment guideline for electricity transmission*, November 2013, p. 24.

[73] This is based on the AER's analysis of Evoenergy's vegetation management costs in its Category Analysis RIN data over the 2014-15 to 2017-18 period.

> of standard control services. If these changes in costs are not included, Evoenergy's current operating costs will not reasonably reflect the operating expenditure criteria as per 6.5.6 (c) of the NER.

We have included a step change for forecast costs of complying with Evoenergy's new vegetation management obligations (and private electrical infrastructure inspections). We agree that an increase in Evoenergy's operating costs is required to comply with its new regulatory obligation. However, our forecast is $2.4 million ($2018–19) per annum, which is 36 per cent lower than Evoenergy's regulatory proposal. We consider that this reflects the prudent and efficient costs of complying with its new obligations over the 2019–24 regulatory control period, including a realistic expectation of the cost inputs required. In reaching this alternative estimate, we have relied upon the information provided by Evoenergy in its proposal supplemented with responses to our information requests, including updated volume and cost estimates.

Are additional vegetation management costs required?

Evoenergy currently manages all vegetation near electricity infrastructure within defined rural areas and Bushfire Abatement Zones under past agreement with the Commonwealth and ACT governments. This responsibility covers 21,090 spans over a three year tree cutting program.[74] Transport Canberra and City Services (TCCS) has previously been the ACT Government Department that was responsible for clearing vegetation near electricity infrastructure on unleased land within defined urban areas. This responsibility is now transferred to Evoenergy under the new legislation.[75]

These new urban areas of responsibility cover an additional 16,918 vegetation spans,[76] which is an 80 per cent increase to the existing vegetation spans it is responsible for in designated rural and bushfire areas. Evoenergy states that the transfer of responsibility will involve the management of vegetation in the following areas:[77]

- Designated urban area (or built-up areas)
- Bushfire risk urban areas including Canberra's urban green belts (which are currently managed under the existing ACT strategic Bushfire Management Plan 2014–19)
- Parkland and Nature Reserves that fall under the definition of urban fringe as areas considered to be of high bushfire risk (e.g. Mount Majura, Redhill).

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74 Evoenergy, response to AER information request #21, 7 May 2018, p.2.

75 Evoenergy, *Regulatory Proposal 2019-24, Appendix 6.1 Vegetation and private electrical infrastructure – operating expenditure step change 2019-24 (PUBLIC)*, January 2018, p. 3

76 Evoenergy, *Regulatory Proposal 2019-24, Appendix 6.1 Vegetation and private electrical infrastructure – operating expenditure step change 2019-24 (PUBLIC)*, January 2018, p. 11

77 Evoenergy, *Regulatory Proposal 2019-24, Appendix 6.1 Vegetation and private electrical infrastructure – operating expenditure step change 2019-24 (PUBLIC)*, January 2018, p. 11

Evoenergy submits that:[78]

> These costs will be incurred as a result of changes to Evoenergy's regulatory obligations. Evoenergy have assessed current internal capacity and determined that, due to the order of magnitude increase in requirements to meet the new obligations, Evoenergy is unable to absorb these additional costs.
>
> Activities associated with these changes are not provided for within the base operating expenditure, nor are they due to any changes in real prices, output growth, or productivity.

We accept Evoenergy's submission and consider that a step increase to its forecast base opex would be required over the 2019-24 regulatory control period. This is because the increase in vegetation management requirements reflects a material change in Evoenergy's operating requirements environment, and that an increase in costs in unavoidable.

CCP10 similarly submits that Evoenergy's proposed cost meets the criteria for being regarded as a step change because legislated requirements do constitute new responsibilities for Evoenergy and they are outside the control of the business. However, CCP10 states that the cost impost on ACT energy customers is significant and that it is for Evoenergy to provide evidence that the costs to meet the legislated requirements are efficient. [79]

Is the quantum of the proposed additional costs efficient?

While we accept that the change in legislative obligations will likely materially increase Evoenergy's costs, we must be satisfied that the quantum of the proposed step change reflects the costs an efficient and prudent network service provider would incur under the circumstances. On the basis of the information available to us, we consider that the prudent and efficient level of expenditure required to meet these new responsibilities is less than Evoenergy has put to us.

In evaluating Evoenergy's step-change, we examined the underlying inputs and assumptions behind its cost build up. Throughout our assessment process, we have engaged closely with Evoenergy to understand its proposal and to test its assumptions. This included four information requests and a teleconference with Evoenergy's asset management and regulatory staff.

We have provided Evoenergy with our preliminary assessment of our step-change forecast, which gave Evoenergy an opportunity to comment on our alternative assumptions and conclusions. In response, Evoenergy has provided us with:

- further supporting information

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[78] Evoenergy, *Regulatory Proposal 2019-24, Appendix 6.1 Vegetation and private electrical infrastructure – operating expenditure step change 2019-24 (PUBLIC)*, January 2018, p. 18

[79] Consumer Challenge Panel (Subpanel 10), *CCP10 Response to Evoenergy regulatory proposal 2019–24 and AER issues paper*, May 2018, pp. 13-14.

- revised volume and cost estimates.

We constructed an alternative estimate of $2,404,928 ($2018–19) per annum or $12,024,640 across the 2019–24 regulatory control period. This is 36 per cent lower than Evoenergy's original proposal. In reaching this alternative estimate, we have primarily relied upon the information provided by Evoenergy in its proposal, information requests, and its revised information. Specifically, these are:

- Unit costs based on revealed cost information from Evoenergy's recent urban tree clearance activities.
- Proposed volumes as forecast by Evoenergy (e.g. the number of vegetation encroachments and Evoenergy's reported span length).
- Evoenergy's revised estimates of several smaller cost components.

