DRAFT DECISION

Ergon Energy
Distribution Determination
2020 to 2025

Attachment 6
Operating expenditure

October 2019

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to Ergon Energy for the 2020–2025 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following attachments:

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

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Shortened forms

Shortened form	Extended form
ACS	alternative control service
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CCP14	Consumer Challenge Panel, sub-panel 14
CPI	consumer price index
DMIAM	demand management innovation allowance (mechanism)
distributor	distribution network service provider
EBSS	efficiency benefit sharing scheme
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
GSL	guaranteed service levels
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER or the Rules	National Electricity Rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicator
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RIN	regulatory information notice
SCS	standard control services

6 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network services. Forecast opex for standard control 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 Ergon Energy's proposed opex forecast for the 2020–25 regulatory control period.

6.1 Draft decision

Our draft decision is to accept Ergon Energy's opex proposal of $1834.6 million ($2019–20) for the 2020–25 regulatory control period.[1] We are satisfied that it reasonably reflects the opex criteria.[2]

We have tested Ergon Energy's proposal by comparing it to our alternative estimate of total opex of $1964.2 million ($2019–20).[3] Our alternative estimate is $129.5 million (or 7.1 per cent) higher than Ergon Energy's opex proposal.

Table 6.1 sets out Ergon Energy's proposal, our alternative estimate and the differences between them.

Table 6.1 AER's alternative estimate compared to Ergon Energy's proposal ($ million, 2019–20)

	Ergon Energy's proposal	AER alternative estimate	Difference
Based on reported opex in 2018–19	1898.9	1884.9	-14.0
Base adjustment: Negative base adjustments (removal of 'non-recurring' costs)	-127.0	0.0	127.0
Base adjustment: Cost Allocation Method adjustments	78.7	0.0	-78.7
Base adjustment: Service classification change	0.4	1.3	0.9
2018–19 to 2019–20 increment	36.6	36.2	-0.3
Trend: Output growth	56.5	33.2	-23.3
Trend: Price growth	3.5	18.3	14.8
Trend: Productivity growth	-141.4	-28.6	112.7

1 Includes debt-raising costs.

2 NER, cl. 6.5.6(c).

3 Includes debt-raising costs.

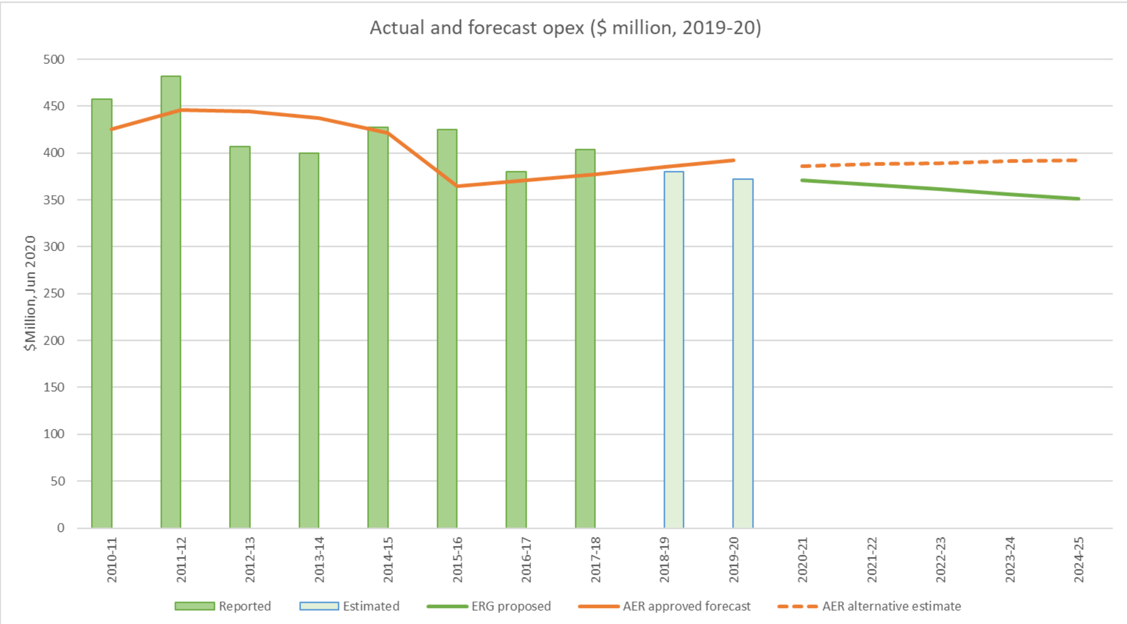
	Ergon Energy's proposal	AER alternative estimate	Difference
Step changes	0.0	0.0	0.0
Total opex (excluding debt raising costs)	1806.1	1945.3	139.1
Debt raising costs	28.5	18.9	-9.6
Total opex (including debt raising costs)	1834.6	1964.2	129.5

Source: AER analysis; Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

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

Figure 6.1 shows actual and allowed opex in the previous and current regulatory periods, as well as Ergon Energy's opex forecast and our alternative estimate in the forthcoming period.

Figure 6.1 Historical and forecast opex ($ million, 2019–20)



Source: AER analysis; Ergon Energy, *Regulatory Accounts 2010–11 to 2017–18*; Ergon Energy, *Economic Benchmarking RIN responses 2010 to 2018,* Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019; Ergon Energy, *Post Tax Revenue Model (PTRM) PTRM Distribution*, January 2019.

Note: Excludes debt raising costs.

We derive our alternative opex forecast by nominating an annual opex expenditure 'base' and then adjusting the opex base over time to account for wage growth, expansion of the network and expected productivity growth.

Typically we use revealed opex as our starting point, and then test the efficiency of this expenditure using benchmarking data. The benchmarking data allows us to compare the performance of networks against their peers. If we find revealed opex is materially inefficient, we adjust the opex base for purposes of our alternative forecast.

Historically, Ergon Energy has performed poorly against our benchmarking metrics. It has had high operating costs compared to other networks, even after accounting for its status as a rural, low density network. Limited reductions in operating expenditure over the first three years of the current regulatory control period (relative to the previous period) have improved Ergon Energy's benchmarking performance only marginally. It is forecasting that it will be able to achieve additional reduction in opex by 2018–19, its proposed base year, which should improve its benchmarking performance further. Ergon Energy also faces unique climate conditions, in particular cyclone activity, and has relatively more sub-transmission assets, which contribute to higher costs. We account for these through our Operating Environment Factors (OEFs).

We have updated our approach to accounting for OEFs in this draft decision by applying the material OEFs identified in our 2018 Annual Benchmarking Report. These OEFs were informed by our recent OEF review and the expert report prepared by Sapere Research Group and Merz Consulting (Sapere-Merz).[4] This is an update to our approach in the April 2015 decisions for Ergon Energy and Energex (and subsequent decisions in November 2018 for NSW distribution businesses and Evoenergy),[5] which applied OEF adjustments that accounted for both material and immaterial OEFs. This update is part of our ongoing benchmarking development work which makes incremental improvements to our benchmarking tools as better information becomes available. The rationale for the update and the method we have followed are explained in more detail below and appendix A of this attachment.

When taking into account the forecast cost reduction in Ergon Energy's base year opex and its unique OEFs, Ergon Energy's benchmarking performance improves to the point where we do not consider its estimated base year opex to be materially inefficient. However, we note that this is a finely balanced assessment. We will review this position after updating our benchmarking analysis, taking into account the actual base year opex included in Ergon Energy's revised proposal and the results of our 2019 Annual Benchmarking Report, which will be published in late November 2019.

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4 In October 2018, we published a report from consultants Sapere Research Group and Merz Consulting (Sapere-Merz) that reviewed material differences in operating environments of distribution businesses in the NEM. The report identified a limited number of OEFs that materially affect the costs of each distribution business. However, Sapere-Merz acknowledged that its analysis was preliminary and could be improved through better data. We intend to consult further with the distribution industry to refine the assessment and quantification of OEFs. See: Sapere Research Group, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, December 2017.

5 AER, *Preliminary Decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 7 Operating Expenditure*, April 2015, pp. 7-261-7-273; AER, *Preliminary Decision, Energex determination 2015–16 to 2019–20, Attachment 7 Operating Expenditure*, April 2015, pp. 7-255-265; AER, *Draft Decision, Ausgrid Distribution determination, 2019-24, Attachment 6 – Operating expenditure*, November 2018, pp. 6-31-6.33; AER, *Draft Decision, Endeavour Energy Distribution determination, 2019-24, Attachment 6 Operating expenditure*, November 2018, pp. 6-27-6.29.

We have also assessed Ergon Energy's proposed base opex adjustments and each component of its trend forecast. While we differ on specific components of Ergon Energy's proposal, our alternative estimate of total opex is higher than Ergon Energy's and we therefore accept its total opex proposal.

While Ergon Energy currently remains a relatively poor performer among distributors in the NEM, it is taking steps to improve the efficiency of its business over the next five years. The improvements should see Ergon Energy's performance converge with the better performers in the NEM. We welcome the proposal as a positive step for consumers.

The key differences between Ergon Energy's proposal and our alternative forecast include:

- Our base year opex, while based on Ergon Energy's proposed base year, is lower than Ergon Energy's as we have applied the most recent RBA's inflation update to inflate 2018–19 nominal dollars to June 2019–20 dollars.[6]
- Our alternative estimate does not include the removal of the negative base adjustments from base opex as proposed by Ergon Energy. This is because information provided by Ergon Energy shows that while it is not seeking to recover these costs from consumers, it has incurred these costs in the base year and will continue to incur them at some level over the forecast period.[7] Our standard approach is to set opex based on a revealed cost approach of actual costs incurred.
- Our alternative estimate does not include the additional costs proposed by Ergon Energy to account for the cost allocation method (CAM) changes. Ergon Energy has not been able to adequately explain and justify this proposed increase in opex. We have set out what information we would require should Ergon Energy wish to propose similar adjustments in its revised proposal.
- We have applied a lower forecast output growth rate compared to that proposed by Ergon Energy. Our estimate of output growth uses Ergon Energy’s forecasts of growth in customer numbers, circuit line length, maximum demand and energy throughput from its regulatory determination RIN response rather than its opex model. We believe the regulatory determination Regulatory Information Notice (RIN) numbers, which are more recent, reflect Ergon Energy’s best available forecast output growth.
- We have used a higher forecast input price growth rate compared to that proposed by Ergon Energy. We have forecast labour price growth using the Deloitte Access Economics (Deloitte) forecasts prepared for the AER. This is a change in the

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6 RBA, *Statement on Monetary Policy – August 2019*, August 2019, Forecast Table – August 2019, available at https://www.rba.gov.au/publications/smp/2019/aug/pdf/forecast-table-2019-08.pdf.

7 Ergon Energy, *Information request 51 – Q18 and Q21*, 21 June 2019, p.11; Ergon Energy, *Information request 56 – Q10, Q12 and Q13*, 17 July 2019, pp. 5-6.

approach adopted in our previous determinations of averaging the forecasts from Deloitte and the consultant (generally BIS Oxford Economics). It reflects analysis that from 2007 to 2018 Deloitte's real Wage Price Index (WPI) growth forecasts have been more accurate. We have not included Ergon Energy's 0.6 per cent average annual unit rate efficiency discount in our input price growth forecast.

- We have applied our 0.5 per cent per year productivity growth forecast from our opex productivity growth review final decision.[8] This is lower than Ergon Energy's 2.58 per cent average annual productivity growth forecast and is in line with our standard practice of applying a sector-wide productivity forecast that reflects improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations.

6.2 Ergon Energy's proposal

Ergon Energy proposed total forecast opex of $1834.6 million ($2019–20) for the 2020–25 regulatory control period (see Table 6.2).[9] This is 6.3 per cent lower than Ergon Energy's actual and estimated opex for the 2015–20 regulatory control period.[10]

Table 6.2 Ergon Energy's proposed opex ($ million, 2019–20)

	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Opex excluding category specific forecasts	371.2	365.9	361.3	356.3	351.4	1806.1
Debt raising costs	5.6	5.7	5.7	5.8	5.8	28.5
Total opex	376.8	371.6	367.0	362.1	357.2	**1834.6**

Source: Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

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

Ergon Energy stated that it adopted our base–step–trend approach to forecast opex for the 2020–25 regulatory control period.[11] In Figure 6.2 we separate Ergon Energy's opex proposal into the different elements that make up its forecast.

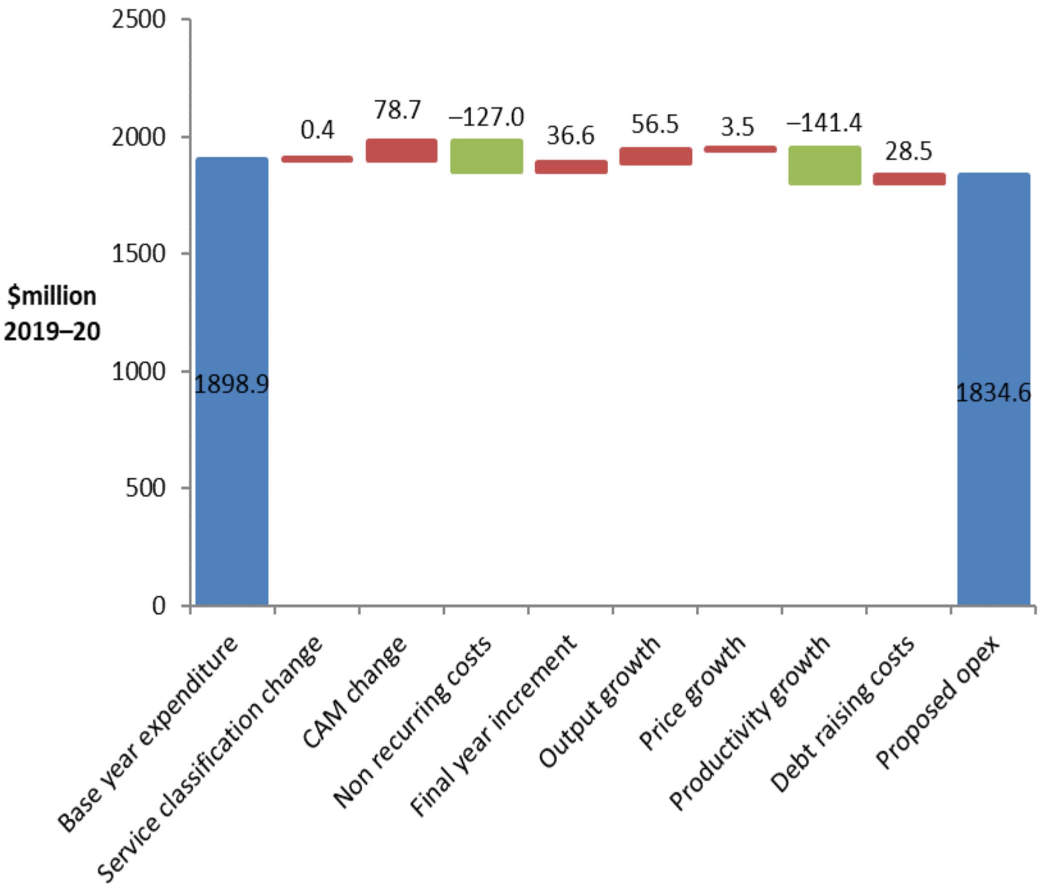
8 AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019.

9 Including debt raising costs. Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

10 Including debt raising costs, not including solar feed-in tariffs, AER analysis.

11 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 40.

Figure 6.2 Ergon Energy's opex forecast ($ million, 2019–20)



Source: AER analysis; Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

The key elements of Ergon Energy's proposal are:

- Ergon Energy used estimated opex in 2018–19 as the base to forecast its total opex proposal resulting in $1898.9 million ($2019–20) in base opex over the 2020–25 regulatory control period.[12]
- Ergon Energy proposed adjustments to its base year opex, which reduce its opex forecast by a net $47.9 million ($2019–20). These comprise:
  - an adjustment to reflect changes to its CAM, which increases its opex forecast by $78.7 million ($2019–20)[13]
  - an adjustment for service classification changes, which increases its opex forecast by $0.4 million ($2019–20)[14]

12 AER analysis; Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25,* January 2019, p. 46.

13 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25,* January 2019, p.46; AER analysis.

14 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25,* January 2019, p.46; AER analysis.

- negative base adjustments that remove 'non-recurring' costs including reform costs incurred to improve Ergon Energy's efficiency and post-merger savings expected to be realised in 2019–20. These negative base adjustments reduce Ergon Energy's opex forecast by $127.0 million ($2019–20).[15] We refer to these 'non-recurring' costs as negative base adjustments in this attachment.

- Ergon Energy applied the approach in the *Expenditure Forecast Assessment Guideline* (the Expenditure Assessment Guideline) to calculate the 2018–19 to 2019–20 increment (the starting point for its forecast).[16] This increases its opex forecast by $36.6 million ($2019–20).[17]
- Ergon Energy applied its forecast of the overall rate of change to its estimate of opex for 2018–19, consistent with the Expenditure Assessment Guideline.[18] Output growth and real price growth increase the opex forecast by $56.5 million and $3.5 million respectively, while productivity growth reduces the opex forecast by $141.4 million ($2019–20).[19] This reduces Ergon Energy's opex forecast by an overall $81.4 million ($2019–20).

Ergon Energy did not propose any step changes for the 2020–25 regulatory period.[20]

Ergon Energy proposed a category specific forecast for debt raising costs, which increased its opex forecast by $28.5 million ($2019–20).[21]

Overall, Ergon Energy's proposal results in a total opex forecast of $1834.6 million ($2019–20).[22]

6.2.1 Stakeholder views

We received six submissions on Ergon Energy's opex proposal, including from the AER's Consumer Challenge Panel (CCP14), the Queensland Council of Social Services (QCOSS), National Seniors Australia, Origin Energy, the Energy Consumers Australia (ECA) and the Queensland Government's Electrical Safety Office. We note the ECA included a report by Dynamic Analysis to supplement the ECA's submission. A summary of these submissions is provided in Table 6.3.

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15 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*. January 2019, pp. 46-47; AER analysis.

16 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 22–23.

17 Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019; AER analysis.

18 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 22–23; Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

19 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25,* January 2019, pp. 50–51; AER analysis.

20 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25,* January 2019, p. 40.

21 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25,* January 2019, p. 52.

22 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25,* January 2019, p. 40; Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

We refer to submissions that relate to specific components of Ergon Energy's opex forecast in section 6.4, where we explain the reasoning for our draft decision.

Table 6.3 Submissions on Ergon Energy's opex proposal

Stakeholder	Issue	Description
CCP14, QCOSS, ECA/Dynamic Analysis, National Seniors	Choice of base year and assessment of efficient base opex	QCOSS stated Ergon Energy's benchmarking results indicate Ergon Energy's base opex may be relatively inefficient.[23] CCP14 also identified Ergon Energy's base opex assessment as an area of key concern where the best interests of customers may not be evident.[24] The ECA also questioned whether Ergon Energy's performance in the mid-range of the AER's opex benchmarks is justified, and whether customers should expect the [Energy Queensland] networks to achieve deeper efficiencies.[25] The ECA and the consultants Dynamic Analysis were not convinced that Energy Queensland's environmental and operating context justified higher costs relatively to its peers.[26] Dynamic Analysis argued it is up to the networks to quantitatively demonstrate how their operating and environmental factor leads to higher costs structures.[27] Dynamic Analysis also noted there is no evidence of what the negative base adjustments specifically relate to, but recognised Energy Queensland's efforts to "do the right thing" by excluding non-recurrent costs.[28] National Seniors Australia also argued Ergon Energy, as part of Energy Queensland, is not pursuing opportunities with Energex to share costs to reduce operating costs.[29]
CCP14, ECA/Dynamic Analysis	Productivity growth	Whilst CCP14 welcomed Ergon Energy offering additional productivity growth, they raised concerns about the reliance on ICT expenditure to underpin this productivity growth.[30] They argued it would be beneficial to see a clearer linkage between ICT investment and productivity improvement.[31] They also noted the 2.58 per cent per year productivity improvement figures proposed by Ergon Energy has not been derived clearly or in detail.[32]

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23 Queensland Council of Social Services, *QLD electricity distribution determinations – Energex and Ergon 2020 to 2025, QCOSS Submission: AER Issues Paper*, May 2019, p. 8.

24 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020-25 Regulatory Proposals*, May 2019, p. 5.

25 Energy Consumers Australia, *AER Issues Paper: QLD electricity distribution determinations Energex and Ergon Energy 2020 to 2025 Submission*, June 2019, p. 15.

26 Energy Consumers Australia, *AER Issues Paper: QLD electricity distribution determinations Energex and Ergon Energy 2020 to 2025 Submission*, June 2019, p.15; Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020-25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 6.

27 Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020-25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 27.

28 Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020-25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 32.

29 National Seniors Australia, *Response to AER Issues Paper: Qld electricity distribution determinations, Energex and Ergon Energy, 2020 to 2025,* May 2019, p. 4.

30 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020-25 Regulatory Proposals*, May 2019, p. 8.

31 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020-25 Regulatory Proposals*, May 2019, p. 13.

32 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020-25 Regulatory Proposals*, May 2019, p. 13.

Stakeholder	Issue	Description
		Dynamic Analysis noted Ergon Energy should be commended for embedding the savings from their new digital strategy into its opex forecasts.[33]
Origin Energy, ECA/Dynamic Analysis	Output growth / labour price growth	Origin Energy encouraged us to test Ergon Energy's price and output growth forecasts.[34] Dynamic Analysis noted that while forecast growth in energy volumes and customer numbers is higher than actuals in the 2015–20 period, the overall output growth forecast appears reasonable.[35]
CCP14	Step changes	CCP14 was pleased to observe the absence of step changes.[36]
Queensland Government Electrical Safety Office	Bushfire risk and vegetation management	The Electrical Safety Office noted that Ergon Energy's proposal did not include enough detail on these areas to make an informed comment.[37]

6.3 Assessment approach

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.[38] 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 cap regulation (where an opex allowance is granted over a multi-year regulatory control period) and the efficiency benefit sharing scheme (EBSS).

The approach we apply to assessing a business's opex (and which we have applied in this draft decision) is more fully described in our Expenditure Forecast Assessment Guideline for Electricity Distribution,[39] and its accompanying explanatory materials.

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us, the regulator.[40] Incentive regulation encourages regulated businesses to reduce costs below the regulator's

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33 Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020-25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 48.

34 Origin Energy, *Letter to Mr Sebastian Roberts RE: QLD Regulatory Proposal 2020-25*, May 2019, p. 2.

35 Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020-25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 34.

36 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020-25 Regulatory Proposals*, May 2019, p. 13.

37 Queensland Government Electrical Safety Office, *Feedback on Energex and Ergon Energy Regulatory Submissions 2020-15*, p. 4.

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

39 AER, *Explanatory Statement*, *Expenditure Forecast Assessment Guideline,* November 2013.

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

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.

Our general approach is to assess the efficiency of 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 forecasting methods as set out in our Expenditure Assessment Guideline, known as the 'base–step–trend' approach (section 6.3.2). This is generally a 'top-down' approach, but there may be circumstances where we need to use bottom-up analysis, particularly in relation to our base opex assessment and for step changes.[41]

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.[42] We may make a downward adjustment to the business's revealed opex if we consider it is operating in a materially inefficient manner. Material inefficiency is a concept we introduce in our Guideline.[43] We consider a service provider is materially inefficient when it is not at or close to its peers on the efficiency frontier. We define this more precisely in the context of economic benchmarking below.

