DRAFT DECISION
Ausgrid
Distribution determination

2019−24

Attachment 6 – Operating expenditure

November 2018

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to Ausgrid for the 2019–24 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

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme

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Attachment 17 – Connection policy

Attachment 18 - Tariff structure statement

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
CCP/CCP10	Consumer Challenge Panel, sub-panel 10
distributor	distribution network service provider
DMIA/DMIAM	demand management innovation allowance mechanism
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
EUAA	Energy Users Association of Australia
Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
GSL	Guaranteed service level
LSECD	Cobb Douglas least squares estimation
LSETLG	Translog least squares estimation
MPFP	multilateral partial factor productivity
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
opex	operating expenditure
PIAC	Public Interest Advocacy Centre
RIN	regulatory information notice
SFACD	Cobb Douglas stochastic frontier analysis
WPI	Wage price index

6 Operating expenditure

Operating expenditure (opex) is the operating, maintenance and other non-capital expenses incurred in the provision of network services. Forecast opex for standard control services is one of the building blocks we use to determine a service provider's annual total revenue requirement.[1]

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

6.1 Draft decision

Our draft decision is to include a substitute estimate of total forecast opex of $2,344.1 million ($2018–19) in Ausgrid's revenue for the 2019–24 regulatory control period.[2] We do not accept the total forecast opex in Ausgrid's proposal. Our total forecast is 4 per cent lower than Ausgrid's proposal of $2,442.5 million ($2018–19).

Our estimate is a decrease of 15.8 per cent from Ausgrid's actual opex in the current regulatory control period. We consider this forecast reasonably reflects the opex criteria and:

- reflects the significant opex efficiency gains Ausgrid forecasts to make in the current period, and maintains these over the 2019–24 regulatory period
- provides for demand management costs that will defer replacement capital expenditure (repex) projects that would otherwise commence in the 2019–24 regulatory period
- makes allowance for expected increases in input costs (including the cost of labour), and in the costs of operating a larger network with more customers.

We used our standard 'base-step-trend' approach to develop our estimate.[3] The total opex forecast we have adopted in this draft decision starts with Ausgrid's estimated costs in 2017–18 as a base year. We have then forecast growth in prices, output and productivity using our standard approach (with some refinement) and assessed Ausgrid's step changes in accordance with our *Expenditure forecast assessment guideline* (the Guideline).[4]

The difference between Ausgrid's proposed forecast opex and our estimate is because:

- We have rolled forward Ausgrid's estimate of 2017–18 opex by escalating it by the rate of change. In contrast, Ausgrid applied the *Expenditure forecast assessment*

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1 NER, cl.6.4.3(a)(7).

2 NER, cl.6.12.1(4)(ii); Includes debt-raising costs.

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

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

guideline (the Guideline) formula to its estimate of 2017–18 opex. That formula assumes the Efficiency Benefit Sharing Scheme (EBSS) has applied in the period from which the base year is selected. In this case, it did not.

- The demand management costs that we have included in our total opex forecast are lower than Ausgrid proposed. Our alternative forecast includes three of Ausgrid's demand management proposals, but does not include a further four projects that we consider have not been adequately justified.
- Our forecast also excludes Ausgrid's proposed step increase in opex for research into, and engagement on, network tariff reform. While we support further consideration and engagement by Ausgrid on how best to transition to cost reflective pricing, we consider that this type of activity is part of a distributor's standard business activities and is accommodated within the existing costs and base year opex.
- We currently do not have sufficient information to make a determination on Ausgrid's proposed adjustment to increase its base year opex for Emergency Recoverable Works costs, and consequently have not included this in our opex forecast.[5] We invite further information from Ausgrid to better understand how these costs and revenues have been accounted for over the 2014–19 regulatory period to allow consideration of the issue in our final decision.
- Our forecast of the expected increase in real labour prices in NSW is lower than that proposed by Ausgrid. We have applied our standard approach by averaging the forecasts of growth in the NSW utilities wage price index by our consultant Deloitte Access Economics and Ausgrid's consultant, BIS Oxford Economics. In contrast, Ausgrid only applied BIS Oxford Economics' forecast.
- Our forecast of expected increases in the costs of operating a larger network (output growth) is also lower than Ausgrid's. We have used output weights derived from the results of four of the models we presented in our 2017 annual benchmarking report. This is a refinement of our previous approach, which used the weights from a single econometric model.[6] Ausgrid adopted our previous approach.