This differs from Evoenergy's original proposal in two key respects:

- Evoenergy's original proposal relied upon outdated or unrealistic volume forecasts of tree encroachments and power line outages. Evoenergy has since provided more accurate volumes in response to our information requests.
- Evoenergy has constructed its own unit costs based on assumptions about hours per work activity. Where applicable, we have relied upon Evoenergy's actual cost data rather than assumptions when deriving our unit costs.

Evoenergy's step change includes confidential information about the costs of specific activities that make up its total cost forecast. We have examined these costs in confidential Appendix A.

Strathnairn demand management capex/opex trade-off

Our draft decision include Evoenergy's proposed demand management step change in our alternative estimate.

Evoenergy has identified a non-network solution to postpone the need for the construction of a new zone substation at the suburb of Strathnairn. Evoenergy states that it can meet demand in this new urban development with a combination of lower initial capex investment and opex.[80]

Our assessment of this step change is predicated on our assessment of the capex investment Evoenergy proposed to augment supply capacity to the development of Strathnairn. Our assessment shows that there is insufficient existing network capacity to address the forecast load in the Strathnairn area. Based on our review of Evoenergy's business case modelling of the combined capex and opex solution, we are satisfied that the expenditure is prudent and efficient, and have included these expenditures in our alternative forecast. Further details on our capex assessment are set out in Attachment 5.

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[80] Evoenergy, *Regulatory proposal 2019-24, Attachment 6: Operating Expenditure*, January 2018, p. 6-17.

We note both the CCP and the ACT Energy Consumers Policy Consortium have expressed support for the deferral of capex to build zone substations.[81]

6.4.4 Category specific forecasts

We have included a category specific forecast for debt raising costs.

Debt raising costs

We have included debt raising cost of $2.42 million ($2018–19) in our alternative opex forecast. Debt raising costs are transaction costs incurred each time a business raises or refinances debt. Our preferred approach is to forecast debt raising costs using a benchmarking approach rather than a service provider's actual costs in a single year. This provides for consistency with the cost of debt forecasting in the rate of return building block. We discuss this in Attachment 3 of this determination.

6.4.5 Assessment of opex factors under NER

Opex factor	Consideration
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.	There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service provider. The second element, that is, the benchmark operating expenditure that would be incurred by an efficient provider during the forecast period, necessarily provides a different focus. This is because this second element requires us to construct the benchmark opex that would be incurred by a hypothetically efficient provider for that particular network over the relevant period. We have estimated the benchmark opex that an efficient service provider would require over the forecast period and have compared our estimate with Evoenergy's proposal over the relevant regulatory control period. In doing this we relied on approaches set out in our most recent benchmarking report.
The actual and expected operating expenditure of the Distribution Network Service Provider during any proceeding regulatory control periods.	Our forecasting approach uses Evoenergy's revealed actual opex in 2017–18 as the starting point. We have examined Evoenergy's historical expenditure to form a view about whether or not its revealed expenditure is sufficiently efficient to rely on it as the basis for forecasting required opex in the forthcoming period.
The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity	We understand the intention of this particular factor is to require us to have regard to the extent to which service

81 Consumer Challenge Panel (Subpanel 10), *CCP10 Response to Evoenergy regulatory proposal 2019–24 and AER issues paper*, May 2018, pp. 14-15. ACT Energy Consumers Policy Consortium, *AER issues paper on Evoenergy distribution determination 2019 to 2024*, May 2018, p. 3.

Opex factor	Consideration
consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers.[82] Based on the information provided by Evoenergy in its proposal and the CCP's advice, we consider Evoenergy consulted extensively in developing its regulatory proposal. This consultation included an issues paper released in December 2016 and a discussion paper released in July 2017, plus several consumer forums.
The relative prices of capital and operating inputs	We adopted price escalation factors that account for the relative prices of opex and capex inputs. We have also considered capex/opex trade-offs in considering Evoenergy's proposed demand management step change. One reason we will include a step change in our alternative opex forecast is if the service provider proposes a capex/opex trade-off. We consider the relative expense of capex and opex solutions in considering such a trade-off. Evoenergy's proposed one step change as capex/opex trade-offs.
The substitution possibilities between operating and capital expenditure.	As noted above we considered capex/opex trade-offs in considering Evoenergy's demand management step change. We considered the substitution possibilities in considering this step change. In reaching our decision to accept Evoenergy's proposed step change, we noted that this opex was an economical solution that deferred capex from the 2019–24 regulatory control period.
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.	We normally apply the EBSS in conjunction with our revealed cost forecasting approach. Evoenergy did not have an EBSS in place over the 2014–19 regulatory control period. We have reapplied the EBSS for the 2019–24 period.
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.	Some of our techniques assess the total expenditure efficiency of service providers and some assess the total opex efficiency. Given this, we are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of their arrangements with related providers.
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).	This factor is generally only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We did not identify any contingent projects in reaching our draft decision.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	Evoenergy has proposed expenditure for non-network alternatives within its demand management opex step-change proposal.

82 AEMC, Rule Determination, 29 November 2012, pp. 101, 115.

Opex factor	Consideration
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s)	In having regard to this factor, we identify any RIT-D project submitted by the business and ensure the conclusions are appropriately addressed in the total forecast opex. Evoenergy did not submit any RIT-D project for its distribution network.