Incentive regulation is designed to leave day-to-day decisions to the network businesses.[44] It allows the network businesses the flexibility to manage their assets and labour as they see fit to achieve the opex objectives in the National Energy Rules (NER),[45] and more broadly, the National Electricity Objective (NEO).[46] 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.[47]

The Australian Energy Market Commission (AEMC) supports this view of our role as the economic regulator. It stated: [48]

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41 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'.

42 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 32.

43 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 22.

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

45 NER, cl. 6.5.6(a).

46 NEL, s. 7.

47 NER, cl. 6.5.6(c).

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

> 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…

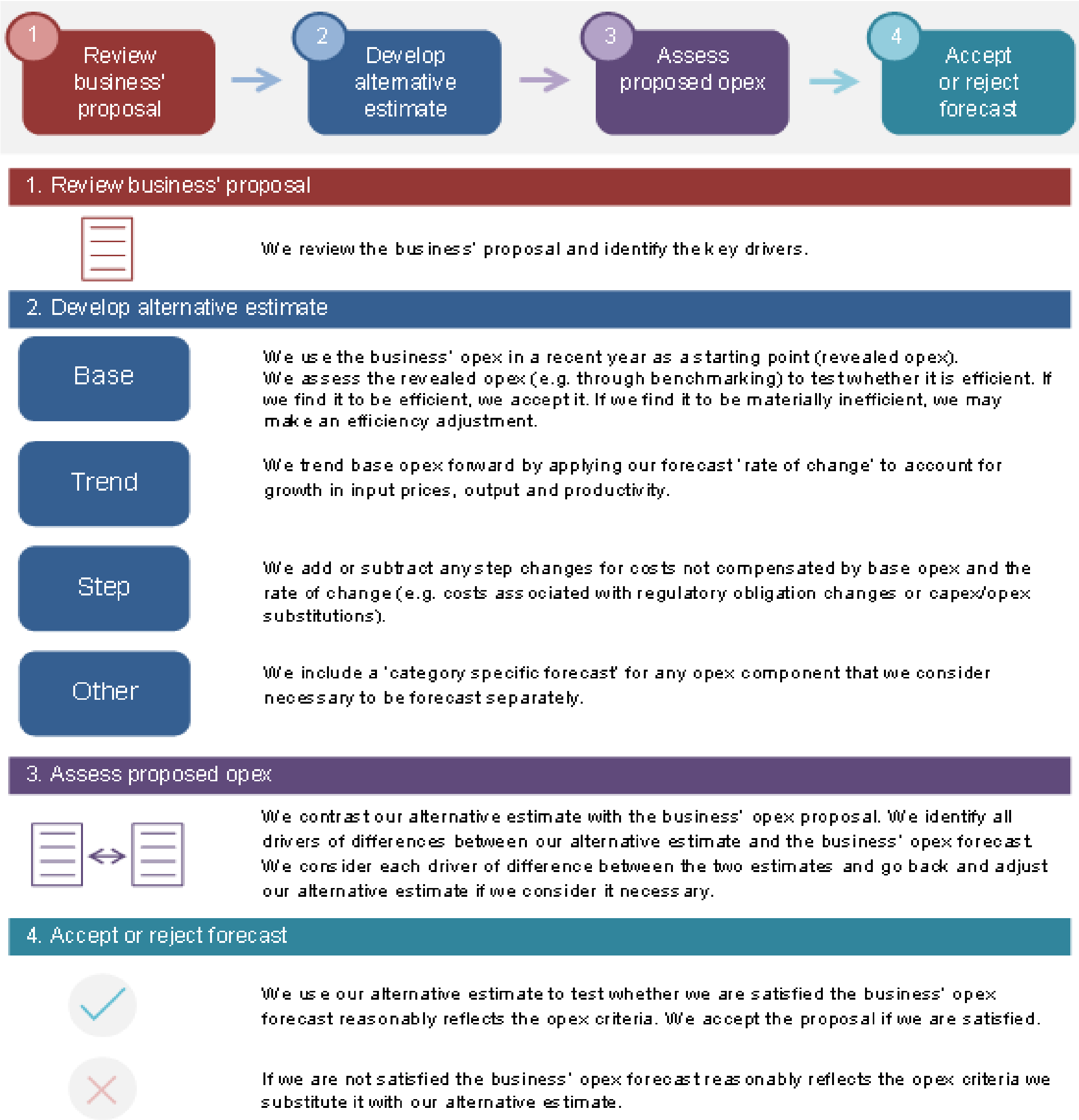
6.3.2 Base–step–trend forecasting approach

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. We also have regard to the opex factors set out in the NER in making this assessment.[49] Where a 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.[33]

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

[49] The opex factors are set out in NER, cl. 6.5.6(e).

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 must have regard to the opex factors in deciding whether we are satisfied that the business's proposed opex forecast reasonably reflects the opex criteria.[50]

[50] NER, cl. 6.5.6(e)(5).

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[51] 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 relevant sources of opex growth.

We forecast input price growth using a combination of labour and non-labour price change forecasts. Labour costs represent a significant proportion of a distribution business's costs.[52] 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.

We forecast output growth to account for the annual increase in output of services. The output measures used should, ideally, be the same measures used to forecast

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[51] Our benchmarking report is one of the opex factors we must consider in determining whether to accept a business opex proposal: NER, cl.6.5.6(e)(4); AER, *Annual benchmarking report—Electricity distribution network service providers*, November 2018 and the Economic Insights *Annual Benchmarking Report Data Update, 8* October 2019 is our most recent benchmarking report.

[52] AER, *Explanatory Statement*, *Expenditure Forecast Assessment Guideline,* November 2013, p. 49.

productivity growth.[53] Productivity measures the change in output for a given amount of input.

The output measures we typically use for distribution businesses are energy delivered, ratcheted maximum demand, customer numbers and circuit length.[54] 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 opex productivity growth captures the sector-wide, forward looking, improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations. We generally base our estimate of productivity growth on recent productivity trends across the electricity 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 and may rely on other industry or economy wide indicators.

We recently reviewed our approach to forecasting opex productivity growth and determined that a forecast of 0.5 per cent per year reflects a reasonable forecast of the productivity growth a prudent and efficient electricity distributor can make.[55] We stated our intention to adopt this opex productivity growth forecast when we review the opex forecasts proposed by electricity distributors going forward.[56]

Step changes and category-specific forecasts

Lastly, we add or subtract any components of opex that are not appropriately 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.[57] These adjustments are in the form of 'step changes' or 'category-specific forecasts'.

Step changes

Step changes should not double count costs included in other elements of the total opex forecast. As explained in the Expenditure Assessment 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.[58] 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

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53 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 23.

54 These measures are discussed more fully in our benchmarking reports, see AER, *Annual Benchmarking Report – Electricity distribution network service* providers, November 2018, pp. 46–52.

55 AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019, pp. 8–11.

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

57 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 24.

58 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 24.

resulting from changed obligations.'[59] 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.[60]

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.[61] Our starting position is that only circumstances that would change a business's fundamental opex requirements warrant the inclusion of a step change in the opex forecast.[62] Two typical examples are:

- a material change in the business's regulatory obligations
- an efficient and prudent capex/opex substitution opportunity.[63]

We may accept a step change if a material 'step up' or 'step down' in expenditure is required by a network business to comply prudently and efficiently with a new, binding regulatory obligation that is not reflected in the productivity growth forecast.[64] 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 to continue incurring such costs associated with the new regulatory obligation into future regulatory control 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

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59 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 52.

60 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 24.

61 NER, cl. 6.5.6(a).

62 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

63 One of the opex factors we must have regard to in assessing expenditure proposals is substitution possibilities between opex and capex: NER, cl.6.5.6(e)(7).

64 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 11.

to meet the change in regulatory obligations.[65] We stated in the explanatory statement accompanying the Expenditure Assessment Guideline:[66]

> [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 improperly benefit from a higher opex forecast and the efficiency gains.[67]

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 (or "repex").[68] The business should provide robust cost–benefit analysis to clearly demonstrate how increased opex would be more than offset by capex savings.[69]

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 control periods.

65 AER, *Explanatory Statement*, *Expenditure Forecast Assessment Guideline,* November 2013, p. 11 and pp. 51–52.

66 AER, *Explanatory Statement*, *Expenditure Forecast Assessment Guideline,* November 2013, p. 52.

67 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 11.

68 AER, *Explanatory Statement*, *Expenditure Forecast Assessment Guideline,* November 2013*,* p. 74.

69 AER, *Explanatory Statement*, *Expenditure Forecast Assessment Guideline,* 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.

A category specific forecast is an amount we may allow to be included in the opex forecast for a particular year, which is not appropriate as a step change, nor for inclusion in base opex, but which we nevertheless consider meets the legal criteria for efficient expenditure in that year.

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 and the demand management incentive allowance mechanism (DMIAM). In jurisdictions where guaranteed service levels (GSL) payments were historically included under category specific forecasts, we continue to do so. 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 DMIAM, 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. This is a reasonable assumption given that the business has operated in the past with that level of opex, demonstrating that it is able to operate prudently and efficiently in meeting all its existing regulatory obligations, including its safety and reliability standards. We consider it is also reasonable to expect the same outcome looking forward with the increase provided through the trend growth in the base opex. 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 it does not have the same incentive to identify declining costs in its forecasts. 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 Ergon Energy's total forecast opex we also took into account other components of its revenue proposal that could interrelate with our opex decision.[70] The matters we considered in this regard included:

- the EBSS carryover—the level of opex used as the starting point to forecast opex (the final year of the current period) should be the same as the level of opex used to calculate the EBSS carryover amounts. This consistency ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years
- the operation of the EBSS in the 2015–20 regulatory control period, which provided Ergon Energy an incentive to reduce opex in the base year
- 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 price growth used to estimate the rate of change in opex
- 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
- interactions and trade-offs between the opex and capex proposals.

6.4 Reasons for draft decision

Our draft decision is to accept Ergon Energy's opex proposal of $1834.6 million (2019–20) for the 2020–25 regulatory control period.[71] We are satisfied that it reasonably reflects the opex criteria.[72]

Our alternative estimate is $1964.2 million ($2019–20),[73] which is $129.5 million (or 7.1 per cent) higher than Ergon Energy's opex proposal.

This section outlines the key inputs and assumptions we made in developing our alternative estimate of efficient costs over the 2020–25 regulatory control period.

Table 6.4 illustrates the differences between our alternative estimate of forecast opex and Ergon Energy's proposal.

70 When making revenue decisions under the NEL, we must specify the manner in which the constituent components of our decision relate to each other, and the manner in which we take account of these interrelationships: NEL, s. 16(1)(c).

71 Includes debt-raising costs.

72 NER, cl. 6.5.6(c).

73 Includes debt-raising costs.

Table 6.4 AER's alternative estimate compared to Ergon Energy's proposal ($ million, 2019–20)

	Ergon Energy's proposal	AER alternative estimate	Difference
Based on reported opex in 2018–19	1898.9	1884.9	-14.0
Base adjustment: Negative base adjustments (removal of non-recurring costs)	-127.0	0.0	127.0
Base adjustment: Cost Allocation Method adjustments	78.7	0.0	-78.7
Base adjustment: Service classification change	0.4	1.3	0.9
2018–19 to 2019–20 increment	36.6	36.2	-0.3
Trend: Output growth	56.5	33.2	-23.3
Trend: Price growth	3.5	18.3	14.8
Trend: Productivity growth	-141.4	-28.6	112.7
Step changes	0.0	0.0	0.0
Total opex (excluding debt raising costs)	1806.1	1945.3	139.1
Debt raising costs	28.5	18.9	-9.6
Total opex (including debt raising costs)	1834.6	1964.2	129.5

Source: AER analysis; Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

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

We have used Ergon Energy's proposed base year opex of $379.8 million (2018–19 estimated opex in $2019–20) as the basis for our alternative estimate of base opex.[74] Our assessment of revealed cost data and a range of benchmarking techniques shows that historically, Ergon Energy has performed poorly against our benchmarking metrics. It has had high operating costs compared to other networks, even after accounting for its status as a rural, low density network. Ergon Energy has achieved some limited reductions in operating expenditure over the first three years of the current period (relative to the previous period) and is forecasting to achieve a further reduction in 2018–19, its proposed base year. Ergon Energy also faces unique climate conditions, in particular cyclone activity, and has relatively more sub-transmission assets, which contribute to higher costs. We account for these through our Operating Environment Factors (OEFs).

[74] Ergon Energy, *1.004 – Ergon Energy Regulatory Proposal 2020–25*, January 2019, p. 46. Our estimate of base opex differs to Ergon Energy's proposed amount due to updated inflation figures. We will update Ergon Energy's base year expenditure with actual 2018–19 opex for the final decision

We have updated our approach to accounting for OEFs in this draft decision by applying the material OEFs identified in our 2018 Annual Benchmarking Report. These OEFs were informed by our recent OEF review and the expert report prepared by Sapere-Merz.[75] This is an update to our approach in the April 2015 decisions for Ergon Energy and Energex (and subsequent decisions in November 2018 for NSW distribution businesses and Evoenergy),[76] which applied OEF adjustments that accounted for both material and immaterial OEFs. This update is part of our ongoing benchmarking development work which makes incremental improvements to our benchmarking tools as better information becomes available. The rationale for the update and the method we have followed are explained in more detail below and appendix A of this attachment.

When taking into account this forecast cost reduction in its base year opex and its unique OEFs, Ergon Energy's benchmarking performance improves to the point where we do not consider its estimated base year opex to be materially inefficient.

However, we note that Ergon Energy currently remains a relatively poor performer among distributors in the NEM and that our position on the efficiency of its base year opex is a finely balanced assessment. We will review this position after updating our benchmarking analysis, taking into account the actual base year opex included in Ergon Energy's revised proposal and the results of our 2019 Annual Benchmarking Report.

While we consider there is sufficient evidence to indicate that Ergon Energy has been relatively inefficient over time, we find that its opex efficiency has improved such that its estimated base year opex likely reflects a level of opex that is not materially inefficient. We note that this is a finely balanced determination as Ergon Energy's base opex is on the border between efficiency and material inefficiency. We will review this position and update our benchmarking analysis for our final decision, taking into account the actual opex in 2018–19 included in Ergon Energy's revised proposal.

The main drivers of differences between Ergon Energy's proposal and our alternative estimate of total opex are:

[75] In October 2018, we published a report from consultants Sapere Research Group and Merz Consulting (Sapere-Merz) that reviewed material differences in operating environments of distribution businesses in the NEM. The report identified a limited number of OEFs that materially affect the costs of each distribution business. However, Sapere-Merz acknowledged that its analysis was preliminary and could be improved through better data. We intend to consult further with the distribution industry to refine the assessment and quantification of OEFs. See: Sapere Research Group, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, December 2017.

[76] AER, *Preliminary Decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 7 Operating Expenditure*, April 2015, pp. 7-261-7-273; AER, *Preliminary Decision, Energex determination 2015–16 to 2019–20, Attachment 7 Operating Expenditure*, April 2015, pp. 7-255-265; AER, *Draft Decision, Ausgrid Distribution determination, 2019-24, Attachment 6 – Operating expenditure*, November 2018, pp. 6-31-6.33; AER, *Draft Decision, Endeavour Energy Distribution determination, 2019-24, Attachment 6 Operating expenditure*, November 2018, pp. 6-27-6.29.

- Our alternative base year opex, while based on Ergon Energy's proposed base year, is lower than Ergon Energy's number as we have applied the most recently available RBA's inflation data to inflate Ergon Energy's base opex to 2019–20 dollars.[77]
- Our alternative estimate does not include the removal of the negative base adjustments (non-recurring costs) from base opex as proposed by Ergon Energy. Our standard approach is to set opex based on a revealed cost approach of actual costs incurred. Information provided by Ergon Energy indicates that while it is not seeking to recover these costs from consumers, it has incurred these costs in the base year and will continue to incur them at some level over the forecast period.[78] This treatment of Ergon Energy's negative base adjustments in our alternative opex estimate has implications for Ergon Energy's EBSS carry over amount (see Attachment 8).
- Our alternative estimate does not include the additional costs proposed by Ergon Energy that have resulted from changes CAM. Ergon Energy has not been able to adequately explain and justify this proposed increase in opex. We have set out what information we would require should Ergon Energy wish to propose similar adjustments in its revised proposal.
- We have used a higher forecast input price growth rate compared to that proposed by Ergon Energy. In a change to the approach adopted in our previous determinations, we have forecast labour price growth using the Deloitte forecasts prepared for the AER. This change reflects our judgment that over the period 2007 to 2018 Deloitte's real WPI growth forecasts have been more accurate than forecasts we have used previously. In addition, in line with our practice of using an industry-wide approach to forecasting input price growth, we have not included Ergon Energy's proposed 0.6 per cent average annual unit rate efficiency discount to our input price growth forecast.
- We have applied a lower forecast output growth rate compared to that proposed by Ergon Energy. Our estimate of output growth uses Ergon Energy's forecasts of growth in customer numbers, circuit line length, maximum demand and energy throughput from its regulatory determination RIN response rather than its opex model. We believe the regulatory determination RIN numbers, which are more recent, reflect Ergon Energy's best available output growth forecast.
- We have applied our sector-wide 0.5 per cent per year productivity growth forecast from our opex productivity growth review final decision.[79] This is in line with our standard practice of applying a sector-wide productivity forecast that reflects

[77] RBA, *Statement on Monetary Policy – August 2019*, August 2019, Forecast Table – August 2019, available at https://www.rba.gov.au/publications/smp/2019/aug/pdf/forecast-table-2019-08.pdf.

[78] Ergon Energy, *Information request 51 – Q18 and Q21*, 21 June 2019, p.11; Ergon Energy, *Information request 56 – Q10, Q12 and Q13*, 17 July 2019, pp. 5-6.

[79] AER, Final decision paper, *Forecasting productivity growth for electricity distributors*, March 2019.

improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations.

We discuss the components of our alternative estimate below in more detail. Full details of our alternative estimate are set out in our opex model, which is available on our website.[80]

6.4.1 Base opex

We have relied on Ergon Energy's estimated opex in 2018–19 to calculate our alternative estimate for the 2020–25 regulatory control period, as proposed by Ergon Energy.[81] This is because, while our revealed cost and benchmarking analysis indicates that Ergon Energy has been historically inefficient, we do not consider its estimated base year opex to be materially inefficient after taking into account the reduction in costs it is forecasting to achieve in 2018–19 and its unique OEFs. However, as noted above, Ergon Energy currently remains a relatively poor performer among distributors in the NEM and our position on the efficiency of its base year opex is a finely balanced assessment as Ergon Energy's base opex is on the borderline of material inefficiency. We will review this position and update our benchmarking analysis for our final decision, taking into account the actual opex in 2018–19 included in Ergon Energy's revised proposal and the results of our 2019 Annual Benchmarking Report.

This section outlines our analysis of the prudent and efficient level of base opex that Ergon Energy would need to maintain the safe and reliable provision of electricity services over the 2020–25 regulatory control period.[82] It also assesses the various positive and negative adjustments to base opex proposed by Ergon Energy.

Efficiency of base opex

Ergon Energy submitted that 2018–19 is the most suitable year for its base year because it is the most recent year for which audited data will be available, and because the level of opex in 2018–19 will be more reflective of ongoing requirements than other recent years.[83] Ergon Energy notes that 2018–19 is the first year that its costs will largely reflect the new business structure adopted following the establishment of Energy Queensland and will more fully reflect the ongoing efficiency savings it has been able to achieve under the changes.[84]

Figure 6.4 shows Ergon Energy's actual and forecast opex and our regulatory decisions over the previous, current and next regulatory control periods. Ergon Energy

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80 AER, *Draft Decision, Ergon Energy Distribution Determination, 2020 to 2024, Opex model*, October 2019.

81 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 46; Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

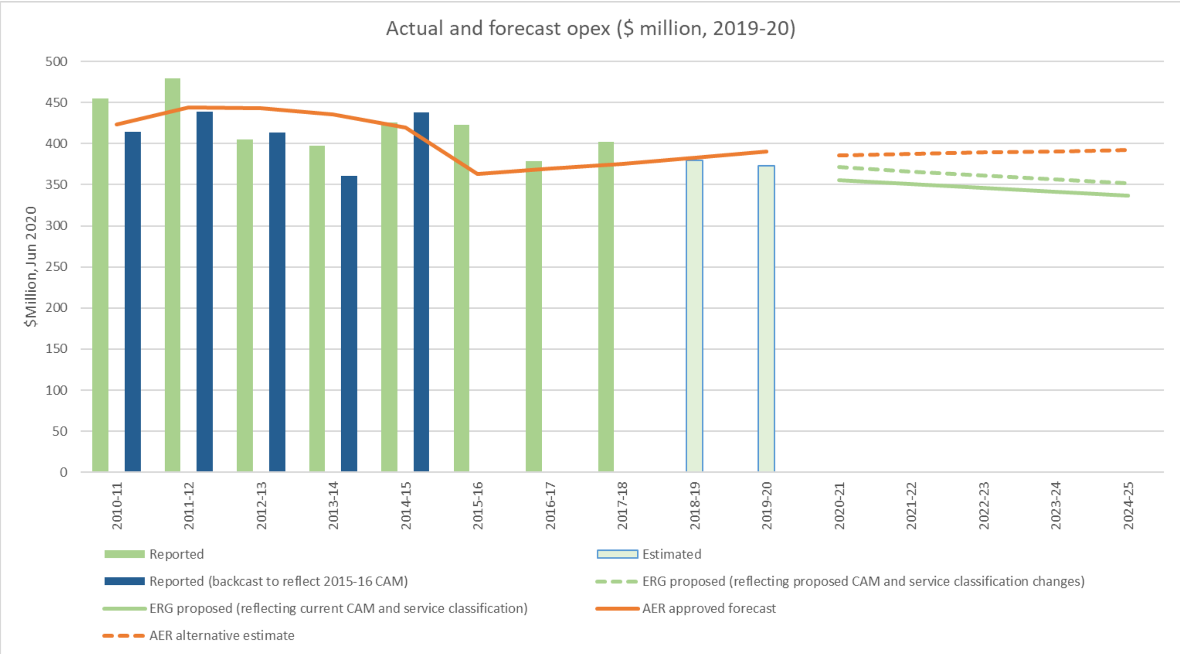
82 NER, cl. 6.5.6(e)(5).

83 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 46.

84 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 46.

changed its CAM in 2015–16, the first year of the current regulatory control period. To allow a like-for-like comparison across the previous and current regulatory control periods, Ergon Energy's actual opex over the 2010–15 regulatory period is shown under both the CAM that applied for that period (the green columns) and backcast using the current CAM that came into place in 2015–16 (the blue columns).[85] Ergon Energy also has a new CAM that will take effect from 1 July 2020 and this is shown in Ergon Energy's proposed opex in the green dash line for the 2020–25 regulatory control period.

Figure 6.3 Ergon Energy's historic and forecast opex ($ million, 2019–20)



Source: AER analysis; Ergon Energy, *Economic Benchmarking RINs*; Ergon Energy, *Economic Benchmarking RINs (recast)*; Ergon Energy, *6.008 - Opex forecast - SCS,* January 2019; Ergon Energy, *17.053 - 2020-25 Regulatory Determination RIN template*, January 2019.