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

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5 Following the introduction of the AER's Ring-Fencing Guideline, Emergency Recoverable Works (ERW), which were previously classified as an unregulated service, will now be subsumed into the common distribution services group and classified as a standard control service. We have requested further information from Ausgrid on this issue.

6 We have derived weights from the results four economic benchmarking models — Cobb-Douglas stochastic frontier analysis, Cobb-Douglas least squares econometrics, translog least squares econometrics and opex multi-lateral partial factor productivity. We had previously relied solely on the results of our Cobb-Douglas stochastic frontier analysis model, which is the basis of Ausgrid's proposal.

The AER's Consumer Challenge Panel (CCP10) submitted that a zero per cent productivity growth rate is not in the best interests of customers and that there is evidence to support the use of a positive productivity growth forecast. CCP10 recommends that:[7]

> '… the AER … consider whether, particularly given the current performance of the NSW businesses, Ausgrid and Endeavour Energy's assumptions of zero trend productivity improvement are in the best interests of consumers. We consider that consumers should expect ongoing improvements in productivity and that this is consistent with the pressures on businesses in competitive markets to continuously search for productivity improvements.

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

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

Ausgrid's forecast opex and our draft decision are set out in table 6.1.

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

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Ausgrid's proposed opex	471.1	478.9	489.1	498.1	505.4	2442.5
AER draft decision	456.2	460.8	468.6	476.1	482.3	2344.1
Difference	–14.8	–18.1	–20.5	–22.0	–23.1	–98.4

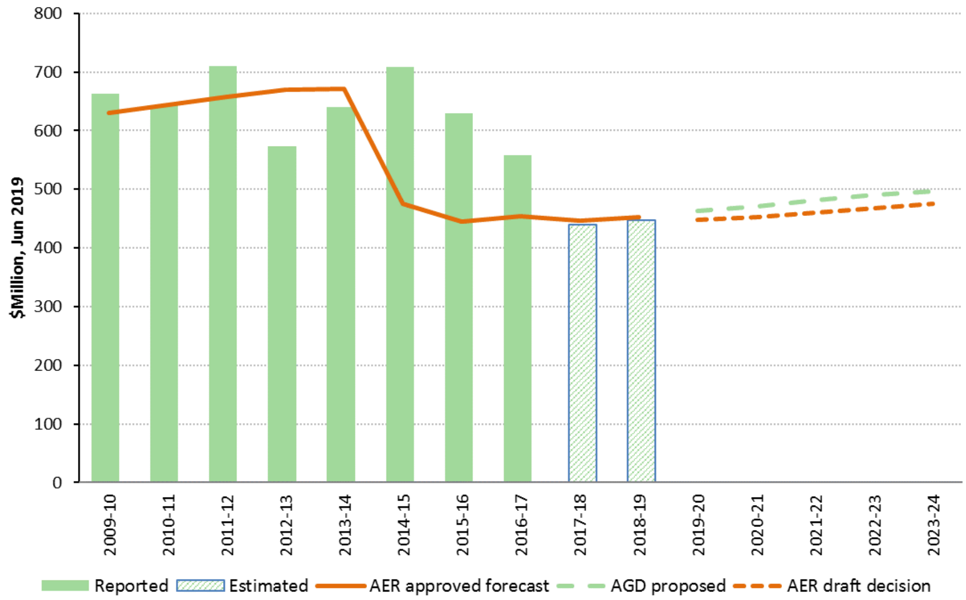
Source: Ausgrid, *Revenue proposal*, *Post tax revenue model (PTRM)*, April 2018; AER analysis

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

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

[7] Consumer Challenge Panel (Subpanel 10), *CCP10 Response to AER Issues paper and revenue Proposals for NSW Electricity Distribution Businesses 2019-24,* August 2018, pps.30-31.

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



Source: AER analysis; Ausgrid transmission and distribution PTRM, April 2018.