Note: Reported opex for a given year is based on the CAM which applied in that year, and is calculated by total SCS opex (EB RINs) - debt-raising costs (EB RINs) - feed-in tariffs (AER database for FY11–15 and the EB RINs for FY16–17).

Figure 6.4 shows that while Ergon Energy's revealed costs (on a current CAM basis) have followed a marginally decreasing trend from 2010–11 to 2017–18, its most recent three years of opex likely continues to include inefficiencies. Ergon Energy's average annual opex has decreased from $413.1 million per year ($2019–20) over the 2010–15 regulatory control period to $401.0 million per year ($2019–20) over the first three years of the current regulatory control period (2015–16 to 2017–18). However, Figure 6.4 also shows that over the first three years of the current regulatory period, Ergon

[85] Ergon Energy has a new CAM change approved to take effect from 1 July 2020.

Energy's operating costs have remained above the level of efficient and prudent opex set in our October 2015 final decision. Ergon Energy's opex increased from $378.5 million ($2019–20) in 2016–17 to $401.8 million ($2019–20) in 2017–18 (the most recent years for which we have actuals) to be $26.4 million or 7.0 per cent above our October 2015 final decision allowance.[86]

Ergon Energy forecasts that its opex will decrease by approximately 5.5 per cent to $379.8 million ($2019–20) in 2018–19, its proposed base year. This represents a level of opex that is consistent with our October 2015 final decision view on the level of costs an efficient and prudent operator in Ergon Energy's circumstances would need to provide safe and reliable network services.[87]

A review of the main categories of Ergon Energy's opex shows that this estimated decrease in opex between 2017–18 and 2018–19 is to be achieved primarily through reductions in:

- Total overheads (particularly non-network and corporate overheads), which are projected to decline from $213.8 million ($2019–20) to $204.5 million ($2019–20) 2019–20
- Emergency response costs, which are projected to decline from $57.8 million ($2019–20) to $50.9 million ($2019–20)2019–20.[88]

In its initial proposal, Ergon Energy states that since 2015–16 it has been implementing various efficiency measures to reduce costs across its business, including opex:

> 'In the 2015–16 Mid-Year Fiscal and Economic Review, the Queensland Government announced our merger with Energex under the banner of Energy Queensland. The merger was accompanied by a clear intent to achieve cost reductions and efficiencies in opex and capex (totex) in the two regulated network businesses to the benefit of customers. The merger took effect from 1 July 2016.
>
> Notwithstanding the reductions already targeted for the two businesses in their 2015-20 Regulatory Proposals and the AER's associated Distribution Determinations, in order to improve further on the baseline, an additional totex target of $562 million net of implementation costs in nominal terms over four years (2016–17 to 2019–20) was formalised for the two business. These further targeted savings were against the forward estimates at that time, which approximated the regulatory expenditure allowance over the period to 2019–20.' ….

86 AER, *Final Decision Ergon Energy distribution determination - Attachment 7 - operating expenditure* - October 2015, p.7-7; AER analysis.

87 AER, *Final Decision Ergon Energy distribution determination - Attachment 7 - operating expenditure*, October 2015, p.7-7; AER analysis.

88 AER analysis; Ergon Energy*, Category Analysis RINs*; Ergon Energy, *17.053 - 2020-25 Regulatory Determination RIN template*, January 2019.

The combined entity has been successful in achieving the savings' target through a combination of approaches, including:

- scale benefits
- re-negotiations with suppliers
- selection of, and adoption of, best practice across the two entities
- reconsideration of work practices and scheduling, and
- a general re-examination of planned spend to ensure it is prudent and efficient.[89]

Ergon Energy further notes that is has been able to achieve opex efficiencies over the current period through:

- 'Savings from our merger with Energex, discussed above
- Introduction of new rapid inspection technologies for overhead and ground plant to cover the complete network which reduces "traditional" inspection techniques, needs and costs. Examples include:
- Thermal imaging of low voltage pillars
- LIDAR analysis of overhead conductors
- Reduction in the program units of aerial inspections through better use of data to target specific assets and environmental conditions
- Collaborative engagement with councils on removal of inappropriate trees, and
- Alignment of condition assessments, delivery timeframes and process improvements in inspection and defect management areas.'[90]

In responses to our information requests, Ergon Energy has provided data on some of the 'reform' costs associated with the merger with Energex that it has incurred, and will continue to incur, over the current regulatory control period to improve the efficiency of its business (Table 6.5). These include:

- Operational improvements, which it identifies as primarily restructuring and redundancy payments
- Non-recurring costs, which it identifies as change initiatives that are incremental to ordinary business operations and that include functional review and larger organisational wide projects that target the review, redesign and implementation of improvements to its business practices.[91]

89 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 21-22.

90 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 23.

91 Ergon Energy, *Information request 37 – Q1 and Q2*, 11 June 2019, p. 3; Ergon Energy, *Information request 56 – Q10*, 17 July 2019, pp. 14-15.

Table 6.5 shows that reform costs peaked at $49.7 million ($2019–20) in 2015–16, decreased in 2016–17 and 2017–18 and are forecast to remain at between $19.7 million and $18.7 million ($2019–20) in the last two years of the current period. These costs indicate Ergon Energy's opex has been higher over the current regulatory control period than would otherwise be the case. To the extent these costs are not ongoing at this level, and can achieve permanent improvements in the efficiency of Ergon Energy's operations, this opex in the current regulatory control period will contribute to lower opex in the 2020–25 regulatory control period.[92]

Table 6.5 Ergon Energy's actual and forecast reform costs over the current regulatory control period, ($ million, 2019–20)

	2015/16	2016/17	2017/18	2018/19	2019/20
Operational improvements	46.6	15.9	15.0	15.7	10.6
Non-recurring costs	3.1	2.2	2.6	4.0	8.1
Total	49.7	18.1	17.6	19.7	18.7

Source: AER analysis; Ergon Energy, *Information request 37* – Q2, 11 June 2019, p. 3; Ergon Energy, *Information request 56* – Q10, 17 July 2019, pp. 14-15.

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

Taken together, Ergon Energy's revealed cost information supports the view that while it has been relatively inefficient over the first three years of the current regulatory control period (with a level of opex above that set in our October 2015 final decision), its forecast cost savings in 2018–19, its proposed base year, will reduce its opex to a more efficient level that is consistent with that set in our October 2015 final decision. In addition, Ergon Energy is forecasting to do this while incurring significant reform costs, which suggests capacity for further reductions in opex from 2020–21 as these reform costs drop out of the business's opex and the longer term costs savings they are targeting begin to be realised.

Benchmarking average opex efficiency over time

Given our revealed cost analysis supports a view that Ergon Energy has only marginally improved its opex efficiency in recent years and its current level of opex may be inefficient, we must rely on our economic benchmarking tools to test the efficiency or material inefficiency of Ergon Energy's opex.[93]

Benchmarking broadly refers to the practice of comparing the economic performance of a group of service providers that all provide the same service to assess their relative

[92] The decrease in operational improvement and non-recurring costs between 2015—16 and 2016–17 is the primary driver of the significant decrease in total opex between these two years observed in Figure 6.4.

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

performance. Our Annual Benchmarking Report includes information about the purpose and use of economic benchmarking, and details about the techniques we use to benchmark the efficiency of distribution businesses in the NEM.[94]

Ergon Energy's initial proposal included benchmarking and category analysis in support of the efficiency of its estimated base year opex.[95] Frontier Economics, in a report prepared for Ergon Energy, assessed the efficiency of Ergon Energy's estimated base opex using a similar benchmarking methodology to that which we applied in our November 2018 draft determinations for the NSW distribution businesses.[96]

The Frontier Economics analysis used four econometric models[97] with both the AER's 2015 OEF adjustment (consistent with the approach to OEFs we used in the November 2018 draft determination for NSW distributors) and the Sapere-Merz OEF adjustment developed as part of an AER initiated industry wide review of OEFs.[98]

OEFs are factors that our benchmarking models do not directly account for (e.g. climate, geography, legislative obligations). These may materially affect the operating costs in different jurisdictions and hence may have an impact on our measures of the relative efficiency of each distribution business. Given this we also consider OEFs as a part of our benchmarking analysis.

Ergon Energy states that its benchmarking demonstrates that:

> '… our … base year opex … is efficient, and …there is no justification for the AER to make a further base year efficiency adjustment. This is true even under the highly conservative OEF adjustment of 13.6%, which covers only three of our many relevant OEFs.'[99]

Our preferred approach is to benchmark a business's efficiency on the basis of its average efficiency over time (using a period-average efficiency score from our econometric and opex multilateral partial factor productivity (MPFP) models). We

94 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2018. Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/annual-benchmarking-report2018

95 Frontier Economics, *AER Benchmarking - A report prepared for Energy Queensland,* 15 January 2019; Ergon Energy, *6.003 - Base Year Opex Overview 2020-25*, January, 2019, pp. 20-34.

96 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 48. For an example of the benchmarking method applied in the November 2018 draft determinations for the NSW distribution businesses, see AER, *Draft Decision, Ausgrid Distribution determination, 2019-24, Attachment 6 – Operating expenditure*, November 2018, pp. 6-31-6.33.

97 Cobb-Douglas stochastic frontier analysis (SFACD), Cobb-Douglas least squares econometrics (LSECD), Translog stochastic frontier analysis (SFATLG) and Translog least square econometrics (LSETLG).

98 Frontier Economics, *AER Benchmarking - A report prepared for Energy Queensland,* 15 January 2019; Ergon Energy - *6.003 Base Year Opex Overview 2020-25*, January 2019, pp. 20-34; AER, *Review of Operating Environment Factors for Distribution Network Service Providers*, see: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-operating-environment-factors-for-distribution-network-service-providers/initiation

99 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 48.

consider that this is a better approach than looking at the efficiency of a single year (such as the base year) as this recognises that opex is generally recurrent, but with some degree of year-to-year volatility.

Our benchmarking results indicate that Ergon Energy has been relatively inefficient over the 2006-17 period when compared to other distributors in the NEM.[100] Figure 6.5 shows that over this period Ergon Energy ranks 10th out of 13 distribution businesses based on the average efficiency scores from four economic benchmarking models[101], with scores ranging from 0.52 (Stochastic Frontier Analysis Cobb Douglas (SFACD) model) to 0.55 (opex MPFP). These results have not been adjusted for OEFs not already captured in the modelling and so they do not account for some factors beyond a distributor's control that can affect its benchmarking performance (see below for further discussion, including Box 1).

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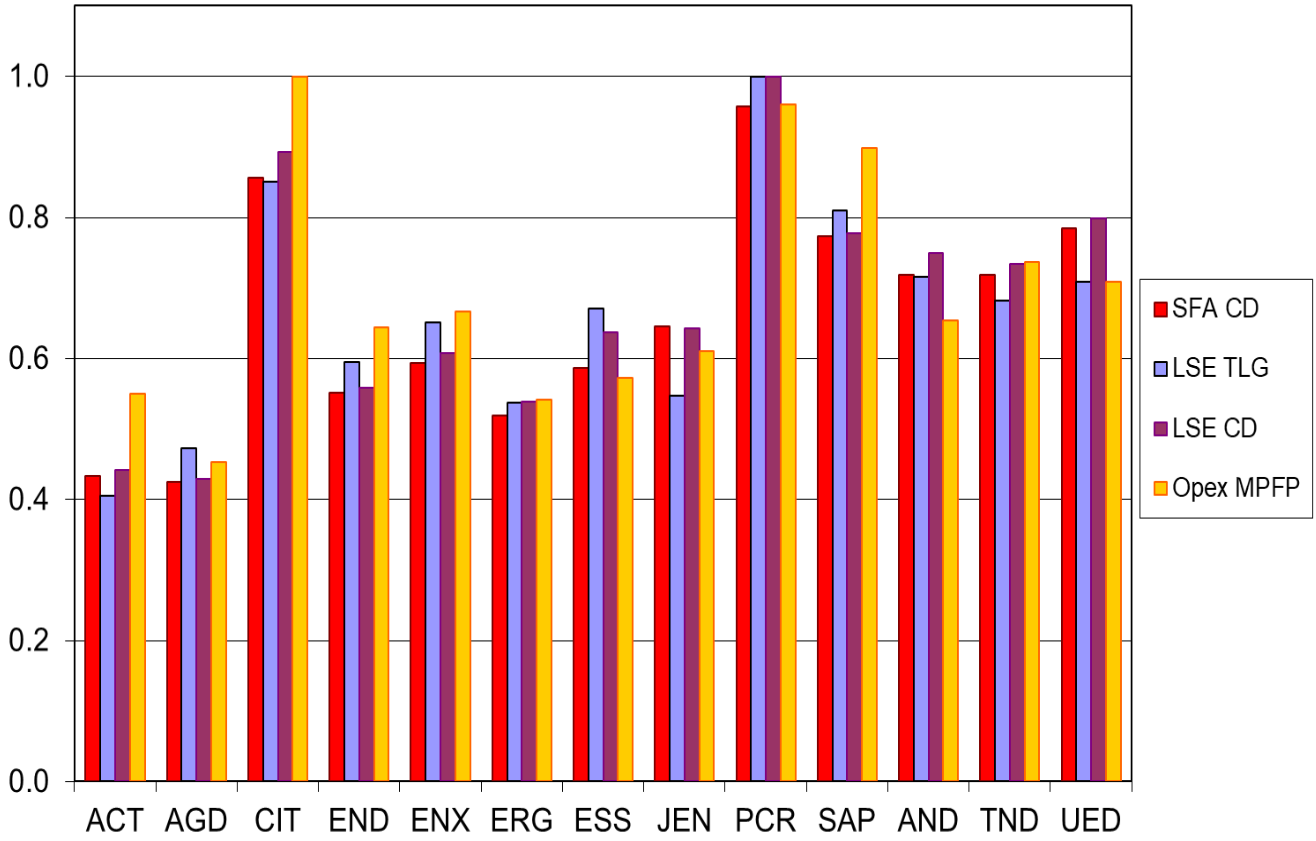
100 The AER's *2018 Annual Benchmarking Report* was published in November 2018. Since then some of the electricity distribution businesses have updated the input data used in the 2018 report. We have incorporated the corrected data into the benchmarking report data set and recalculated the 2018 results. These results are available in the Economic Insights, *2018 Annual Benchmarking Report Data Update*, 8 October 2019 at: https://www.aer.gov.au/networks-pipelines/network-performance/annual-benchmarking-report-distribution-and-transmission-2018

101 Economic Insights, *2018 Annual Benchmarking Report Data Update*, 8 October 2019.

Figure 6.5 Ergon Energy's average opex efficiency scores, 2006–2017



Source: Economic Insights, *2018 Annual Benchmarking Report Data Update*, 8 October 2019.

It can take some time for more recent improvements in efficiency by previously poorer performing distributors to be reflected in period average efficiency scores. Considering this, we have also examined Ergon Energy's average performance over the shorter and more recent 2012–17 time period.

These results show that while Ergon Energy's average efficiency scores across the models are higher compared to the longer time period, they continue to indicate relative inefficiency when compared to other distributors in the NEM. Over the 2012–17 time period, Ergon Energy ranks 9th out of 13 distribution businesses based on the average efficiency scores from five economic benchmarking models, with scores ranging from 0.56 (SFACD model) to 0.64 (opex MPFP).[102] Again, these results have not been further adjusted for OEFs.

To understand the potential drivers of relative inefficiency observed above we have also examined partial performance indicators (PPIs) – a different method of

[102] AER, 2018 *Annual Benchmarking Report Update,* 8 October 2019.

benchmarking. PPIs can be used to compare the total or category specific cost performance of businesses in delivering a given type of output. Although they are more simplistic measures, the PPI results can provide further insights and evidence to cross check our economic benchmarking.[103]

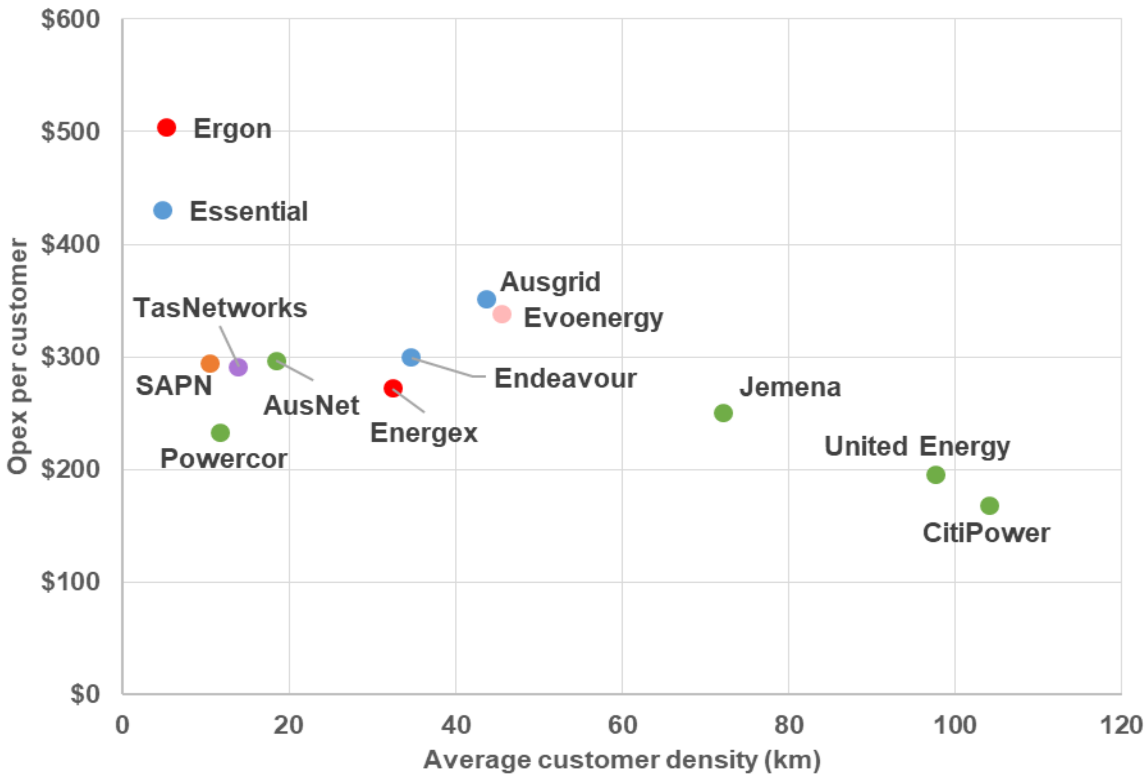
Figure 6.6 shows each distribution business's average opex per customer controlling for average customer density calculated over the 2014–18 time period. We note that on a 'per customer' metric, large rural distribution businesses (such as Ergon Energy and Essential Energy) will perform poorly relative to others in suburban and metropolitan areas. This is because typically, the longer and sparser a distribution business's network, the more assets it must operate and maintain per customer. Conversely, on 'per km' metrics, large rural distribution business will perform better because their costs are spread over a longer network.

Figure 6.6 plots average opex per customer against customer density,[104] to enable readers to visualise and account for these effects when interpreting the results.

[103] The PPIs support other benchmarking techniques because they provide a general indication of comparative performance of the DNSPs in delivering a specific output. While PPIs do not take into account the interrelationships between outputs (or the interrelationship between inputs), they are informative when used in conjunction with other benchmarking techniques.

[104] Defined as number of customers per route line km or per circuit line km.

Figure 6.6 Ergon Energy's opex per customer, 2014–18 ($2019–20)



Source: AER, *Partial Performance Indicator Analysis*, 8 October 2019.

The results shows that using the 'per customer' PPIs, Ergon Energy has significantly higher average opex per customer over the 2014–18 time period relative to other distribution businesses in the NEM, as well as relative to peer businesses with similar customer density such as Essential Energy. Of the main opex cost categories, the PPI analysis indicates that Ergon Energy has particularly high average total overhead costs per customer, and high emergency response costs per customer relative to other networks and relative to peer businesses with similar levels of average customer density.[105]

As expected, Ergon Energy's relative cost performance is significantly better on 'per km' PPIs that measure cost per kilometre of circuit line length controlling for average

[105] These results are broadly similar to the PPI analysis provided by Ergon Energy in its initial proposal (see: Ergon Energy, *6.003 Base Year Opex Overview*, January 2019, p. 24). We note that Ergon Energy calculated its PPIs using both an average over the 2012-17 time period and data for 2017. Generally, Ergon Energy's relative performance across the PPI analysis improved when PPIs were calculated using data for 2017 only compared to data averaged across 2012-17. This is suggestive of a relative improvement in opex efficiency in 2017 relative to earlier years. These results are also similar to the PPI analysis based on data from the 2013-17 time period published in the AER's *2018 Annual Benchmarking Report electricity distribution network service providers*. See: https://www.aer.gov.au/system/files/AER%202018%20distribution%20network%20service%20provider%20benchmarking%20report%20_0.pdf

customer density and calculated over the 2014–18 time period. This analysis shows that Ergon Energy has significantly lower average opex per kilometre of circuit line length over the 2014–18 time period relative to most distribution businesses in the NEM with higher customer density.[106] However, when compared to its closest peer businesses with similar levels of customer density, such as Essential Energy, Ergon Energy's average costs per km tend to higher. Ergon Energy's average opex per km of circuit line length is $6864 ($2019–20) compared to $5362 ($2019–20) for Essential Energy.[107] This pattern is repeated for average emergency response opex per km of circuit line length (Ergon Energy $307 ($2019–20) compared to Essential Energy $205 ($2019–20)) and average total overheads per km of circuit line length (Ergon Energy $2901 ($2019–20) compared to Essential Energy $1615 ($2019–20)).[108]

Our PPI analysis appears to support the economic benchmarking analysis and our view that Ergon Energy's opex has been relatively inefficient historically.

Benchmarking the efficiency of the base year opex

Given the evidence outlined above of the relative inefficiency of Ergon Energy's opex over the 2006-17, 2012-17 and 2014–18 time periods, we have undertaken additional economic benchmarking to more directly test the efficiency of Ergon Energy’s estimated 2018–19 base year opex.

Figure 6.7 presents the results of opex MPFP benchmarking, which allows for the comparison of opex productivity levels between service providers and across time. The chart shows all distributors in the NEM using actual opex up to 2017–18 and opex forecasts for Ergon Energy and Energex's proposed base years in 2018–19. We note these opex MPFP results have not been further adjusted for OEFs and so do not account for some factors beyond a distributor's control that can affect its costs and benchmarking performance.

Figure 6.7 shows that while Ergon Energy's opex MPFP score has improved somewhat since 2015–16, the first year of the current regulatory control period, Ergon Energy's MPFP scores based on its 2017–18 actual opex and its estimated 2018–19 base year opex continue to place it as a relatively poor performer amongst distributors in the NEM. In terms of comparative performance, Figure 6.7 shows that Ergon Energy has improved marginally from 12th place out of 13 distributors in terms of average MPFP score over the 2006–2019 time period, to 11th place in 2017–18 and an estimated 10th place in 2018–19.[109] We note that this marginal relative

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106 AER, *Partial Performance Indicator Analysis*, 8 October 2019.

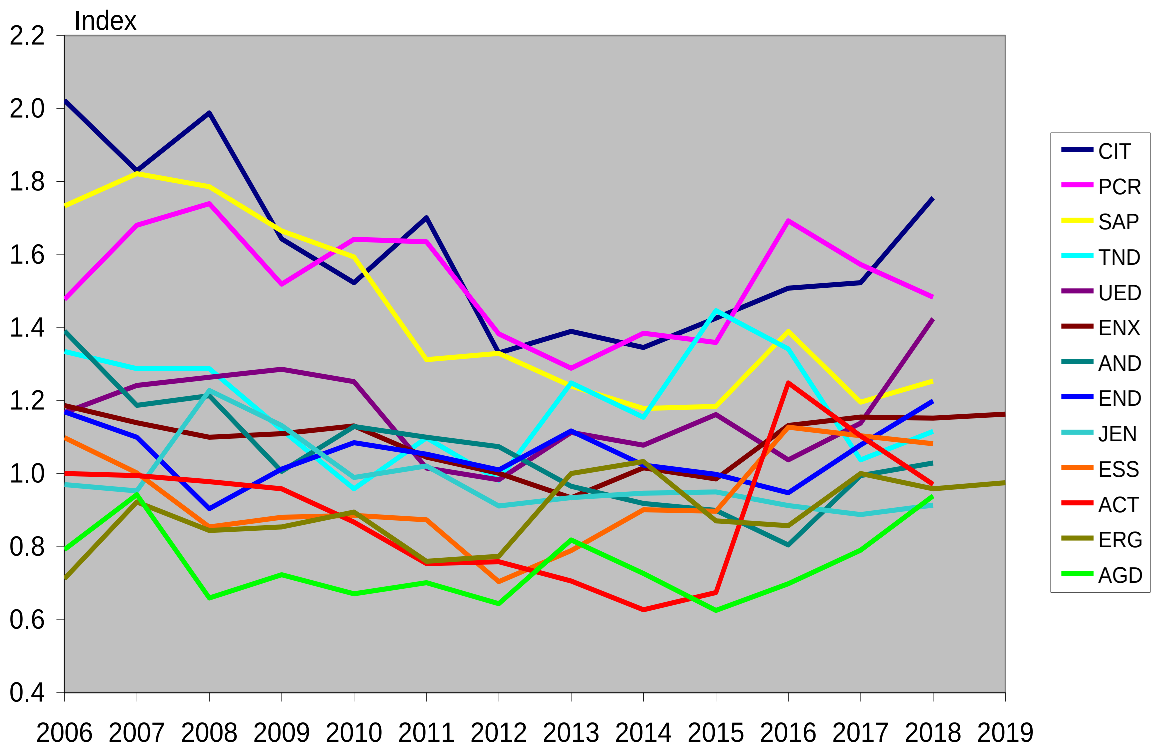
107 AER, *Partial Performance Indicator Analysis*, 8 October 2019.

108 AER, *Partial Performance Indicator Analysis*, 8 October 2019.

109 A comparison of Ergon Energy and Energex's opex MPFP scores in 2018–19 and opex MPFP scores in 2017-18 involves comparing actual scores in 2017-18 with forecast scores for 2018–19 based on estimates of Ergon Energy and Energex's base year opex. This comparison assumes other distribution businesses scores do not change in 2018–19.

improvement in opex productivity has occurred during a time of significant increases in opex MPFP scores of some of the other distributors in the NEM.

Figure 6.7 Opex multilateral partial factor productivity, 2006–2018, with Ergon Energy and Energex forecasts to 2019



Source: Economic Insights, *Memorandum Productivity of Energex's and Ergon Energy's proposed base year opex*, 8 July 2019.

Note: The opex MPFP scores have not been further adjusted for OEFs. Consistent with our approach of using the most recently available data, the chart uses actual opex for all DNSPs up to 2017–18 and opex forecasts for Energex and Energex for 2018–19.

We have also examined the efficiency of Ergon Energy's estimated 2018–19 base year opex using the results of our econometric modelling adjusted for cost differences driven by OEFs not already captured in the modelling. Our econometric models produce period-average opex efficiency scores for distributors across the 2006–17 and 2012–17 periods.[110] We use these results to estimate the level of opex an efficient benchmarked service provider operating in Ergon Energy's circumstances would

[110] We have calculated estimates of benchmarked efficient base year opex based on the longer time period and shorter (relatively more current) period. We note it may take some time for improvements in efficiency by previously poor performing distributors to be reflected in the efficiency scores and the use of the shorter time period will produce estimates that better reflect more recent improvements in actual opex efficiency. For more detail, please see Box 6.1. We will update our econometric modelling with data for 2018–19 and the results from our 2019 Annual Benchmarking Report for distribution service providers for the final decision.

require in 2018–19 to deliver its network services. For each model, this estimate is also adjusted to account for business-specific OEFs. We then compare these estimates of benchmarked efficient 2018–19 opex on a 'like for like' basis to Ergon Energy's estimated 2018–19 base year opex. Where Ergon Energy's base year opex is similar to, or below, our estimates of benchmarked efficient opex, this gives us confidence that Ergon Energy's opex is not materially inefficient. Where Ergon Energy's estimated base year opex is above our estimates of efficient opex this provides evidence of material inefficiency.

Box 6.1 summarises the methodology we have followed to produce the estimates of efficient opex presented below and make our 'like for like' comparison of base year opex numbers. Further details are set out in a spreadsheet that we have published alongside this draft decision on our website.

Box 6.1 How we generate estimates of benchmarked efficient opex

To derive our estimates of benchmark efficient opex for a distributor, and in this case Ergon Energy, as shown in Figures 6.8 and 6.9, we use the following steps for each of the econometric models.

We first average the distributor's (Ergon Energy's) actual opex over each of the 2006–17 and 2012–17 periods. We use the two time frames because each has their advantages. The use of the shorter time period can produce estimates that better reflect more recent improvements in opex efficiency as it may take some time for efficiency improvements by previously poor performing distributors to be reflected in period-average efficiency scores. The advantage of the longer time period is that it can better smooth out year-to-year fluctuations and better represents some operating environment factors (OEFs) in the longer term.[111]

We then draw on our benchmarking scores from our econometric benchmarking models to assess whether to make an efficiency adjustment to the distributor's (Ergon Energy's) period-average opex for each of the two periods. For each of the models, the size of the efficiency adjustment is calculated by comparing the distributor's (Ergon Energy's) efficiency scores over 2006–17 and 2012–17 against a benchmark comparison score of 0.75 (after adjustment for OEFs as discussed below). The benchmark comparison score reflects the upper quartile of possible efficiency scores by distribution businesses, and reflects our conservative approach to setting a benchmark comparison point. This is consistent with the comparison point we adopted in our April 2015 decision for Ergon Energy and subsequent decisions in November 2018 for NSW distributors.[112]

[111] We have not included a SFA TLG estimate of benchmarked efficient base year opex for Ergon Energy under the 2006-17 time period. The Economic Insights 2018 report notes that the SFA TLG model is statistically robust over the 2012–17 dataset, but does not produce useable results over the entire 2006–17 sample. This is because it violates statistical monotonicity requirements to a much greater extent over the full period. See Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Annual Benchmarking Report*, 9 November 2018, p. 19.

[112] AER, *Preliminary Decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 7 Operating Expenditure*, April 2015, pp. 7-261-7-273; AER, *Draft Decision, Ausgrid Distribution determination, 2019-24,*

The benchmark comparison point is adjusted to account for potential differences in costs due to OEFs between the distributor (Ergon Energy) and the relevant benchmark efficient service providers in the NEM.[113] For this decision, we have applied 'material only' OEFs as measured by the Sapere-Merz OEFs with a vegetation management OEF also included.[114] This is a change from the previous approach used in our April 2015 decision for Ergon Energy and Energex, and subsequent decisions in November 2018 for NSW distributors, which applied OEF adjustments that accounted for both material and immaterial OEFs. This change reflects a view that the 2015 OEFs now represent an overly conservative estimate of the impact of OEFs on businesses' costs, particularly given that Sapere-Merz's advice expanded on, and refined, our previous analysis of OEFs in our 2015 opex decisions, including its advice on which OEFs were material.

We then apply this efficiency adjustment (if any) to the distributor's (Ergon Energy's) average level of opex over 2006–17 and 2012–17 (period-average opex). This results in an estimate of period-average opex that we consider is not materially inefficient at the midpoint of each of the 2006–17 and 2012–17 periods.

This period-average opex estimate is then rolled forward to the 2018–19 base year using the rate of change formula. This results in an estimate of benchmarked efficient base year opex that we consider is not materially inefficient.

Our estimates of benchmarked efficient base year opex for a given distributor reflect their network services opex under their 2013 CAM. This is because our benchmarking uses network services opex calculated under the CAMs in place in 2013.[115] To enable us to make a 'like for like' comparison, we compare these estimates to the distributor's proposed base year network services opex. Where a distributor has made a CAM change since 2013, we may also need to ask the distributor to recast the its proposed base opex amount under its 2013 CAM.

These calculations are set out in a spreadsheet that we have published alongside this draft decision. Appendix A to this attachment sets out why we are moving to a material-only OEF approach and our method for updating and calculating a vegetation management OEF used with the material OEFs.

Figure 6.8 and 6.9 present the range and average of our estimates of benchmarked efficient base year opex over the longer and shorter time periods (2006–17 and 2012–

Attachment 6 – Operating expenditure, November 2018, pp. 6-31-6.33; AER, *Draft Decision, Endeavour Energy Distribution determination, 2019-24, Attachment 6 Operating expenditure*, November 2018, pp. 6-27-6.29.

113 As noted above, OEFs are factors that our benchmarking models do not directly account for (e.g. climate, geography, legislative obligations). These may materially affect the operating costs in different jurisdictions and hence may have an impact on our measures of the relative efficiency of each distributor.

114 In October 2018, we published a report from consultants Sapere Research Group and Merz Consulting (Sapere-Merz) that reviewed material differences in operating environments of distribution businesses in the NEM. The report identified a limited number of OEFs that materially affect the costs of each distribution business. However, Sapere-Merz acknowledged that its analysis was preliminary and could be improved through better data. We intend to consult further with the distribution industry to refine the assessment and quantification of OEFs. See: Sapere Research Group, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, December 2017.

115 AER, *2018 Annual Benchmarking Report,* November 2018.

17), and compare these to Ergon Energy's estimated 2018–19 base year opex. As noted in Box 6.1, to allow for a 'like for like' comparison, we requested Ergon Energy recast its proposed base year opex on the basis of network services opex under the CAM in place in 2013.[116] This is to be consistent with opex data used for benchmarking analysis. The opex is shown by the green columns in Figures 6.8 and 6.9.

The results using the longer time period show that Ergon Energy's recast estimated base year network services opex is slightly above the average of our three estimates of benchmarked efficient network services opex. This supports a finding that Ergon Energy's base year network services opex is materially inefficient. However, using the shorter time period results, which place more weight on recent opex, Ergon Energy's recast estimated base year network services opex is below the average of our four estimates. This supports a finding that Ergon Energy's recast base year network services opex is not materially inefficient.

As a final step, we consider whether Ergon Energy's recast base year network services opex is a reasonable proxy of its estimated base year opex. Ergon Energy's estimated 2018-19 base year standard control services (SCS) opex under its current CAM is $377.0 million ($ million, 2019–20). Its recast base year network services opex in 2013 CAM terms is $365.3 million ($ million, 2019–20). The difference between the two numbers is primarily attributable to SCS metering opex, which is not included in network services opex, and changes to Ergon Energy's CAM since 2013.

We consider it is reasonable to assume that the SCS metering opex is not materially inefficient. This is because metering is typically delivered by the same labour force, and under the same management as network opex, which, as set out below we find not to be material inefficient.

For the draft decision, we consider that the opex attributable to CAM changes since 2013 is also efficient. Our October 2015 final decision did not include the increase in opex proposed by Ergon Energy under its 2015–16 CAM change.[117] Ergon Energy has been operating under the 2015 CAM over the current control period with an EBSS in place and so has faced a strong incentive to not incur unnecessary costs. However, we will consider this position further for the final decision. More broadly, the potential for a growing divergence between the 2013 CAMs our benchmarking operates under, and the current CAMs distributors have in place is an issue we are considering as part of our ongoing benchmarking development work.

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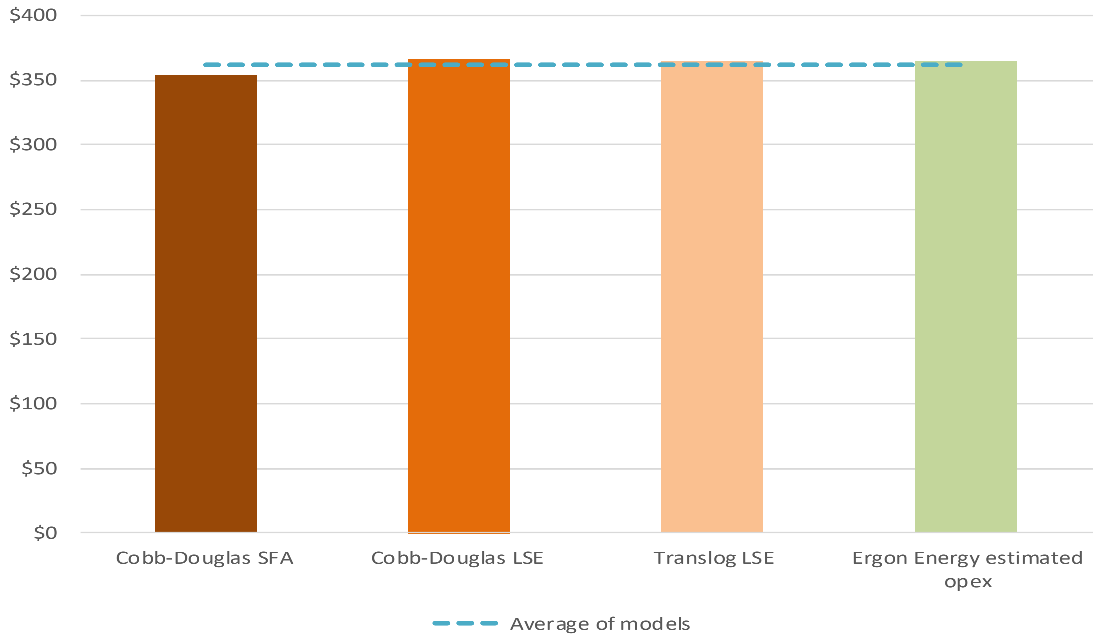
116 Ergon Energy, *Information request 41* – Q1, 4 June 2019, p.4.

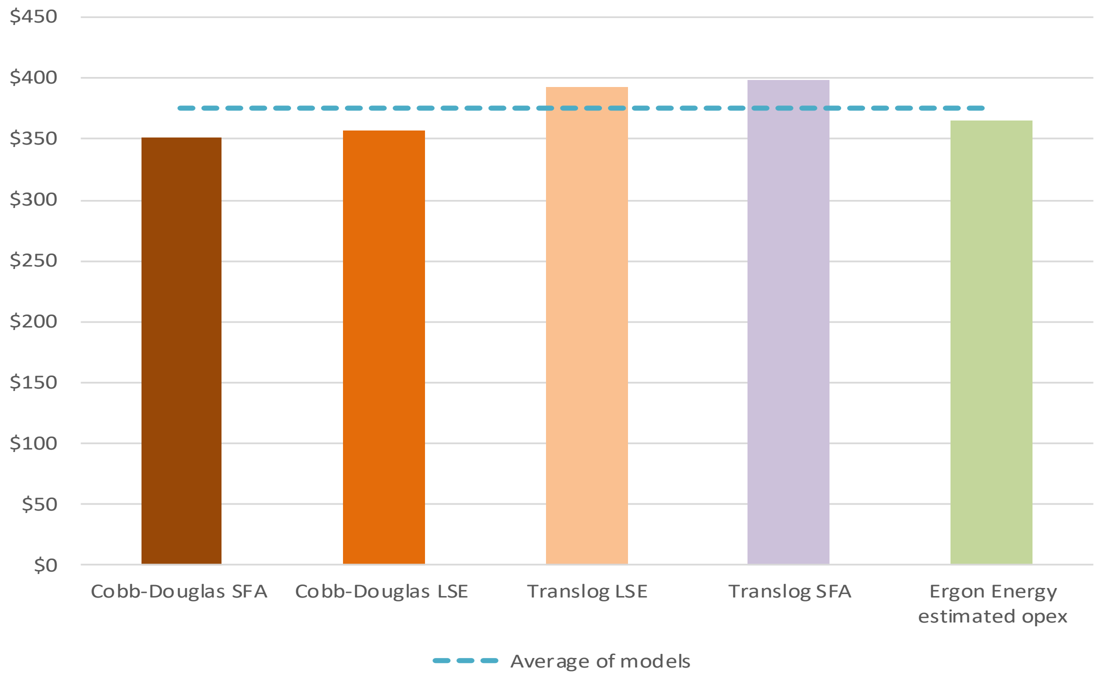
117 AER, *Preliminary Decision, Ergon Energy determination 2015–16 to 2019–20, Attachment 7 Operating Expenditure*, April 2015, p. 7-38.

Figure 6.8 AER estimates of benchmarked efficient base year opex and Ergon Energy's estimated base year opex in 2018–19 ($ million, 2019–20), 2006–17 time period



Source: AER analysis. Economic Insights, *2018 Annual Benchmarking Report Data Update*, 8 October 2019.

Figure 6.9 AER estimates of benchmarked efficient base year opex and Ergon Energy's estimated base year opex in 2018–19 ($ million, 2019–20), 2012–17 time period



Source: AER analysis. Economic Insights, *2018 Annual Benchmarking Report Data Update*, 8 October 2019.

Taking the opex MPFP and econometric benchmarking results together, we have concluded that on balance these results support the finding that Ergon Energy's estimated base year opex is at a level that is consistent with what an efficient benchmarked service provider operating in Ergon Energy's circumstances would require in 2018–19 to deliver its network services, and therefore, is likely to not be materially inefficient. Consequently, we make no efficiency adjustment and use Ergon Energy's current estimate of base year opex for our alternative estimate of base opex.

However, we note that this analysis is finely balanced. Ergon Energy's estimate of its base year opex, which includes assumed efficiency savings in 2017–18, is on the borderline of material inefficiency. A relatively small increase in Ergon Energy's base year opex would likely change our assessment. We will review this position and update our benchmarking analysis for our final decision, taking into account the actual opex in 2018–19 included in Ergon Energy's revised proposal and the results of the final 2019 Annual Benchmarking Report.

The assessment of the efficiency of Ergon Energy's base year opex was a key issue raised in submissions to the AER. The CCP14 stated that they looked forward to the AER closely examining whether the proposed Ergon Energy base year of 2018–19 was “not materially inefficient”, noting that:

> 'While the savings achieved in the last couple of years are not reflected in the AER benchmarking results … (latest year is 2016–17), it remains to be seen if these changes, along with application of the latest Sapere-Merz OEFs, have been enough to meet the AER’s benchmark.'[118]

The ECA submission included analysis by Dynamic Analysis which focused on how Ergon Energy has performed against AER opex benchmarks, and an evaluation of the robustness of the base year. ECA noted that:

> The key question raised in this analysis is whether Energex and Ergon Energy’s performance in the mid-range of the AER’s opex benchmarks is justified, and whether consumers should expect the networks to achieve deeper efficiencies.[119]

QCOSS noted that our 2018 Annual Benchmarking Report indicates that Ergon Energy does not compare favourably with other networks, particularly in the areas of overhead costs and capacity utilisation, and they urge the AER to consider whether this indicates scope for a reduction in opex.[120]

We have considered the issues raised in submissions in our analysis of Ergon Energy's base opex. We agree with stakeholders' views that Ergon Energy has been

118 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020-25 Regulatory Proposals*, May 2019, p.13.

119 Energy Consumers Australia, *AER Issues Paper: QLD electricity distribution determinations Energex and Ergon Energy 2020 to 2025 Submission*, June 2019, p. 15.

120 Queensland Council of Social Services, *QLD electricity distribution determinations – Energex and Ergon 2020 to 2025, QCOSS Submission: AER Issues Paper*, May 2019, p. 11.

relatively inefficient over time and that relatively high overhead costs have contributed to this inefficiency. However, as outlined above, our benchmarking analysis of Ergon Energy's estimated base year opex supports a finding that this level of opex is likely to not be materially inefficient. However, as noted above, Ergon Energy's estimated base opex is on the borderline of material inefficiency and we will review this position when we have Ergon Energy's actual opex in 2018–19.

Adjustments to base opex

Adjustments may be made to base year opex prior to applying the rate of change to ensure that it reflects the efficient and recurrent level of opex over the forecast period. In past resets we have made a range of base adjustments, including:

- Removal of non-recurrent costs
- Efficiency adjustments
- Changes in CAM
- Changes in capitalisation approach
- Movements in provisions.

As noted in section 6.2, Ergon Energy proposed adjustments to its base year opex, for the following drivers:[121]

- Positive base adjustments, comprising:
    - an adjustment to include the impact of the new CAM, which increases its base opex by $15.7 million ($2019–20) per year, and its forecast opex over the 2020-25 regulatory control period by $78.7 million ($2019–20)
    - an adjustment for service classification changes, which increases its base opex by $0.1 million ($2019–20) per year, and its forecast over the 2020-25 regulatory control period by $0.4 million ($2019–20)
- Negative base adjustments reflecting the 'reform' costs associated with the merger with Energex, comprising:
    - the removal of one-off costs identified as “operational improvements", which decreases its base opex by $7.7 million ($2019–20), and its forecast over the 2020–25 regulatory control period by $38.3 million ($2019–20)
    - the removal of one-off costs identified as “non-recurring costs”, which decreases its base opex by $10.5 million, and its forecast by $52.4 million over the 2020–25 regulatory control period ($2019–20)

121 Ergon Energy, *1.004 – Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 46-47; Ergon Energy, *6.008 – Opex forecast – SCS JAN19*, January 2019; AER analysis.

- a reduction for expected merger savings in 2019–20, which decreases its base opex by $7.3 million ($2019–20), and its forecast by $36.3 million over the 2020–25 regulatory control period ($2019–20).

Of these, we have only included an adjustment for changes to service classification in our alternative estimate of opex, noting we have included a different amount to that proposed by Ergon Energy. We have not included the proposed adjustment for the new CAM in our alternative estimate as at this stage Ergon Energy has not been able to adequately explain and justify the proposed increase in opex. As a result, at this stage we cannot conclude the cost increases for the new CAM are prudent and efficient. We have also not included the proposed negative adjustments in our alternative estimate as we understand that the "operational improvements" and "non-recurring" costs will continue to be incurred at some level through the 2020–25 regulatory control period, and the 2019–20 merger savings have not yet been realised

For this draft decision we have not made an adjustment for movement in provisions, which we will do for the final decision with the availability of actual opex for 2018–19. This is in line with our standard approach.

In the sections below we provide more detailed discussion of each of these adjustments and the reasons for our draft decision.

Cost allocation method

We have not included the additional costs proposed by Ergon Energy to account for the new CAM. Ergon Energy has not been able to adequately explain and justify this proposed increase in opex. The reasons for this are outlined below. In Appendix B, for completeness we have detailed our views about the gaps in the information we received from Ergon Energy and what information we would require should Ergon Energy wish to propose a similar adjustments in its revised proposal.

In its proposal, Ergon Energy proposed an upward adjustment to its proposed base year opex of $15.7 million ($2019–20) for what it described as “changes in our CAM,” referring to the new CAM that will apply to Ergon Energy in the 2020–25 regulatory control period.[122] The proposal did not provide any further explanation or detail of what the drivers of this adjustment were or how the proposed amount was calculated.

Through a series of information requests and several meetings with Ergon Energy and Energex (who proposed similar changes with a resulting cost increase of $7.2 million ($2019–20)), we now understand that the adjustment represents the net impact on the level of indirect costs within base opex[123] from three accounting-related changes.[124] In particular:

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[122] Ergon Energy, *1.004 – Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 46-47.

[123] We understand these indirect costs cover corporate overheads, network overheads and non-network overheads. We use the terms indirect costs and overheads interchangeably in this document.

- a decrease in indirect costs to account for the dissolution of SPARQ, and adoption of in-house ICT services, resulting in a change in the way ICT costs are accounted for (SPARQ changes)
- an increase in indirect costs to achieve alignment between current Energex and Ergon Energy accounting policy approaches (costing treatment alignment)
- an increase in indirect costs to account for changes to reflect the new CAM that will take effect from 1 July 2020 (change to new CAM).

Ergon Energy and Energex also explained that these changes, and the corresponding estimates for each element, were calculated through a largely 'top down' method, rather than through a bottom-up exercise.[125] While we appreciate the challenges of explaining a largely top-down exercise, we need to have sufficient evidence to satisfy ourselves that the resulting cost changes are prudent and efficient.

Table 6.6 shows for each of these elements the corresponding cost changes based on the information and understanding we gathered through the information request process. Due to the inter-related nature of some of these changes, we present the adjustments for both Ergon Energy and Energex.

As can be seen in table 6.6 the net change from all of these adjustments is broadly consistent with the increase in opex proposed by Ergon Energy and Energex as changes in the CAM ($15.7 million ($2019–20) for Ergon Energy and $7.2 million ($2019–20) for Energex). However, it was only through the information request process and our analysis of the information provided that we were able to compile this overall picture. Ergon Energy and Energex were not able to easily provide information about the different nature or the drivers of the changes, with some of the information provided having changed over time. There was also a lack of supporting evidence for many of these changes.

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124 Ergon Energy, *Information request 40 – Q1*, 11 June 2019, p. 2; Ergon Energy, *Information request 51 – Q12-16*, 27 June 2019, pp. 8-10; Ergon Energy*, Information request 56 – Q15-23*, 17 July 2019, pp.16-18; Ergon Energy*, Information request 59 – Q1*, 8 August 2019, p. 1.

125 Ergon Energy, *Information request 51 – Q12c*, 27 June 2019, p. 9.

Table 6.6 Components of Ergon Energy's and Energex's proposed CAM change and impact on indirect costs ($ million, $2019–20)

Type of adjustment	AER understanding of movement/driver	Energex	Ergon Energy
SPARQ changes	Removal from overheads of ICT asset service fee payments, resulting from dissolution of SPARQ	-13	-16
Costing treatment alignment			
	Credit returns - to be treated as overheads		+2
	Fleet operations - to be treated as overheads		+4
	Training - to be treated as direct costs	-4	
Costing treatment alignment	Alignment of Ergon Energy's capitalisation approach to Energex's, resulting in the allocation of non-capitalisable corporate costs which reduce the overhead cost allocated to capital expenditure	0	+17
Costing treatment alignment	Removal of change fund from overheads (Ergon Energy)	0	-4
Change to new CAM	Increased corporate overheads allocation of $20m (due to application of the corporate three factor method, in particular higher customer numbers in the south-east)	+21	0
Change to new CAM	Increased allocation resulting from various factors e.g. higher levels of labour expenditure, which contributes to a greater proportion of non-network costs allocated to standard control service opex.	+3	+4
Change to new CAM	Unspecified/unexplained residual		+8
All adjustments	Net movement	+7	+16

Source: Ergon Energy, *Information request 40 – Q1*, 11 June 2019, p. 2; Ergon Energy, *Information request 51 – Q12-16*, 27 June 2019, pp. 8-10; Ergon Energy, *Information request 56 – Q15-23*, 17 July 2019, pp.16-18; Ergon Energy, *Information request 59 – Q1-20*, 8 August 2019, pp.1-7; Energex, *Information request 34 – Q1*, 11 June 2019, p. 2; Energex, *Information request 41 – Q12-16*, 27 June 2019, pp. 6-8; AER analysis.

To illustrate this we note:

- The overall characterisation of the adjustments moved over time from a change related to the new CAM to three groups of broader accounting-related changes.[126] Similarly, the capitalisation change was originally described as a CAM alignment,[127] but subsequently it was confirmed to be related to a change in capitalisation policy and unrelated to the CAM.[128] In terms of the costs associated with these changes, for Ergon Energy most are unrelated to the change to the new CAM (in absolute value terms only 22 per cent of the total adjustment relate to the new CAM).[129]
- For some of the changes, the estimated amounts changed over the information gathering process, e.g.
  - The amount for the capitalisation change for Ergon Energy changed from +$22 million ($2019–20) to +$17 million ($2019–20)[130]
  - The new CAM change amount for Energex changed from +$35 million ($2019–20) to +$24 million ($2019–20), reflecting a change in the starting amounts for SCS opex and ACS opex indirect costs.[131]
- For the accounting alignment adjustments in particular, it was not clear whether these adjustments to indirect opex took into account offsetting impacts on direct opex.
- For some of the changes, the estimated amounts were subject to uncertainty in either amount and/or driver. For example,
  - The businesses provided an estimate of the adjustment to reflect the alignment of Ergon's capitalisation approach to Energex's, but stated that this is a net estimate and likely to also encompasses a change (likely decrease) in corporate allocation to Ergon Energy's standard control service opex from application of the 3-factor method in the new CAM, whereby the former offsets the latter by around $17 million). However, the businesses were not able to identify the gross adjustment amounts.[132]
- Ergon Energy introduced a new change part way through the information gathering process in relation to removal of change fund from overheads.[133]

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126 Ergon Energy, *1.004 – Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 46-47; Ergon Energy, *Information request 51 – Q12c*, 27 June 2019, p. 9; Ergon Energy, *Information request 59 – Q1*, 8 August 2019, p. 1.

127 Ergon Energy, *Information request 40 – Q1*, 11 June 2019, p. 2.

128 Ergon Energy, *Information request 59 – Q7&9*, August 2019, pp. 2-3.

129 AER analysis, noting for Energex more of the changes are related to the new CAM (in absolute value terms 59 per cent of the total adjustment relate to the new CAM).

130 Ergon Energy, *Information request 56 – Q16*, 17 July 2019, p. 16.

131 Ergon Energy, *Information request 59 – Q18*, 8 August 2019, pp. 5-6.

132 Ergon Energy, *Information request 56 – Q22*, 17 July 2019, p. 18; Energex, *Information request 41 – Q15a*, 27 June 2019, p. 8.

133 Ergon Energy, *Information request 56 – Q16 and Q19*, 17 July 2019, pp. 16-17.

Taken together, this diminishes our confidence in Ergon Energy and Energex's proposed increases relating to changes in the CAM.

We have decided to exclude the proposed adjustments for CAM changes in our alternative estimate for the draft decision as we are not satisfied in the clarity of the explanation and evidence for these changes, and as a result we cannot conclude they are prudent and efficient.

However, we consider there is now sufficient understanding of the nature of the accounting-related changes that should enable Ergon Energy and Energex to provide a more detailed evidence based explanation in its revised proposal. We remain open to further consideration of this proposed adjustment were Ergon Energy and Energex to propose it (or similar) in its revised proposal. If proposed in the revised proposal, we would expect to see a clear, comprehensive and evidence based explanation of any changes. Given the 'top down' method employed, evidence of external or internal formal verification and audit of the proposed adjustments is encouraged and would lend weight to inclusion of these changes in our alternative estimate for the final decision.[134]

We note that not including these adjustments in our alternative estimate does not impact on our draft decision to accept Ergon's total opex proposal.

In Appendix B, we discuss each of the proposed adjustments in more detail and set out the nature of the further information that Ergon Energy and Energex may wish to provide in their revised proposals (in addition to evidence of external or internal verification and audit).

Service classification change

We have included an increase in our alternative estimate of base opex of $0.2 million ($2019–20) for Ergon Energy to account for the service classification change. This is a different (higher) amount to that proposed by Ergon Energy. The reasons for this are outlined below.

Ergon Energy proposed a positive adjustment of $0.1 million ($2019–20) for changes in service classification.[135] There was no detail on the change in service classification or explanation of the driver of this cost change provided in the proposal.

Following the information request process, we now understand that the proposed adjustment relates to emergency recoverable works (ERW) costs incurred when a customer or third party damages the network.[136] In support of the adjustment, Ergon

[134] We note that Energy Queensland did not undertake formal reviews or reconciliations of the application of the new CAM to 2018-19 data. Source: Ergon Energy, *Information request 56 – Q17*, 17 July 2019, p. 17.

[135] Ergon Energy, *1.004 – Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 46-47; Ergon Energy, *6.008 – Opex forecast – SCS JAN19*, January 2019.

[136] Ergon Energy, *Information request 40 – Q2a*, 5 June 2019, p. 2.

noted this service is now regulated having been previously unregulated and that “as the expenditure was not previously included in standard control service opex, the forecast for 2018–19 has been included as an adjustment."[137]

ERW is now a regulated standard control service. As noted in the Final Framework & Approach[138] for the current regulatory control period (2015–20), we did not “classify” this service in Queensland, meaning the service was until recently unregulated. Under the Final Framework & Approach applying to Ergon Energy for the 2020–25 regulatory control period, ERW will be subsumed into the common distribution services group and classified as a direct control and standard control service (and therefore regulated).[139]

Although we have classified this service as a standard control service, a distributor is still expected to seek recovery of the cost of these emergency repairs from the third party where possible. If a distributor is successful in recovering the cost of the emergency repairs from a third party, this payment or revenue will be netted off against the efficient opex incurred by a distributor in performing ERW. This prevents distributors from recovering the cost of emergency repairs twice–as a standard control charge across the broader customer base and from the responsible third party.

Consistent with the approach adopted in recent reset decisions, we have allowed an adjustment for ERW in our alternative estimate. As noted in the Ausgrid final decision, our intention in making the classification change to ERW costs, as outlined in its Final Framework & Approach, was that the reclassification would apply only to recovered ERW costs and so have zero net impact on network revenues and costs to consumers. For recent resets, some distribution businesses misinterpreted the Final Framework & Approach, to include unrecovered ERW works which we believe not to be an unreasonable misinterpretation.[140] We note the Framework & Approach wording on the ERW reclassification for future resets was updated to make clear that the change applies only to recovered ERW costs.[141]

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137 Ergon Energy, *Information request 40 – Q2a-2b*, 5 June 2019, p. 2.

138 AER, *Final framework and approach Energex and Ergon Energy*, *Regulatory control period commencing 1 July 2020-July 2025*, July 2018, p. 23.

139 We define ERW as the distributor's emergency work to repair damage following a person's act or omission, for which that person is liable (for example, repairs to a power pole following a motor vehicle accident). As ERW services are provided in connection with a distribution system, we consider this a distribution service. However, historically we have not classified this service, treating it as an unregulated distribution service because the cost of these works may be recovered through other avenues (e.g. under common law). That is, the distributor can seek payment of their costs to fix the network from the parties responsible for causing the damage, through the courts if necessary. Following the introduction of our ring-fencing guideline, classifying this service as an unregulated distribution service would require it to be ring-fenced. The benefits from not classifying this service are outweighed by the likely costs of having to establish ring-fencing arrangements (staff and office separation) for the provision of this service. To avoid these costs, we have classified ERWs as a direct control and standard control service.

140 AER, *Final Decision, Ausgrid Distribution Determination 2019 to 2024, Overview*, April 2019, p. 33.

141 AER, *Final framework and approach, AusNet Services, CitiPower, Jemena, Powercor and United Energy Regulatory control period commencing 1 January 2021*, January 2019, pp. 26-27.

Ergon Energy has proposed to include previously unrecovered ERW in its base opex and also stated in response to our questions that unrecovered ERW costs were not previously part of standard control services opex.[142] We have therefore accepted a base adjustment for ERW in this instance. We will not accept a similar adjustment in future resets.

In relation to the amount allowed for the adjustment, we have included in our alternative estimate an adjustment of $0.2 million ($2019–20) for Ergon Energy. This is a different (higher) amount to that proposed by Ergon Energy. We have calculated our adjustment on the basis of the approach adopted in our previous determinations of using the historical average unrecovered unregulated ERW costs. Specifically, our adjustment is based on the annual cost of repairing third party damage to its network (calculated using 3-year average historic actual costs) less the revenue recovered from parties found liable for causing the damage (calculated using 3-year average historic receipts from liable parties).[143]

In the information request process, Ergon Energy initially stated that the proposed amount represented an estimation of Ergon Energy's annual unrecovered ERW costs, based on historical actual costs as well as expected trends.[144] However, Ergon Energy later agreed to the approach adopted in our previous determinations as outlined above and put forward a revised classification adjustment consistent with our calculated adjustment for our alternative estimate.[145]

Negative base adjustments

Our alternative estimate does not include the removal of the negative base adjustments (non-recurring costs) from base opex as proposed by Ergon Energy. Our standard approach is to set opex based on a revealed cost approach of actual costs incurred. Information provided by Ergon Energy shows that while its intention was not to seek to recover these costs from consumers via opex, it has incurred these costs in the base year and will continue to incur them at some level over the forecast period.[146] The reasons for not including these adjustments in our alternative estimate are outlined below.

Our treatment of Ergon Energy's negative base adjustments in our alternative opex estimate also has implications for Ergon Energy's EBSS carryover amount (see the discussion below and Attachment 8).

In its proposal Ergon Energy proposed three negative base adjustments to 2018–19 base year opex. These reduce its base year opex forecast by $25.4 million ($2019–

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[142] Ergon Energy, *Information request 40 – Q2b*, 5 June 2019, p. 2.

[143] Ergon Energy, *Information request 51 – Q10*, 27 June 2019, p. 8.

[144] Ergon Energy, *Information request 51 – Q11*, 27 June 2019, p. 8.

[145] Ergon Energy, *Information request 56 – Q1*, 17 July 2019, p, 11.

[146] Ergon Energy, *Information request 56 – Q6, 10-12*, 17 July 2019, pp. 12-15.

20)[147] and total opex over the 2020–25 regulatory control period by $127.0 million ($2019–20). These adjustments reflecting the 'reform' costs associated with the merger with Energex, comprise:

- the removal of one-off costs identified as “operational improvements", which decreases its base opex by $7.7 million ($2019–20), and its forecast over the 2020–25 regulatory control period by $38.3 million ($2019–20)[148]
- the removal of one-off costs identified as “non-recurring costs”, which decreases its base opex by $10.5 million ($2019–20), and its forecast by $52.4 million ($2019–20) over the 2020–25 regulatory control period[149]
- a reduction for expected merger savings in 2019–20, which decreases its base opex by $7.3 million ($2019–20), and its forecast by $36.3 million ($2019–20) over the 2020–25 regulatory control period.[150]

The proposal did not provide any detail or explanation on what these items consisted of or how these amounts were calculated or derived. Through the information request process, we understand that these are reform costs associated with the merger with Energex and:

- Operational Improvements include
    - redundancy payments, and
    - ‘restructuring’ costs such as consultants hired to advise on restructuring and functional reviews, costs of reskilling and training programs offered to surplus workers, wages paid to surplus workers as required under the EBAs.
- Non-recurring costs include costs of ‘change initiatives’, which are projects which incur upfront costs but generate later savings. Project expenditure in this category is for things like cross functional review and larger organisational wide projects that target the review, redesign and implementation of improvements to our business practices. An example of a barcoding project of warehouse stock was given which involved an upfront costs but has generated ongoing opex savings.
- Merger savings are costs that will be avoided in 2019–20 as a result of the 2016 merger.[151]

We have not included these negative base adjustments in our alternative estimate of opex. As noted in section 6.3, we use a top-down, revealed cost approach to

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[147] Ergon Energy, *1.004 – Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 46-47.

[148] Ergon Energy, *1.004 – Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 46-47; Ergon Energy, *6.008 – Opex forecast – SCS JAN19*, January 2019; AER analysis.

[149] Ergon Energy, *1.004 – Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 46-47; Ergon Energy, *6.008 – Opex forecast – SCS JAN19*, January 2019; AER analysis.

[150] Ergon Energy, *1.004 – Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 46-47; Ergon Energy, *6.008 – Opex forecast – SCS JAN19*, January 2019; AER analysis.

[151] Ergon Energy, *Information request 51 – Q17 and 22*, 27 June 2019, pp.10-11.

determining base opex, where we cross-check the level of efficiency with tools such as benchmarking. Our base opex assessment indicates that base year (unadjusted, estimated) opex is not materially inefficient. Under our preferred approach, we are generally not inclined to made base opex adjustments of this nature in these circumstances.

In addition, through the information request process, we now understand that these are likely to be ongoing and not non-recurring costs. We asked Ergon Energy whether it would continue to incur operational improvement and non-recurring costs beyond 2018-9. Ergon Energy stated that it would.[152] Ergon Energy has been incurring these costs over the current period as a result of the merger to become more efficient, and these costs will continue to be incurred at some level in 2019–20 and over the next regulatory control period. Ergon Energy has also stated that it is an Energy Queensland management decision that these will not be a cost to the customer.[153] The costs incurred to date, and forecast to be incurred over the next regulatory control period, are set out in Table 6.7.

Table 6.7: Ergon Energy actual and forecast negative base adjustments ($ million, 2019–20)

	Current period									Forecast period
	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25
Operational improvements	46.6	15.9	15.0	15.7	10.6	6.7	2.9	1.3	0.0	0.0
Non-recurring costs	3.1	2.2	2.6	4.0	8.1	7.9	7.7	7.5	7.4	7.2
2019–20 merger savings					7.3	7.3	7.3	7.3	7.3	7.3
Total negative adjustments	49.7	18.1	17.6	19.7	25.9	21.9	17.9	16.1	14.6	14.4

Source: Ergon Energy, *Information request 56 – Q6, Q10-12*, 17 July 2019, pp. 12-15; AER analysis.

As can be seen in Table 6.7, Ergon Energy forecasts that the operational improvement, non-recurring costs and 2019–20 merger savings will be $25.9 million ($2019–20) in 2019–20. In 2019–20 the operational improvement costs are lower than those in the previous three years, while the non-recurring costs are higher. We note that Ergon Energy forecasts these costs will continue over the 2020-25 regulatory control period but at lower levels.[154]

This suggests that as Ergon Energy will continue to incur these costs and has stated that its proposal to remove these costs reflected its intention for customers not to bear these costs[155], and given base opex is at a level we do not find to be materially

[152] Ergon Energy, *Information request 51 – Q18*, 27 June 2019, p. 11.
[153] Ergon Energy, *Information request 51 – Q21*, 27 June 2019, p 11.
[154] Ergon Energy, *Information request 56 – Q10*, 17 July 2019, pp. 14-15.
[155] Ergon Energy, *Information request #56 – Q12*, 17 July 2019, p. 15.

inefficient, it is not appropriate to remove them from base opex in our alternative estimate.

However, we note that at the end of our information request process Ergon Energy also noted that some of its statements in relation to the negative base year adjustments have been inconsistent and that it is reconsidering its positions on these adjustments and is yet to form a view on the most appropriate treatment.[156]

As discussed in Attachment 8, we have not included these negative base adjustments in the calculated EBSS carryovers as we do not consider them to reflect realised efficiency gains. This is both because any efficiency gains have not yet been achieved (in 2019–20) but also because the evidence we have suggests the costs associated with the negative base year adjustments will continue to occur. This reduces the EBSS carryover Ergon Energy is entitled to (relative to its proposal) should it decide not to forego its EBSS carryovers as a part of its revised proposal.

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.[157]

Ergon Energy has adopted the approach we have used in our previous determinations to forecasting the rate of change with some variations.

- Price growth: To forecast labour price growth Ergon Energy took the average of the WPI forecast applied by us in our draft decisions for the NSW distributors and that of the consultants BIS Oxford Economics. However, Ergon Energy applied an annual 'unit rate efficiency factor' discount of -0.6 per cent to the average of its labour price growth forecast. It then estimated overall input price growth by calculating the weighted average of its forecast labour and non-labour price growth using our input price weightings.
- Output growth: Ergon Energy used our previous approach to estimate output growth using forecasts of growth in customer numbers, circuit line length, maximum demand and energy throughput weighted using all four benchmarking models. Ergon Energy provided two forecasts of growth of the four outputs: one set in its opex model and a second and more recent set in its regulatory determination RIN.
- Productivity growth: Ergon Energy used a 2.6 per cent annual productivity growth forecast in contrast to our 0.5 per cent forecast.

The rate of change proposed by Ergon Energy decreases its base opex by approximately 1.4 per cent each year. In our alternative estimate, we have included an

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[156] Ergon Energy, *Information request 60 – Q13*, 8 August 2019, p. 6–7.

[157] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 22–24.

average rate of change forecast of 0.4 per cent per year. We explain how we forecast rate of change in our alternative estimate and how it differs from Ergon Energy's forecast below.

Forecast price growth

We included forecast real average annual price growth of 0.3 per cent in developing our alternative opex estimate. This increases opex from the base year by $18.3 million ($2019–20). In contrast, Ergon Energy forecast real annual price growth of 0.2 per cent.[158]

As per our previous approach, 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 forecast growth in the WPI for the Queensland utilities industry from the consultant Deloitte.[159] This is a change in our previous approach of averaging the WPI growth forecasts provided by Deloitte and the consultant engaged by the business and reflects our analysis that over the period 2007 to 2018 Deloitte's real Wage Price Index (WPI) growth forecasts have been more accurate.[160] In contrast, Ergon Energy adopted our previous approach to calculating forecast labour price growth, taking the average of the WPI forecast applied by the AER in its draft decisions for the NSW distributors and of its consultants BIS Oxford Economics.[161]

Ergon Energy applied an annual 'unit rate efficiency factor' of –0.6 per cent to the average of its WPI estimates.[162] Ergon Energy stated this adjustment reflects a management commitment to improve Ergon Energy's program of works by 3 per cent over the 2020–25 regulatory control period.[163] In line with our practice of using an industry-wide approach to forecasting input price growth, rather than a business-specific forecast, we have not included Ergon Energy's 0.6 per cent average annual 'unit rate efficiency' discount to our input price growth forecast.

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158 Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

159 Deloitte Access Economics, *Labour Price Growth Forecasts Prepared for the Australian Energy Regulator*, June 2019, Table 4.3, p. 32; BIS Oxford Economics, *Cost Escalation Forecasts to 2024/25*, June 2018, Fig. 18, p. 33.

160 Stakeholders raised concerns with the labour price growth forecasts in submissions to SA Power Networks' proposal for the 2020-25 revenue determinations. Consequently, we analysed how close the forecasts from both Deloitte and BIS Oxford Economics have been to actual WPI growth over the period 2007 to 2018. We found BIS Oxford Economics persistently over-forecast real WPI growth. In contrast, Deloitte's real WPI growth forecasts have been more accurate. See AER, *Draft decision, SA Power Networks distribution determination 2020−25 Attachment 6 – Operating expenditure September*, 2019, section 6.4.2.1.

161 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 50.

162 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 50.

163 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 50.

To forecast real non-labour price growth, we have applied the forecast change in CPI resulting in zero real non-labour price growth. Ergon Energy has adopted the same approach in their forecast.[164]

We and Ergon Energy 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).[165]

We will have updated labour price growth forecasts from Deloitte that we will use in our final decision.

Forecast output growth

We included forecast average annual output growth of 0.6 per cent in developing our alternative estimate of forecast opex. This increases our base opex by $33.2 million ($2019–20). In contrast, Ergon Energy forecast annual output growth of 1.0 per cent.[166]

Our output growth forecast is a weighted average of the output growth rates forecast using the specification and weights from the four benchmarking models presented in the 2018 Annual Benchmarking Report Data Update.[167] We have forecast our year-on-year output growth by:

- Calculating the output growth rates for four outputs (customer numbers, circuit line length, energy throughput, and maximum demand) based on the most recently available forecasts. We have used Ergon Energy's forecasts of growth in customer numbers, circuit line length, maximum demand and energy throughput from its regulatory determination RIN rather than its opex model.[168] The output growth forecasts provided in Ergon Energy's opex model were calculated in May 2018, while the output growth forecasts provided in Ergon Energy's regulatory determination RIN were calculated in October 2018 and had updated growth assumptions.[169] On this basis, we believe the more recent forecasts provided in the regulatory determination RIN reflect Ergon Energy's best and most up to date expectations of forecast output growth. However, we note that the difference between the output forecasts in Ergon Energy's Reset RIN and those in its opex model results in a lower output growth rate forecast in our alternative forecast. We seek further clarification from Ergon Energy in its revised proposal on the drivers of the differences between the two forecasts.

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164 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 50.

165 We applied Economic Insights' benchmark opex price weightings for labour and non-labour as reflected in our 2017 Annual benchmarking report. For more detail, see: Economic Insights, *Economic benchmarking results for the Australian Energy Regulator's 2017 DNSP benchmarking report*, 31 October 2017, p. 2.

166 Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019.

167 Economic Insights, *2018 Annual Benchmarking Report Data Update*, 8 October 2019.

168 Ergon Energy, *17.053 - 2020-25 Regulatory Determination RIN template*, January 2019.

169 Ergon Energy, *Information Request 22 - Q2*, May 2019, pp. 5-6.

- Calculating four weighted average overall output growth rates using the specification and weights from four benchmarking models presented in our 2018 Annual Benchmarking Report Data Update (see Table 6.8).[170] These models are:
    - Opex multilateral partial factor productivity (MPFP)
    - Cobb Douglas stochastic frontier analysis (SFACD)
    - Cobb Douglas least squares estimation (LSECD)
    - Translog least squares estimation (LSETLG).[171]
- Averaging the four model specific weighted overall output growth rates.

Ergon Energy adopted the same approach described above in its opex forecast but applied the output forecasts in its opex model and the output weights published in our 2018 Annual Benchmarking Report.[172]

We will publish our final 2019 Annual Benchmarking Report in late November 2019. In our final decision, we will update our output growth rate forecasts to reflect the new weightings derived from the benchmarking models with the newest data.

Table 6.8 Output specification and weights derived from economic benchmarking models

Output	MPFP	SFACD	LSECD	LSETLG
Customer numbers	31.0%	71.7%	68.7%	57.7%
Circuit length	29.0%	12.7%	10.8%	11.3%
Ratcheted maximum demand	28.0%	15.6%	20.5%	31.0%
Energy throughput	12.0%			

Source: AER analysis; Economic Insights, *2018 Annual Benchmarking Report Data Update*, 8 October 2019.

Note: Numbers may not add up due to rounding.

Forecast productivity growth

We included forecast productivity growth of 0.5 per cent per year in our alternative estimate. This decreases our alternative estimate by $28.6 million ($2019–20).This is

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170 As noted above, the AER's *2018 Annual Benchmarking Report* results, including the output weights have been updated. These results are available in the Economic Insights, *2018 Annual Benchmarking Report Data Update*, 8 October 2019 at: https://www.aer.gov.au/networks-pipelines/network-performance/annual-benchmarking-report-distribution-and-transmission-2018

171 For example, the output growth rate based on the MPFP model is a weighted average of growth rates 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.

172 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 51-52.

consistent with our final decision in the industry wide review to forecasting opex productivity growth, which we concluded in March 2019.[173] In contrast, Ergon Energy forecast opex productivity growth of 2.6 per cent per year for five years from 2020–21 to 2024–25.[174]

Our productivity growth forecast is a sector-wide productivity forecast that we believe reflects the level of productivity that an efficient distributor engaging in good industry practice should be able to achieve as part of business-as-usual operations. These improvements come from such things as the adoption of new technology, changes to management practices and other factors that contribute to improved productivity within the industry over time.

Ergon Energy's productivity growth forecast is more than necessary to capture improvements in good industry practice over these years, and reflects what Ergon Energy considers it can reasonably achieve.[175]

The CCP14 in its submission welcomed the additional productivity growth offered by the Ergon Energy, but noted the 2.6 per cent per year productivity improvement has not been derived in detail.[176]

In its initial proposal, Ergon Energy states that its higher productivity growth forecast is based on its assessment of being able to achieve its targeted level of opex while continuing to deliver services that meets its regulatory obligations.[177] It notes that it has identified various costs savings that will contribute to achieving the targeted level of opex.

> 'We are proposing a positive productivity saving based on the Energy Queensland top-down management initiative of 10% total indirect cost savings, and other targeted cost reductions, which results in an overall productivity saving of 14% over the 2020-25 regulatory control period, or 2.58% per annum…'[178]
>
> Management has committed to 10% top-down cost savings and 3% improvement in program of works labour costs to further reduce Energy Queensland's indirect costs which will contribute to these productivity savings.[179]

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173 See AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019, available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-our-approach-to-forecasting-opex-productivity-growth-for-electricity-distributors.

174 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 51-52.

175 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, pp. 51-52.

176 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020-25 Regulatory Proposals, May 2019, p.13.*

177 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 51.

178 Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 51.

179 Ergon Energy, *6.003 - Base Year Opex Overview 2020-25*, January, 2019, p. 17.

A business can achieve higher productivity growth than our 0.5 per cent sector-wide forecast by undertaking initiatives that are above and beyond 'business as usual' good industry practices. However, consistent with our sector-wide approach to forecasting productivity outlined above, our alternative forecast includes the 0.5 per cent per year productivity growth number we believe best reflects what an efficient distributor should be able to achieve under business-as-usual operations.

The CCP14 also raised concerns regarding Ergon Energy's reliance on ICT expenditure to underpin the high positive productivity growth forecast.[180]

Ergon Energy has proposed a program of non-recurrent ICT capex, which it states will assist it in achieving its productivity growth forecast.[181] Analysis we have undertaken to assess the non-recurrent ICT program shows that it will generate limited opex benefits in the first half of the 2020–25 regulatory control period, and that the full period opex savings attributed to the ICT program and which have been quantified are relatively small. Of the total $19.8 million in opex savings forecast in the 2020–25 regulatory control period, the majority is forecast for the final two years.[182] We note that these savings account for a relatively small proportion of the total opex savings Ergon Energy would need to achieve to meet its productivity growth forecast.[183] This suggests that Ergon Energy is relying on other measures to achieve the bulk of its targeted opex savings.[184]

6.4.3 Category specific forecasts

We have included a debt raising cost forecast of $18.9 million ($2019–20) in our alternative estimate.

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 forecast of the cost of debt in the rate of return building block. We discuss this in attachment 3 of this draft decision.

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180 CCP14, *Advice to the AER on the Energex and Ergon Energy 2020-25 Regulatory Propo*sals, May 2019, p. 8.

181 See Ergon Energy, *7.007 – ICT Plan,* January 2019.

182 AER, Draft decision, *Ergon Energy Distribution Determination 2020 to 2025*, *Attachment 5: Capital expenditure,* October 2019, p.5-55. Also see: Ergon Energy, *Response to information request 19*, 15 April 2019 and Ergon Energy, *Response to information request 29*, 14 May 2019.

183 *Ergon Energy Distribution Determination 2020 to 2025*, *Attachment 5: Capital expenditure,* October 2019, p. 5-56.

184 In this draft decision, the AER has made a 15 per cent reduction to Ergon Energy's proposed non-recurrent ICT capex forecast (see AER, Draft decision, *Ergon Energy Distribution Determination 2020 to 2025*, *Attachment 5: Capital expenditure,* October 2019, p. 5-57.). We do not foresee that this adjustment will significantly impact the Ergon Energy's productivity growth forecast in its revised regulatory proposal as, as noted above, the non-recurrent ICT program explains a relatively small proportion of the targeted opex savings Ergon Energy is forecasting to achieve to meet its productivity growth forecast.

6.4.4 Assessment of opex factors under NER

In deciding whether or not we are satisfied the service provider's forecast reasonably reflects the 'opex criteria' under the NER, we must have regard to the 'opex factors'.[185]

We attach different weight to different factors when making our decision to best achieve the NEO. This approach has been summarised by the AEMC as follows:[186]

> As mandatory considerations, the AER has an obligation to take the capex and opex factors into account, but this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6.9 summarises how we have taken the opex factors into account in making our draft decision.

Table 6.9 Our consideration of the opex factors

Opex factor	Consideration
The most recent Annual Benchmarking Report that has been published under rule 6.27 and the benchmark opex that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.	There are two elements to this factor. First, we must have regard to our most recent annual benchmarking report. Second, we must have regard to the benchmark opex that would be incurred by an efficient service provider over the forecast 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 opex 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 forecast period. We have estimated an alternative opex estimate and have compared it with Ergon Energy's proposal over the relevant regulatory control period. In doing this we had regard to the information set out in our most recent benchmarking report.
The actual and expected opex of the Distribution Network Service Provider during any proceeding regulatory control periods.	To assess Ergon Energy's opex forecast and develop our alternative estimate, we have used Ergon Energy's estimated opex in 2018–19 as the starting point. We have examined Ergon Energy's historical actual opex and compared it with that of other distribution network services providers.
The extent to which the opex 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.	This factor directs us to have regard to the concerns of consumers, as revealed to us in their engagement with the DNSP. Additionally, this factor requires us to have regard to the extent to which service providers have engaged with consumers in preparing their proposals, such that they are aware of, communicate and factor in the

185 NER, cl. 6.5.6(e).

186 AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, Final Rule Determination, 29 November 2012, p. 115.

Opex factor	Consideration
	needs of consumers. Based on the information provided by Ergon Energy in its proposal and CCP 14's advice, we consider Ergon Energy consulted adequately in developing its opex proposal
The relative prices of capital and operating inputs	We adopted price growth forecasts that account for the relative prices of opex and capex inputs. We generally consider capex/opex trade-offs in considering proposed step changes. 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. Ergon Energy did not propose any step changes as capex/opex trade-offs.
The substitution possibilities between operating and capital expenditure.	Some of our assessment techniques examine opex in isolation—either at the total level or by category. Other techniques consider service providers' overall efficiency, including their capital efficiency. We have relied on several metrics when assessing efficiency to ensure we appropriately capture capex and opex substitutability. In developing our benchmarking models we have had regard to the relationship between capital, opex and outputs.
Whether the opex forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.	The incentive scheme that applied to Ergon Energy's opex in the 2015–20 regulatory control period, the EBSS, was intended to work in conjunction with a revealed cost forecasting approach. We have applied our approved base opex consistently in implementing the EBSS and forecasting Ergon Energy's opex for the 2020-25 regulatory control period.
The extent the opex 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.	Our assessment techniques assess the efficiency of a network service provider's opex and/or capital expenditure at a total level. Provided that we do not find any material inefficiency in a network service provider's total opex in the nominated base year (which we use for our alternative estimate), we generally do not scrutinise a network service provider's related party transactions that may or may not be efficient and prudent. Given that we are satisfied Ergon Energy's base year opex is not materially inefficient, we have not examined any of Ergon Energy's related party arrangements.
Whether the opex forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A1(b).	We have not identified any opex project in the forecast period that should more appropriately be included as a contingent project
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	Ergon Energy stated it accepts the AER's framework and approach position to the demand management incentive scheme and demand management innovation allowance.[187]
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. Ergon Energy did not submit any RIT-D project for its distribution network.

[187] Ergon Energy, *1.004 - Ergon Energy Regulatory Proposal 2020-25*, January 2019, p. 106.

Opex factor	Consideration
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 proposal under clause 6.10.3, is an operating expenditure factor.	We did not identify and notify Ergon Energy of any other opex factor.

Source: AER analysis.

A Operating Environmental Factors

The purpose of this appendix is to explain how we have taken into account Operating Environment Factors (OEFs) in our electricity distribution benchmarking analysis for this draft decision. These are the differences in distribution businesses' operating environments that are not already accounted for in our benchmarking models.

Section A.1 summarises the material OEF adjustments that we apply to Ergon Energy and Energex in this draft decision.

Section A.2 outlines the work undertaken in our recent OEF review and the OEFs that we consider materially affect the relative opex of each distribution business in the NEM.

Section A.3 outlines the issues raised by Ergon Energy and Energex in their proposals in relation to OEFs and the OEFs proposed.

Section A.4 sets out our reasons for using material OEFs for this draft decision and addresses the issues raised by Ergon Energy and Energex.

Section A.5 sets out how we have updated the material OEFs identified for Ergon Energy and Energex. This includes the material OEFs quantified in our recent OEF review as well and the vegetation management OEF which was not quantified

A.1 The OEFs we are applying in this draft decision

Benchmarking broadly refers to the practice of comparing the economic performance of a group of service providers that provide the same service to assess their relative productive efficiency. Distribution businesses do not operate under exactly the same operating environments. When undertaking a benchmarking exercise, it is desirable to take into account how costs driven by different operating conditions can affect the relative expenditures of each distribution business. This ensures we are comparing like with like to the greatest extent possible. By considering these operating conditions, it also helps us determine the extent to which differences in benchmarked performance are affected by factors that are outside the control of each distribution business.

Our economic benchmarking techniques account for key differences in operating environments through the explanatory variables (e.g. size and density of networks, degree of underground cabling) in the various models. However, our benchmarking models do not directly account for differences in legislative or regulatory obligations, climate and geography. These may materially affect the operating costs in different jurisdictions and impact the relative efficiency of each distribution business as determined by our benchmarking models. We call these differences in operating environments not already accounted for in our benchmarking models operating environment factors or OEFs.

Given this, we incorporate these OEFs in our benchmarking analysis. This enables us to assess the efficiency of a distribution business's operations on a like for like basis to inform our assessment of whether its base year opex is efficient or materially inefficient. We do this by using the OEFs to adjust the benchmark comparison point to account for the operating environment of the distribution business we are assessing (see Box 6.1 in section 0 of Attachment 6). This adjusted comparison point is then compared to the business's benchmark efficiency score (from the benchmarking models) allowing us to account for potential cost differences due to OEFs between the business and the benchmark comparison firms. More detail on the mechanics of our approach is contained in past decisions.[188]

Table A6.1 and Table A6.2 show the material OEFs relevant to Ergon Energy and Energex and the OEF adjustments we have applied in this draft decision. The OEF adjustments are positive, which means that an efficient business in Ergon Energy and Energex's operating environment would require more opex than the benchmark comparison firms (12.6 per cent for Ergon Energy and 5.8 per cent for Energex). This reflects that these businesses face a relative cost disadvantage due to their operating environment. We have applied these aggregate OEFs for the longer and shorter benchmarking periods in adjusting the benchmark comparison point in our benchmarking analysis in Attachment 6.[189]

Table A6.1 Aggregate OEFs adjustment, 2006–17 period (per cent)

	Energex	Ergon Energy
Cyclones	0.00	5.24
Sub–transmission	1.05	5.91
Taxes and levies	1.73	0.91
Termite exposure	0.33	1.10
Vegetation management (Division of responsibility)	2.71	2.79
Vegetation management (Bushfire risk)	0.00	-3.36
Total	5.83	12.61

Source: AER, *Annual Benchmarking Report, Electricity distribution network service providers,* November 2018; Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking,* August 2018; AER analysis.

188 See AER, *Preliminary Decision, Ergon Energy determination 2015-20, Attachment 7 – Operating Expenditure*, April 2015, pp. 93–138; AER, *Draft Decision, Ausgrid Distribution determination 2019-24, Attachment 6 - Operating Expenditure*, November 2018, pp. 31–33; AER, *Draft Decision, Endeavour Energy Distribution determination 2019-24, Attachment 6 - Operating Expenditure*, November 2018, pp. 27–29.

189 The vegetation management (mainly bushfire risk) OEF adjustments are different across the two benchmarking periods, which is linked to a change in regulatory obligations and incremental costs in 2010. In contrast, for the other material OEFs we have applied the same adjustments over the two periods as we have assumed that the underlying operating environment conditions associated with these OEFs remain consistent over time.

Table A6.2 Aggregate OEFs adjustment, 2012–17 period (per cent)

	Energex	Ergon Energy
Cyclones	0.00	5.24
Sub–transmission	1.05	5.91
Taxes and levies	1.73	0.91
Termite exposure	0.33	1.10
Vegetation management (Division of responsibility)	2.58	2.56
Vegetation management (Bushfire risk)	0.00	-5.75
Total	5.70	9.98

Source: AER, *Annual Benchmarking Report, Electricity distribution network service providers,* November 2018; Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking,* August 2018; AER analysis.

These material OEFs were identified in our 2018 Annual Economic Benchmarking Report, which was informed by our recent OEF review and the expert report prepared by Sapere Research Group and Merz Consulting (Sapere–Merz). As explained below, we have quantified the OEF adjustments in two stages:

- We applied the adjustments calculated by Sapere–Merz for cyclones, sub–transmission taxes and levies, with updates to reflect the benchmark comparison firms in the 2018 Annual Benchmarking Report Data Update.[190]
- We calculated two vegetation management OEFs for the purpose of this draft decision. Vegetation management was identified in the Sapere–Merz report as being likely to drive material differences in efficient vegetation opex, but these differences were not quantified.[191]

The material OEFs we have applied in this draft decision represents a change from the approach used in our April 2015 decision for Ergon Energy and Energex (and subsequent draft decisions in November 2018 for NSW distribution businesses and Evoenergy). In particular, this draft decision does not account for material and immaterial OEFs. In making this decision to use material OEFs we have taken into account that:

- Benchmarking is a top–down approach to assessing the relative efficiency of distribution networks in the NEM, which lends itself to taking into account material differences between distribution networks rather than all differences. While previous decisions considered material and immaterial differences, this was in the

190 Economic Insights, *2018 Annual Benchmarking Report Data Update*, 8 October 2019.

191 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking,* August 2018, p. 65.

context of the initial application of benchmarking and the information available to us at the time. This led to a more conservative and cautious approach to benchmarking and the calculation of OEFs.

- We have now undertaken the OEF review process that included industry–wide consultation and the development of the Sapere–Merz report in relation to material OEFs. This represents an incremental improvement from our previous analysis and decisions that we consider should be applied in our draft decision, noting that there are still areas for improvement.
- We have retained the benchmark comparison score (0.75) from our previous analysis and decisions, which we consider remains relatively conservative, providing a margin to account for any residual data issues.

As part of our ongoing development program for OEFs, we will continue to incrementally refine the OEFs including improving the datasets used to quantify individual material OEFs, and considering how the identification and quantification of OEFs may need to change over time to reflect changes in the operating environment and the efficient costs of each OEF.

A.2 Our recent OEF development work

Our 2015 decisions for Ergon Energy and Energex identified and quantified ten material OEFs and also the collective impact of nineteen immaterial OEFs.[192] We came to this conclusion after assessing over sixty different OEFs that we, distribution businesses, and other stakeholders identified in the process of making our decision and in response to our 2014 draft benchmarking report. For the 2015 decisions we included OEFs that individually may have had an immaterial impact on opex, but their combined effect may have been material.

In 2017 and 2018 we undertook an OEF review of the material factors affecting the relative opex of each distribution business in the NEM. The review included analysis undertaken for us by engineering and economic consultants Sapere–Merz. In its report prepared as a part of our OEF review, Sapere–Merz provided us with expert advice on the material OEFs driving apparent differences in estimated productivity and operating efficiency between the distribution businesses in the NEM. Sapere–Merz's advice expanded on, and refined, our previous analysis of OEFs in our 2015 opex decisions for Ergon Energy and Energex (as well as the NSW distribution businesses and

[192] AER, *Final decision, Ergon Energy determination 2015−16 to 2019−20, Attachment 7 – Operating expenditure*, October 2015, pp. 53-69; AER, *Preliminary decision, Ergon Energy determination 2015−16 to 2019−20, Attachment 7 – Operating expenditure*, April 2015, pp. 164–260; AER, *Preliminary decision, Energex determination 2015−16 to 2019−20, Attachment 7 – Operating expenditure*, April 2015, pp. 156–251.

Evoenergy).[193] Sapere–Merz consulted with the electricity distribution industry in identifying these factors (this is discussed further below).[194]

Sapere–Merz identified five material OEFs that are relevant to Ergon Energy and Energex, quantifying all except one – the vegetation management OEF:[195]

- The higher operating costs of maintaining sub–transmission assets (including the licence conditions)
- Vegetation management requirements[196]
- Jurisdictional taxes and levies
- The costs of planning for, and responding to, cyclones (Ergon Energy only)
- Termite exposure.

The reasoning and process that we, and Sapere–Merz, went through to identify these OEFs is set out in detail in the Sapere–Merz's report and summarised in our 2018 Annual Benchmarking Report. [197]

The Sapere–Merz report noted some limitations of its study, including further work required on the quantification of vegetation management as an ongoing priority.[198] Our 2018 Annual Benchmarking Report noted that we intended to consult further with the distribution industry to further refine the assessment and quantification of OEFs.[199]

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193 See for example, AER, *Final decision, Ausgrid distribution determination 2015−16 to 2018−19, Attachment 7 – Operating expenditure*, April 2015, Section A.6, pp. 172–269.

194 The Sapere-Merz report includes more detail about the information and data it used, our consultation with the distribution industry, and the method for identifying and quantifying these OEFs. See Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, pp. 20–21.

195 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. xii-xiii. Sapere-Merz identified other OEFs that are not relevant to Ergon Energy or Energex, including backyard reticulation that is only applicable to Evoenergy.

196 This was considered by Sapere-Merz as likely to be a material OEF. However, Sapere-Merz did not quantify this OEF. See Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. ix. Section A.5 below outlines how we have calculated an OEF adjustment in relation to vegetation management for this draft decision.

197 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018; AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2018, pp. 23–29.

198 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. xiv.

199 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2018, pp. 28–29.

A.3 OEFs proposed by Ergon Energy and Energex

Ergon Energy and Energex's proposals included benchmarking and category analysis in support of the efficiency of their estimated base year opex.[200] This benchmarking analysis, prepared by Frontier Economics, considered three sets of OEFs:

- the AER's 2015 decision OEF adjustments, including immaterial OEFs
- the AER's 2015 decision OEF adjustments, excluding immaterial OEFs
- the Sapere–Merz OEF adjustments.

The Frontier Economics report also included commentary on the application of OEFs to benchmarking of Ergon Energy and Energex.[201] In its report, Frontier Economics outlined what it considered were a number of problems with the Sapere–Merz report and its calculations. The key issues identified by Frontier Economics were:[202]

- The Sapere–Merz report only quantifies five OEFs out of over sixty OEFs identified by the AER in its 2015 assessment of potential OEF candidates. It states that this likely significantly understates the OEF adjustments necessary to explain differences in the operating environments of different distribution businesses in the NEM.
- That Sapere–Merz and the AER subjectively assess the materiality of OEFs, prior to them being quantified. It states that an assessment of materiality can only be made after the OEF is quantified.
- That poor quality (or lack) of data collected on OEFs to date limits the extent to which any assessment of OEFs can be effectively implemented at present. It suggested that there is a need for extensive further consultation and data collection to enhance the quantification of OEFs.
- That Sapere–Merz excluded consideration of the immaterial OEFs and that these were outside the terms of reference.
- That our OEF approach is confounded by accounting for OEFs only after the raw efficiency scores of our benchmarking models have been estimated, known as the ex–post adjustment approach. It argued that the true relationship between the distribution businesses' costs and cost drivers will be distorted by the inclusion of non–comparable opex data.

In section 4 of its report, Frontier Economics also put forward additional possible OEFs for Ergon Energy and Energex, and makes an assessment of whether and to what

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200 Frontier Economics, *AER Benchmarking - A report prepared for Energy Queensland*, 15 January 2019; Ergon Energy, *6.003 – Base Year Opex Overview 2020,* 25 January 2019, pp. 20–34.

201 Frontier Economics, *AER Operating Environment Factors (OEFs) - A Report Prepared for Energy Queensland*, 15 January 2019.

202 Frontier Economics, *AER Operating Environment Factors (OEFs) - A Report Prepared for Energy Queensland*, 15 January 2019, p. 23.

extent these OEFs have been considered by the AER and Sapere–Merz.[203] Based on Frontier Economics' report, Ergon Energy and Energex's proposals focused on a subset of material OEFs that it considered are particularly relevant to category analysis benchmarking of Ergon Energy and Energex. These were: customer density, route line length, overhead lines proportion of total network, exposure to extreme weather and storms, sub–transmission, and solar PV uptake.

A.4 Why we have moved to the use of material OEFs

The use of material OEFs in this draft decision represents a change from the approach used in our April 2015 decision for Ergon Energy and Energex (and subsequent decisions in November 2018 for NSW distribution businesses and Evoenergy), which applied OEF adjustments that accounted for both material and immaterial OEFs.

As noted above, for the April 2015 decisions we included OEFs that individually may have had an immaterial impact on opex, but their combined effect may have been material. The decision to include immaterial OEFs was part of a deliberate decision to adopt a cautious approach in the context of our first use of benchmarking and a more limited information set.

The change in approach, and the use of material OEFs for this draft decision, is based on our assessment that, based on the best available information, the continued application of the immaterial OEFs now represents an overly conservative estimate of the impact of OEFs on differences in businesses' costs. The use of immaterial OEFs likely overestimates the magnitude of the differences between Ergon Energy and Energex and the comparison point firms when used in the context of identifying material inefficiency.

Our reasons for deciding to apply the material OEFs as outlined in Sapere–Merz's report in our benchmarking analysis for this draft decision include:

- Benchmarking is a top–down approach to assessing the relative efficiency of distribution businesses in the NEM. In our regulatory decisions, we have used benchmarking to identify distribution businesses that are materially inefficient. This approach of benchmarking lends itself to taking into account material differences between distribution businesses rather than all differences. While previous 2015 decisions considered material and immaterial differences, this was in the context of the initial application of benchmarking and the information available to us at the time. This led to a more conservative and cautious approach to benchmarking and the calculation of OEFs.
- We have now undertaken the OEF review process that included industry–wide consultation and the development of the Sapere–Merz report in relation to material OEFs. This represents an incremental improvement from our previous analysis and

[203] Frontier Economics, *AER Operating Environment Factors (OEFs) - A Report Prepared for Energy Queensland*, 15 January 2019, pp. 25–35.

decisions that we consider should be applied in our draft decision, noting that there are still ongoing areas for improvement.

- We have retained the benchmark comparison score (0.75) from our previous analysis and decisions, which we consider remains relatively conservative, providing a margin to account for any residual data issues. This is in the context where we now use multiple benchmarking models to better account for differences between distribution businesses (a number of different production functions and efficiency estimation techniques are therefore taken into account). As a result, we have further comfort that we no longer need to be as cautious and conservative as we initially were in our quantification of OEFs.

We address these points in more detail below.

Examining material differences in OEFs

Benchmarking is an inherently top–down method of measuring relative efficiency. When the AEMC added the requirement for the AER to publish annual benchmarking results, it stated:

> The intention of a benchmarking assessment is not to normalise for every possible difference in networks. Rather, benchmarking provides a high level overview taking into account certain exogenous factors. It is then used as a comparative tool to inform assessments about the relative overall efficiency of proposed expenditure. [204]

In our 2015 decisions for Ergon Energy and Energex, our OEF adjustments included a range of immaterial OEFs. However, as we explained in our 2015 decision, our approach to OEFs was informed by our initial conservative approach to applying benchmarking and the information available to us at the time:[205]

> We consider that this is an appropriately conservative approach. We note that the AEMC has stated that the purpose of benchmarking is not to normalise for every possible difference between networks. However, after considering the impact of more than 60 proposed OEFs, in addition to adjusting for 10 material OEFs, we have provided an adjustment for the collective effect of 19 immaterial OEFs. We consider it is appropriate to take this additional step in our benchmarking analysis given this is the first time we have applied benchmarking and the information on OEFs available to us at this stage. We also note that we have provided positive adjustments where the direction of advantage for immaterial factors is unclear. This is to allow service providers to recoup at least efficient costs incurred as a result of those immaterial OEFs, consistent with the revenue and pricing principles in the NEL. In future, as our

[204] AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, November 2012, pp. 107–108.

[205] AER, *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 7 – Operating Expenditure*, April 2015 pp. 170–171.

> information set improves we may reconsider our approach to immaterial OEFs. [emphasis added]

In addition to accounting for immaterial OEFs, our approach to benchmarking previously included adopting a benchmark comparison point that was the lowest of the efficiency scores in the top quartile of possible benchmark efficiency scores, rather than the most efficient distribution businesses in the NEM.

The OEF review process and improved information

We now have better information to support the identification and quantification of the key material differences in operating environments in the NEM. The OEF review we undertook over 2017 and 2018, which included the development of the Sapere–Merz report in relation to material OEFs, represents an improvement in our information set.

The OEF review was a consultation process that involved the whole industry:

- This review process included industry–wide consultation that provided distribution businesses, and other stakeholders, multiple opportunities to provide their views and submissions that were then fully considered. The process was supported by the use of the consultant, Sapere–Merz, who brought industry and engineering knowledge and expertise in relation to the electricity distribution sector.
- The review involved a rigorous filtering process to establish the material OEFs, considering both those previously identified by the AER along with those suggested by the distribution businesses.
- The review identified improved approaches and methodologies for quantifying material OEFs, along with some additional data to support the quantification.

We note that while the Sapere–Merz report only quantifies five OEFs for Ergon Energy and Energex, in the process of its review it considered the full range of OEFs previously examined by the considered by the AER. As set out in Sapere–Merz's report:[206]

> … the principal focus of the review is the most material of over 60 operating environment factors driving apparent differences in estimated productivity and operating efficiency between the distribution networks in the NEM, now considered uniformly across all DNSPs.
>
> Out of a large set of candidate OEFs identified by DNSPs (see Appendix 4), six potential OEF candidates are identified as having a higher chance of meeting the information challenge described in Section 2.2.2, and hence potential to completely address the AER's three OEF criteria.

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206 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, Section 4, p. 1.

In this context, we consider that the OEFs included in the Sapere–Merz report represents an incremental improvement from our previous analysis and decisions that we consider should be applied in our draft decision.

The Frontier Economics report identified additional OEFs relevant to Ergon Energy and Energex that the Sapere–Merz report did not quantify. These were:

- Diversity of weather and extreme weather. These factors are partly covered by the OEF for cyclones for Ergon Energy, and we note that Sapere–Merz considered this in detail and formed the view that these factors are best characterised as high impact low probability (HILP) events, and that HILP events by their nature do have an impact on Economic Insights models.[207]
- Division of vegetation management responsibility and bushfire risk. Our approach to quantifying these factors is covered in section A.5 below.
- Network configuration. This factor is partly covered by the OEF for sub–transmission. Network topology was considered in detail by the Sapere–Merz report, which found that while this is an exogenous factor, its materiality was not established on the basis of the available data.[208]
- Network scale and accessibility. The network scale factor is largely covered by the explanatory variables in the econometric models, including the combination of circuit line length and customer numbers. Sapere–Merz considered aspects of network accessibility in examining network topology and topography, but was not able to draw any conclusions about whether it was a material OEF.[209]

The Sapere–Merz report acknowledged the findings and conclusions in its final report are based on the best currently available information, and on a number of assumptions.[210] It also suggested potential improvements to our data sources that we should consider as part of our continuous improvement of economic benchmarking and quantifying the impact of material OEFs. Therefore, the approach to quantifying OEFs is one of incremental improvement, alongside the continual development of our benchmarking toolkit.

Conservative approach to benchmarking

We continue to adopt a relatively conservative approach to benchmarking. As set out in Attachment 6, our benchmarking analysis compares Ergon Energy and Energex's efficiency scores against a benchmark comparison score of 0.75 (after adjustment for

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207 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, pp. 41–42.

208 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, pp. 3–12.

209 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, pp. section 4.2, p. 7.

210 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, Executive summary, pp. vii–xvi.

OEFs). The benchmark comparison score reflects the upper quartile of possible efficiency scores by distribution businesses, and reflects our conservative approach to setting a benchmark comparison point and identifying whether Ergon Energy and Energex are materially inefficient. We consider this relatively conservative benchmark comparison point provides an appropriate margin to account for any residual data issues.

We are also making use of multiple benchmarking models rather than the single econometric model we relied upon in our April 2015 decision. The use of multiple models better accounts for differences between distribution businesses because it uses a number of different production functions and efficiency estimation techniques. This use of multiple benchmarking models to identify material inefficiency gives us further comfort that we no longer need to be as conservative in our quantification of OEFs.

Finally, we note Frontier Economics' submission that it is preferable to adjust for OEFs within the benchmarking modelling itself and derive efficiency scores that reflect the relationship between distribution businesses' costs and all cost drivers including OEFs. Our current approach is to account for OEFs after the first stage of the benchmarking analysis (which Frontier refers to as 'ex post adjustment').

There are primarily two different ways that OEFs could be incorporated directly within the benchmarking modelling:

- Include additional output or operating environment variables in the benchmarking models.
- Exclude the costs associated with the OEFs from the opex data. This would require information from each distributor about the incremental costs associated with each OEF.

However, these would likely be difficult and time consuming to develop and require relatively significant further engagement with industry and additional data collection, including extensive recasting of data and model testing. In the meantime, we maintain that our post–modelling approach to accounting for OEFs is a reasonable and practical approach in the context of a top–down approach to benchmarking and opex assessment more broadly.

A.5 Updating the material OEFs for Ergon Energy and Energex

Updating the material OEFs previously quantified by Sapere Merz

For this draft decision, we have updated the four material OEFs that Sapere–Merz quantified in its 2018 report to reflect the benchmark comparison firms in the 2018 Annual Benchmarking Report Data Update.[211]

The Sapere–Merz 2018 report calculated OEF adjustments for Ergon Energy and Energex relative to the benchmark comparison firms over the 2006–15 period as estimated by our SFA Cobb–Douglas model. These benchmark comparison firms were CitiPower, Powercor, United Energy, SA Power Networks and AusNet Services. In this draft decision, we have relied on the benchmark comparison firms over the 2006–17 and 2012–17 periods that have an average efficiency score of 0.75 and above, as estimated across all of our econometric models. The benchmark comparison firms over both time periods are CitiPower, Powercor, United Energy, and SA Power Networks (and no longer include AusNet Services).[212] Using this approach to determine the material OEF adjustments ensures greater consistency with our benchmarking comparison point.

Table A6.3 sets out the updated percentage adjustments (that are made to the benchmark comparison point) of the four OEFs quantified by Sapere–Merz.

Table A6.3 Updated Sapere–Merz material OEF adjustments for Ergon Energy and Energex (per cent)

	Energex	Ergon Energy
Cyclones	0.00	5.24
Sub–transmission	1.05	5.91
Taxes and levies	1.73	0.91
Termite exposure	0.33	1.10
Total	3.12	13.17

Source: Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018; AER, *Annual Benchmarking Report, Electricity distribution network service providers,* November 2018. AER analysis. The

211 We will update our OEF calculations summary spreadsheet for the final decision to reflect the results from the 2019 Annual Benchmarking Report and in particular to use the period average opex over the benchmarking periods (instead of the 2015 historical opex used by Sapere-Merz).

212 See our *2018 Annual Benchmarking Report* and the *2018 Annual Benchmarking Report Data Update* for more detail, including the relative efficiency scores of these businesses.

calculations for these adjustments are shown in the OEF calculations summary spreadsheet included on our website with this draft decision.

As noted above, the OEF adjustments in Table 3 mean that an efficient business in Ergon Energy's operating environment would require more opex than the benchmark comparison firms (13.2 per cent more opex for Ergon Energy and 3.1 per cent more opex for Energex). This reflects that these businesses face a relative cost disadvantage due to their operating environment. In practice, we account for these positive OEFs by reducing the benchmark comparison point by the OEF percentage. For the purpose of the draft decision we have applied the same Sapere-Merz material OEFs over the 2006–17 and 2012–17 benchmarking periods. This is because we have assumed that the underlying operating environment conditions associated with these OEFs remains consistent over time. This contrasts with our bushfire risk OEF (see below) which is linked to a change in regulatory obligations and incremental costs in 2010. This means that our bushfire risk OEF will lead to a different OEF adjustment over 2006–17 and 2012–17 benchmarking periods.

Calculating the vegetation management OEFs

Vegetation management was identified by Sapere–Merz as being likely to drive material differences in efficient vegetation opex during our OEF review, but it was not quantified as an OEF.[213] To quantify a vegetation management OEF for this draft decision we must calculate whether Energex and Ergon Energy face a relative cost advantage or disadvantage in maintaining vegetation within its network, compared to the benchmark efficient distribution businesses in the NEM.

In this section we have calculated a vegetation management OEF as the summation of two factors:

- Differences in vegetation management obligations relating to managing bushfire risk.
- Differences in the division of responsibility with local councils, road authorities and land owners in managing vegetation.

This approach is similar to the approach we adopted in our 2015 reset final decisions for Energex and Ergon Energy, with updated information where appropriate.

Background

Distribution businesses are obliged to ensure the integrity and safety of overhead lines by maintaining adequate clearances from any vegetation that could interfere with lines or supports. Several factors drive the costs of managing vegetation that are beyond the control of distribution businesses:

213 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, pp. 61, 65.

- Different climates and geography affect vegetation density and growth rates, which may affect vegetation management costs per overhead line kilometre and the duration of time until subsequent vegetation management is again required.
- State governments, through enacting statutes, decide whether to impose bushfire safety regulations on distribution businesses and how to divide responsibility for vegetation management between distribution businesses and other parties.
- Predominantly rural distribution businesses may be exposed to a greater proportion of lines requiring active vegetation management than urban distribution businesses.

Vegetation management costs account for between 10 and 20 per cent of total opex for most distribution businesses. Hence, differences in vegetation management costs potentially have a material impact on the relative opex efficiency of distribution businesses.[214]

Our economic benchmarking models largely account for differences in vegetation management opex between distribution businesses. This is through the inclusion of a circuit line length output variable. Overhead line length is a potential driver for vegetation management costs, as vegetation management obligations relate to maintaining clearance between overhead lines and surrounding vegetation. However, Sapere–Merz’s analysis of the Category Analysis RINs and economic benchmarking data found that the overhead line variable does not fully explain variations in regulatory obligations, and in vegetation density and growth rates across times and between different locations. [215]

Sapere–Merz's report identified a number of information sources and methodologies that could be used to quantify the effect of regulatory obligations and vegetation density. Sapere–Merz’s preferred method was to calculate the total combined effect of these two factors on vegetation management costs. However, it could not quantify these factors based on currently available data. Its report provides some recommendations and options for quantifying these factors in the future and the additional data required for this assessment.[216]

Sapere–Merz’s report noted that a vegetation management OEF could be estimated by the AER on a case by case basis until such time as a systematic quantification is implemented.[217]

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214 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 65.

215 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 62.

216 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, pp. 65–68.

217 Sapere Research Group and Merz Consulting, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, August 2018, p. 66.

At this stage, given we have not yet undertaken further work to systematically quantify the impact, the best available information to estimate a vegetation management OEF is our 2015 opex decisions for Ergon Energy and Energex. In these decisions, we quantified two vegetation management–related OEFs for Ergon Energy and Energex:

- Bushfire risk — the differences in opex between distribution businesses due to differences in bushfire risk between Queensland and the comparison networks, which are located in Victoria and South Australia, and associated differences in the regulatory obligations for clearing vegetation.[218]
- Division of responsibility — the differences in opex between distribution businesses due to differences in who is responsible for managing vegetation clearance in each network, such as the division of responsibility between the networks, local councils, road authorities and landowners.[219]

These two issues are consistent with one of the key factors identified by Sapere–Merz as a driver of the costs of managing vegetation that are outside the control of distribution businesses (the effect of different regulatory obligations). As such, they quantify the impact of some of the material drivers of differences in Ergon Energy and Energex's vegetation management costs relative to other distribution businesses.

These factors do not directly quantify the impact of differences in vegetation density and growth rates between Ergon Energy and Energex and the other distribution businesses, which was also identified by Sapere–Merz as a driver of differences in vegetation management costs. However, through our assessment of differences in bushfire risk, which shows that higher vegetation density generally results in higher bushfire risk (see below), this is taken into account at a high level.

Therefore, we consider that our 2015 approach to vegetation management provides a reasonable approximation for a vegetation management OEF, in the absence of a more systematic quantification.

Below we describe our examination of these two factors and how we have updated the vegetation management OEF adjustment calculation for this draft decision.

Bushfire risk

In our 2015 opex final decision, we concluded that Ergon Energy faced a cost advantage in managing bushfire risk compared to the benchmark comparator

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218 AER, *Preliminary decision, Ergon Energy determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, April 2015, pp. 200–209; AER, *Preliminary decision, Energex determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, April 2015, pp. 191–200.

219 AER, *Preliminary decision, Ergon Energy determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, April 2015, pp. 225–228; AER*, Preliminary decision, Energex determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, April 2015, pp. 216–219.

distribution businesses and therefore faced relatively lower opex.[220] Accordingly, we estimated a negative OEF for bushfire risk, which had the effect of increasing the benchmark comparison point for Ergon Energy. In summary, the reasons for this finding were:

- Lower bushfire risk: Queensland, and Ergon Energy's service area in particular, did not face the same level of bushfire risk as the benchmark comparison distribution businesses in Victoria (in particular Powercor, AusNet Services and United Energy that operate in high bushfire risk areas). This was based on historical and existing information about the probability and severity of bushfires in the relevant service areas, which gave an indication of the underlying environmental bushfire risk faced by the service providers in each state.[221] Our analysis was informed by:
    - maps of potential bushfire zones and bushfire intensity in different regions of Australia
    - instances of significant bushfires in Queensland compared to Victoria
    - past and forecast economic costs of bushfires, and
    - statements from Ergon Energy about its relative bushfire risk.
- Lower bushfire mitigation obligations: The vegetation management obligations imposed by the Queensland government on the Queensland distribution businesses have not been as strict as the Victorian distribution businesses over the benchmarking period. We examined the relevant legislation governing vegetation management requirements, and the more stringent bushfire risk management obligations that applied to the Victorian distribution businesses following the 2010 Black Saturday bushfires.
- Duty of care is proportionate to the risk: a prudent and efficient distribution business would only exercise its duty of care in the context of the risks it faces. Ergon Energy did not face the same underlying bushfire risk as Victoria, and so we concluded that one would expect that it would require less expenditure per km of overhead lines than the Victorian distribution businesses to mitigate these risks (holding all else equal).
- Vegetation density is low in Ergon Energy's network: Vegetation density maps from the Bureau of Meteorology showed that vegetation density in Ergon Energy's network is low and comparable to the lower bushfire risk areas in north west Victoria.

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220 AER, *Final decision, Ergon Energy determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, October 2015, pp. 64–68. In the Energex decision we concluded that the vegetation density in Energex's network meant it was uncertain whether it faced a cost advantage. See AER, *Preliminary decision, Energex determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, April 2015, pp. 191–200.

221 For more detail see AER, *Final decision, Ergon Energy determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, October 2015, pp. 64–68; AER, *Preliminary decision, Ergon Energy determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, April 2015, pp. 201–204.

More detailed information about our assessment can be found in our 2015 opex decision.[222]

While we found that Ergon Energy did not face the same bushfire risk and duty of care as the Victorian distribution businesses, we did not reach the same conclusion for Energex. In particular, we found that Energex's rural service area networks faced higher vegetation density than Ergon Energy and comparable to some of the higher bushfire risk parts of Victoria.[223] We concluded that this higher vegetation density may offset some of the effect of the more stringent bushfire regulations in Victoria. Ergon Energy did not appear to have any material offsetting factors.

On this basis, our 2015 decisions calculated a material bushfire risk OEF for Ergon Energy by quantifying the incremental effects of new regulations faced by Victorian distribution businesses following the 2010 Black Saturday bushfires. The increased opex as a result of the new regulations was used as a proxy for the differences in the costs related to managing bushfire risk between Queensland and Victoria. We did not quantify a material OEF for bushfire risk for Energex, and instead treated it as an immaterial OEF.[224]

Establishing that Ergon Energy retains a cost advantage in relation to bushfire risk

To apply our 2015 bushfire risk OEF approach to Ergon Energy and Energex in our draft decision, we have considered:

- The changes in Ergon Energy and Energex's vegetation management opex over time and how these compare to the changes in the vegetation management opex of the Victorian distribution businesses, who are the reference firms for the comparison point
- Our assessment of the relative bushfire risks conducted in 2015
- Our assessment of the differences in bushfire regulations and duty of care conducted in 2015.

Figure A6.1 shows that Ergon Energy and Energex's vegetation management opex has broadly decreased since 2013. In its submission to the AER's 2018 Annual Benchmarking Report, Ergon Energy and Energex stated that they had both achieved significant vegetation management efficiencies in recent years through changes to its

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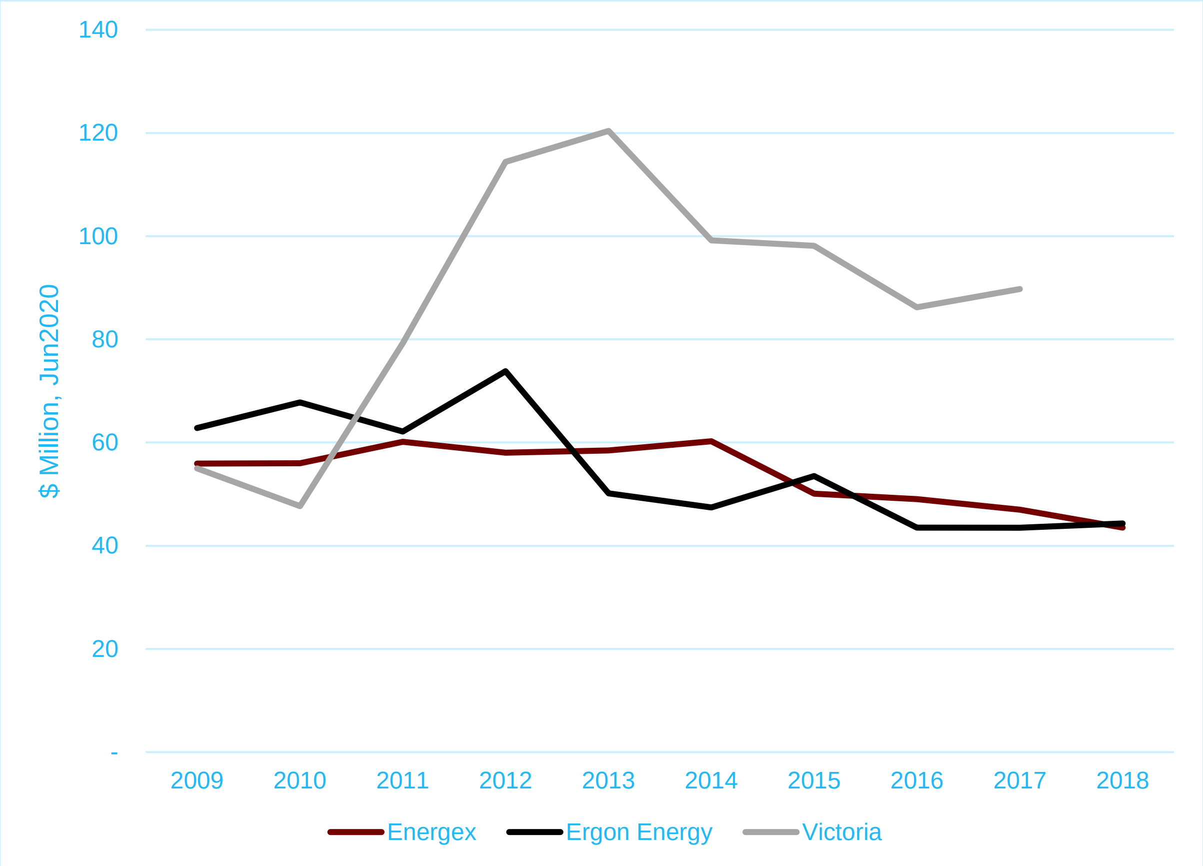
[222] AER, *Final decision, Ergon Energy determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, October 2015 pp. 64–68.

[223] AER, Preliminary decision, *Energex determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, April 2015, pp. 191–200; AER, *Preliminary decision, Ergon Energy determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, April 2015, pp. 200–209.

[224] AER, *Preliminary decision, Ergon Energy determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, April 2015, p. 208.

strategies, processes and contractual arrangements.[225] Furthermore, the difference in Ergon Energy's and Energex's vegetation management costs relative to the Victorian distribution businesses has been broadly consistent since 2012.

Figure A6.1 Annual vegetation management opex between 2009 and 2018 – Ergon Energy, Energex and the combined Victorian distribution businesses



Source: Category Analysis RINs; AER analysis

Note: The Victorian distribution businesses are AusNet Services, CitiPower, Jemena, Powercor and United Energy.

We would expect any increase in Ergon Energy or Energex's bushfire risk or vegetation management responsibilities would materially change its vegetation management costs over the benchmark period. For example, if Energex and Ergon Energy adopted the same type of bushfire mitigation activities introduced by the Victorian regulations in 2010, we would expect a significant increase in their vegetation management opex. However, Figure 1 suggests Ergon Energy and Energex's

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[225] Energy Queensland, *Annual Benchmarking Report: Electricity distribution network service providers, Joint response to the Australian Energy Regulator's draft report,* 19 October 2018, p. 5.

vegetation management opex has decreased since 2010. This lends support to relying upon our 2015 approach in relation to the OEF for relative bushfire risks and differences in bushfire regulations and duty of care. We have also not received any new information from Ergon Energy and Energex about its relative bushfire risk and responsibilities since our 2015 decision, such as in its submissions to our OEF review and the Frontier Economics report.

In its revised proposal, Ergon Energy and Energex are encouraged to provide information and evidence if their vegetation management obligations and practices have changed since 2013 and this has led to any material changes in its vegetation management opex. As part of our ongoing development program for OEFs, we intend to collect and examine more recent information about relative bushfire risk and any changes in responsibilities and practices around vegetation management.

Quantifying the bushfire risk component of the OEF for Ergon Energy for the draft decision

Our 2015 decisions quantified the differences in the costs related to managing bushfire risk between Queensland and Victoria by examining the increase in costs faced by Victorian distribution businesses following the 2010 Black Saturday bushfires. The increase in costs faced by the Victorian distribution businesses reflected the incremental difference in bushfire risk and responsibilities between the Victorian benchmark firms and Ergon Energy. The quantification was based on forecast costs of step changes and opex pass throughs for the Victorian distribution businesses that we approved for the 2011–15 period.

In Victoria for the 2011–2015 period, the increase in regulatory obligations related to bushfires was forecast to account for 9 per cent of total opex. Although the increase in opex associated with the new bushfire risk mitigation obligations for the Victorian distribution businesses was quite large, the new obligations came into effect at various times from 2010. In our 2015 decisions for Ergon Energy, we relied upon benchmarking results that covered the 2006 to 2013 period. As a result, the incremental bushfire mitigation costs in Victoria only affected the last three years of the benchmarking period. This reduced the effect of the impact of the change in regulations on the benchmarking results.

We have continued to rely on these forecasts costs to quantify the cost of the OEF for bushfire risks. We note that we have also used this information in our recent opex productivity review final decision for distribution businesses. We have relied on this previous forecast information because we do not currently have information on the actual costs incurred by the Victorian distribution businesses in relation to complying with the regulatory changes introduced in 2010. This is because these businesses only report aggregated vegetation management opex and to date have not been able to provide us with the incremental costs associated with changes in regulatory obligations.

Relying upon the 2015 cost estimates provides the starting point to prepare a preliminary estimate of the bushfire risk OEF for the Ergon Energy draft decision. However, the 2015 cost estimates need to be updated for two factors:

- The relevant benchmark periods used in our Ergon Energy draft decision. This draft decision is relying upon the 2006–17 and 2012–17 periods, as compared to the original 2006–13 period. This means that the incremental costs incurred by the Victorian distribution businesses will now apply from 2011 to 2017, rather than 2011 to 2013 in our 2015 decision. That is, they cover a larger proportion of the benchmarking period. This will increase the OEF estimate.[226]
- The specific service providers that we are comparing Ergon Energy against. The benchmark comparison firms are slightly different over 2006–17 and 2012–17, as compared to the original 2006–13 period. As previously noted, AusNet Services is no longer a benchmark comparator firm and its incremental costs associated with bushfire risk are excluded from the OEF estimate. This will reduce the OEF estimate.

Table A6.4 shows our updated OEF for bushfire risk for the 2006–17 and 2012–17 time periods. The negative bushfire risk OEF for Ergon Energy means that it faces a comparative cost advantage relative to the benchmark comparison firms, and this will increase the benchmark comparison point. Ergon Energy faces a higher cost advantage over the 2012–17 benchmark period, compared to the 2006–17 period, because the comparison businesses in Victoria have incurred higher bushfire management costs for each year of the benchmark period. In contrast, over the 2006–17 period, the Victorian businesses face incrementally higher costs from 2011–17, or approximately half of the benchmark period. As noted above, we have not quantified a material bushfire risk OEF for Energex.

Table A6.4 AER 2019 vegetation management OEFs (per cent)

	Energex	Ergon Energy
Bushfire risk – 2006–17	0.00	-3.36
Bushfire risk – 2012–17	0.00	-5.75

Source: AER analysis. The calculations for these adjustments are shown in the OEFs – Veg management update for Ergon and Energex spreadsheet included on our website with this draft decision.

[226] As noted above, we have not made corresponding adjustments for the other OEFs quantified by Sapere-Merz. This is because we have assumed that the underlying operating environment conditions associated with these OEFs remains consistent over time. This means we can apply the same OEFs over the 2006–17 and 2012–17 period.

Division of responsibility

In our 2015 opex final decision, we formed the view that Ergon Energy and Energex faced a cost disadvantage in the scale of vegetation management responsibility compared to the benchmark comparator firms in Victoria and South Australia. This was because distribution businesses are responsible for vegetation clearance from all network assets in Queensland, whereas in Victoria and South Australia, other parties such as councils, landowners and roads authorities are responsible for some vegetation clearance.[227] [228] As a result, Ergon Energy and Energex must undertake additional vegetation management responsibilities in the provision of network services.

We calculated a division of responsibility OEF for Ergon Energy and Energex by calculating the amount of line length where parties other than the distribution businesses were responsible for vegetation clearance in Victoria and South Australia.[229] We looked at the following information:

- The Victorian 2014 Electric Line Clearance regulatory impact statement provides some information on the division of vegetation management costs between service providers and councils in Victoria.[230] Information from the regulatory impact statement suggests that the councils are responsible for 24 per cent of electricity distribution and transmission vegetation management costs in Victoria.
- We asked the Victorian service providers to provide information on what percentage of their networks councils and other parties have responsibility for vegetation management. AusNet Services responded that it shared responsibility for vegetation management with councils for 12 per cent of its overhead route line length. The other distributors stated that it was difficult to estimate what percentage of their network other parties are responsible for because they shared responsibility for vegetation management of different trees on the same span.

On this information, we concluded that councils would appear to be responsible for somewhere between 12 per cent and 24 per cent of vegetation management in Victoria. For the purpose of estimating the opex impact created by differences in the division of responsibility for vegetation management, we assumed that councils are responsible for 18 per cent of vegetation management in Victoria. This was the midpoint of the two figures available to us.

We also assumed that councils in South Australia are responsible for a similar amount of vegetation management as their Victorian counterparts.

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227 Ergon Energy*, Information request 26(1),* 13 February 2015, p. 4.

228 Energex, *Information request 21*, 13 February 2015, p. 3.

229 AER, Preliminary decision, *Energex determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure*, April 2015, p. 217; AER, Preliminary decision, *Ergon Energy determination 2015−16 to 2019−20 Attachment 7 – Operating expenditure,* April 2015, p. 226.

230 Energy Safe Victoria, *Regulatory Impact Statement: Electricity Safety (Electric Line Clearance) Regulations 2015*, September 2014, p. 51.

Establishing that Ergon Energy retains a cost disadvantage in relation to division of responsibility

We remain of the view that Ergon Energy and Energex face a cost disadvantage in the scale of vegetation management responsibility compared to the benchmark comparator firms in Victoria and South Australia. This is because we understand in Queensland distribution businesses remain responsible for vegetation clearance from all network assets, whereas other parties such as councils, landowners and roads authorities remain responsible for some vegetation clearance in Victoria and South Australia.[231] [232]

Quantifying the division of responsibility component of the OEF for the draft decision

In this draft decision, we have calculated a division of responsibility OEF for Ergon Energy and Energex using the same method as in 2015. This is done by calculating:

- how much of the vegetated lines in Victoria and South Australia were managed by parties other than the distribution businesses in those states, and
- then multiplying the proportion of opex that relates to vegetation management by the proportionate increase in responsibility it faced relative to the Victorian and South Australian distribution businesses.

For the proportionate increase in responsibility relative to the Victorian and South Australian distribution businesses, we have retained the 2015 assumption that 18 per cent of the Victorian and South Australian networks share responsibility for vegetation clearance with councils and other parties. We understand the relevant obligations governing vegetation management responsibilities in Queensland, Victoria and South Australia have not changed since 2013. The distribution businesses also did not provide us with any information in their submissions to the Sapere–Merz review, or in the Frontier Economics report provided by Ergon Energy and Energex, that suggested the relevant responsibilities have changed.

We have also assumed that the underlying network boundaries have not changed materially (with the exception of some growth into new estates and suburbs), and that the average sharing of responsibility between network provider and councils remains similar. We are not aware of any new information about how much councils and other parties in Victoria have responsibility for vegetation management.

In relation to the proportion of network service that is vegetation management, we have recalculated the proportion of vegetation management within network services opex separately over 2006–17 and 2012–17. We then apply the proportionate increase in responsibility Ergon Energy and Energex face relative to the Victorian and South Australian distribution businesses (18 per cent) factor to each period.

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[231] Ergon Energy, *Information request 26(1),* 13 February 2015, p. 4.

[232] Energex, *Information request 21*, 13 February 2015, p. 3.

Table A6.5 shows our updated OEF for division of responsibility for the 2006–17 and 2012–17 time periods. The difference in OEF adjustments for each time period reflects differences in annual vegetation management opex incurred by Ergon Energy and Energex. This is consistent with the calculation approach we adopted in 2015.

Table A6.5 AER 2019 vegetation management OEF, division of responsibility (per cent)

	Energex	Ergon Energy
Division of responsibility – 2006–17	2.71	2.79
Division of responsibility – 2012–17	2.58	2.56

Source: AER analysis. The calculations for these adjustments are shown in the OEFs – Veg management update for Ergon and Energex spreadsheet included on our website with this draft decision.

B Further discussion on proposed base adjustment for Cost Allocation Method change

As mentioned above, this appendix provides further discussion of each of the proposed adjustments in relation to Ergon Energy and Energex's proposed CAM adjustment in more detail. This also sets out the nature of the further information that Ergon Energy and Energex may wish to provide in their revised proposals (in addition to evidence of external or internal verification and audit), should Ergon Energy and Energex wish to propose a similar adjustment in its revised proposal.

B.1 Proposed SPARQ adjustment

Ergon Energy stated that this movement of -$16 million ($2019–20) (-$13 million ($2019–20) for Energex) relates to a new treatment of ICT expenditure that reflects the dissolution of SPARQ and ICT being brought in-house.[233] We understand this has the effect of reducing the amount allocated to overheads (roughly equally to opex and capex[234]) and increasing the amount allocated to direct expenditure.

Ergon Energy also explained that, while this drives a reduction in the amount of overheads being allocated, this new treatment of ICT expenditure is not driven by the change in the CAM. The change is driven by the dissolution of SPARQ, rather than a CAM or accounting-related change. [235]

Energy Queensland stated that the value of these ICT changes was determined in the same way as the base year forecast.

> The base year forecast is derived using information from the 2018-19 corporate budget. Therefore, the value of the ICT Asset Usage Fee (representing depreciation and finance charges related to ICT assets managed by the legacy SPARQ business on behalf of the DNSPs) was removed as part of the 2018-19 annual budgeting process. [236]

We accept the presence of the underlying driver for this change (dissolution of SPARQ) and accept that directionally a negative movement in indirect opex would be expected. However, we require further evidence to demonstrate the quantum of the adjustment in terms of its net impact on total (direct and indirect) opex.

Should Ergon Energy wish to propose a similar adjustment in its revised proposal, we would encourage Ergon Energy to provide more detailed information in its revised

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233 Ergon Energy, *Information request #51 – Q13a*, 27 June 2019, p. 9; Ergon Energy, *Information request #56 – Q19-20*, 17 July 2019, pp. 17-18; AER analysis. We discuss SPARQ further in Attachment 5 at A.5, p. 47.

234 Ergon Energy, *6.003 – Base Year Opex Overview – 2020-25*, January 2019, p. 36-37.

235 Ergon Energy, *Information request 56 – Q19-20*, 17 July 2019, pp. 17-18.

236 Ergon Energy, *Information request 59 – Q3*, 8 August 2019, p. 1.

proposal that shows the data and calculations behind the estimated movement, including any business cases or management documents that formed a part of the decision making to support the 2018–19 annual budgeting process.

B.2 Accounting and costing alignments

We understand that this set of changes seeks to ensure alignment between the two businesses on various accounting and costing approaches (prior to application of the new common CAM on 1 July 2020).[237] The net amount of these adjustments for Ergon Energy is +$20 million ($2019–20) (and -$4 million ($2019–20) for Energex).[238] Ergon Energy and Energex stated these changes do not relate to alignment between current CAMs, but rather to the accounting treatment or categorisation of certain expenditures.[239]

Across both Ergon Energy and Energex, these changes seek to harmonise the accounting approaches:

- Classifying expenditure (between direct and indirect costs and between services)
- Capitalising expenditure
- Treatment of a certain identified expenditure (i.e. the change fund component of the negative base adjustments, see below.

In relation to classifying expenditure, we understand that this consists of changes to ensure alignment of approach between the two businesses.[240] Ergon Energy and Energex explained that these have limited impact on the total SCS Opex reported, as for each direct opex adjustment, there is a corresponding indirect opex adjustment.[241] As shown in table 6.6, there are three changes:

- Training expenditure: this is to be considered for Energex as direct opex rather than an overhead, to align with its treatment by Ergon Energy.
- Credit returns expenditures: this is to be considered for Ergon Energy as an overhead rather than a direct cost, to align with its treatment by Energex.
- Fleet expenditure: this is to be considered for Ergon Energy as an overhead rather than a direct cost, to align with its treatment by Energex.

Should Ergon Energy wish to propose a similar adjustment in its revised proposal, we would encourage Ergon Energy to provide more detailed information in its revised proposal that shows the data and calculations behind the estimated movements associated with these changes, as well as evidence of the existing and aligned

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237 Ergon Energy, *Information request 56 – Q19*, 17 July 2019, pp. 17.

238 Ergon Energy, *Information request 56 – Q16*, 17 July 2019, pp. 16; AER analysis.

239 Ergon Energy, *Information request 59 – Q6, 9, 11*, 8 August 2019, pp. 2-3.

240 Ergon Energy, *Information request 56 – Q19,* 17 July 2019, p. 17.

241 Ergon Energy, *Information request 56 – Q19b*, 17 July 2019, p. 17.

accounting policies. We would also wish to see evidence that these adjustments represent the net impact on total opex, i.e. the net impact on indirect opex after accounting for offsetting impacts on direct opex. Given that the classification of expenditure between direct and indirect costs, and between services, is generally covered by CAMs it would also be useful if Ergon Energy explained the relationship between these accounting approaches and the CAMs.

The capitalisation movement of +$17 million ($2019–20) for Ergon Energy relates to alignment of capitalisation approaches between the two businesses, via alignment of Ergon Energy's capitalisation approach with that of Energex. We understand that this has the net effect for Ergon Energy of allocating more (non-capitalisable) corporate costs to opex (relative to that under Ergon Energy's previous capitalisation policy).[242]

We would also welcome more detailed data and calculations behind the estimated movements in Ergon Energy's revised proposal, along with evidence to confirm the claim that Ergon Energy's proposed standard control service capex is lower than it otherwise would be without this capitalisation adjustment.[243] We would also wish to understand why particular aspects of either Ergon Energy's or Energex's costing approaches were adopted for alignment purposes. We would also encourage Ergon Energy to identify the specific elements in its capitalisation policy that have changed in its alignment to Energex, what the changes were, and to demonstrate that offsetting adjustments in capex (such as capitalised overheads) have been made.

Ergon Energy also identified a removal from the overheads pool of $4 million ($2019–20) in relation to the change fund component of the negative base adjustments.[244] The basis for this was not clear to us, noting that the same adjustment is also part of the negative adjustments from base opex (discussed above). We would also encourage Ergon Energy to further explain this movement in its revised proposal including the basis for the change, information that shows the data and calculations behind the estimated movement and why it is also a part of the negative base adjustments.

B.3 Change to new CAM

This category represents the change in indirect costs resulting from the application of the new CAM from 1 July 2020 to base year indirect costs (relative to indirect costs under the current CAM). We understand the estimates for these changes were developed once the proposed SPARQ and accounting costing alignments outlined above were applied.[245] That is, first the pool of base year indirect costs is established to reflect costing changes and alignments under the current CAMs. The new CAM is

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242 Ergon Energy, *Information request 56 – Q16 and 19*, 17 July 2019, pp. 16-17.

243 Ergon Energy states that SCS capex is lower as a result of this capitalisation adjustment, but does not provide supporting evidence. See Ergon Energy, *Information request 59 – Q8*, 8 August 2019, pp. 2-3.

244 Ergon Energy, *Information request 56 – Q16 and 19*, 17 July 2019, pp. 16-17.

245 Ergon Energy, *Information request 56 – Q19d*, 17 July 2019, p. 17.

then applied to that indirect cost pool to determine the impact of the new CAM in isolation.

Ergon Energy and Energex broke this category down into three movements:

- Changed corporate overhead allocation due to application of the corporate three factor method, resulting in higher indirect costs ($21 million ($2019–20)) being allocated to Energex given the higher customer numbers in the south-east
- Increased allocations resulting from various factors e.g. higher levels of labour expenditure, which contributes to a greater proportion of non-network costs allocated to standard control service opex.
- Unspecified/unexplained residual.[246]

In relation to the first movement, Ergon Energy and Energex explained that this estimate has been calculated as the difference between the 2015 CAM standard control service corporate expenditure and the 2020 CAM standard control service corporate expenditure.[247] This variance is the result of sharing common expenditure, such as corporate functions, across the merged Energy Queensland entity and the change in allocation method across the businesses and related services.[248] As described by Ergon Energy, indirect costs are initially split between the non-regulated and the regulated network businesses using a "corporate three factor method," an allocator which uses equal weightings of revenue, labour, and asset values to allocate these costs into the various areas. The corporate overheads that are allocated to the regulated network businesses are then allocated between Energex and Ergon Energy using the "distribution three factor method", which allocates using equal weightings of direct expenditure, customer numbers and asset values.[249]

As shown in table 6.6, Ergon Energy and Energex identified an increase in indirect costs of +$21 million ($2019–20) for Energex as a result of this change. The businesses were not able to separately identify an amount for this change for Ergon Energy, as we understand it is embedded in the net +$17 million ($2019–20) movement in relation to aligning its capitalisation policy with that of Energex (discussed above).[250]

Should Ergon Energy wish to propose a similar adjustment in its revised proposal, we would encourage Ergon Energy and Energex in their revised proposals to clearly identify the particular elements of its new CAM that have changed, compared to the

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246 Energex, *Information request 34 – Q1,* 11 June 2019, p.2; Ergon Energy, *Information request 51 – Q16*, 27 June 2019, p.10; Ergon Energy, *Information request 56 – Q16&19,* 17 July 2019, pp. 16-17; AER analysis.

247 Energex, *Information request 41 – Q15a,* 27 June 2019, p.8; Ergon Energy, *Information request 59 – Q12,* 8 August 2019, p. 3.

248 Ergon Energy, *Information request 59 – Q12,* 8 August 2019, p. 3.

249 Ergon Energy, *6.003 – Base Year Opex Overview – 2020-25*, January 2019, pp. 35-36.

250 Ergon Energy, *Information request 56 – Q22,* 17 July 2019, p. 18; Energex, *Information request 41 – Q15a,* 27 June 2019, p. 8.

current CAMs, and that are driving the movements. In relation to the amounts, while we acknowledge that Ergon Energy has adopted a top-down exercise, we would also be seeking evidence that allows us to see how the amounts were obtained, e.g. an Excel spreadsheet. This should also be sufficiently granular so that amounts for different drivers (e.g. capitalisation changes and CAM changes) are separated where possible. We would also wish to see evidence of a robust governance process that attests to the veracity of the calculated movements, e.g. internal or external audit.