Note: Excludes debt raising costs. The reported opex and the AER approved forecast in the 2009-14 regulatory period corresponds to the service classification and cost allocation methodology in place at the time.

6.2 Ausgrid proposal

Ausgrid's forecast opex of $2,442.5 million ($2018–19) is a decrease of 12.2 per cent from its actual and estimated opex for the 2014–19 regulatory control period.[8]

Table 6.2 sets out Ausgrid's proposed opex for each year of the 2019–24 regulatory control period.

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

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Opex excluding debt raising costs	463.2	470.8	481.0	490.0	497.3	2,402.3
Debt raising costs	7.9	8.0	8.1	8.1	8.1	40.2
Total opex	471.1	478.9	489.1	498.1	505.4	2,442.5

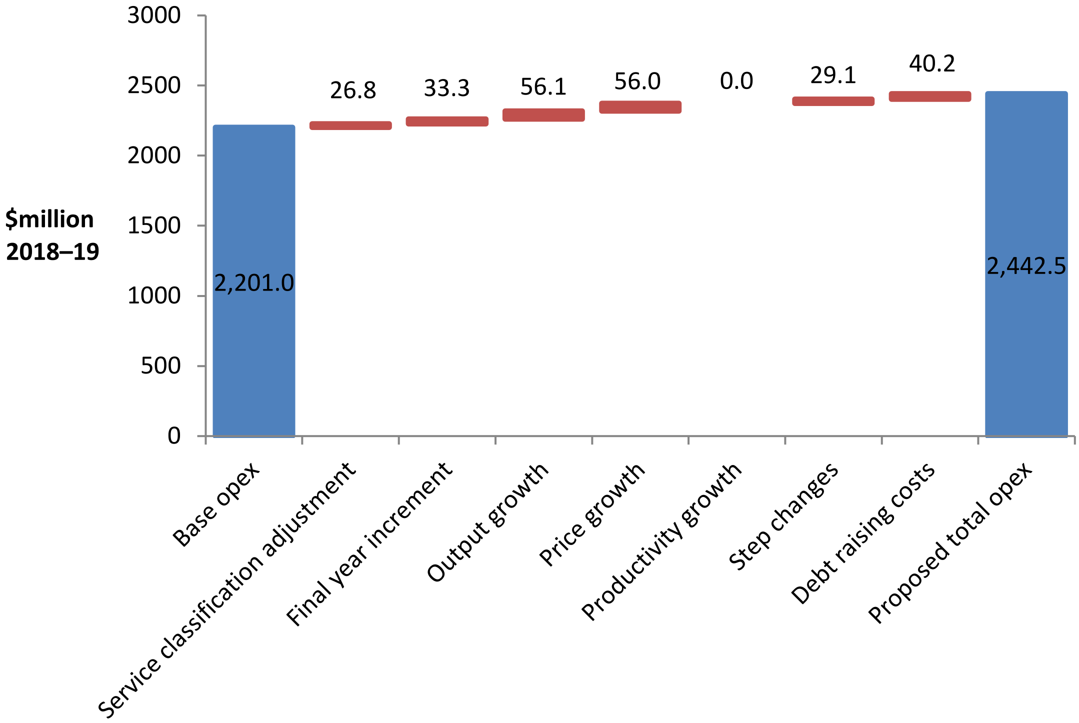
Source: Ausgrid regulatory proposal

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

[8] Our April 2015 final decision set an opex forecast for Ausgrid for the current 2014-19 regulatory period that was 25.6 per cent lower than the amount proposed by Ausgrid. Ausgrid appealed this decision to the Australian Competition Tribunal and the Federal Court and we are in the process of remaking our opex forecast as part of a remade 2014–19 determination. Ausgrid estimates its actual opex for the 2014-19 regulatory period will be 29.8 per cent above our 2015 final decision opex forecast.

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

Figure 6.2 Ausgrid's opex forecast breakdown



Source: AER analysis.

Ausgrid states that it has adopted our revealed cost approach to forecasting opex (the 'base-step-trend' approach). The key elements of Ausgrid's proposal are:

- Ausgrid uses its estimated opex less transition costs in 2017–18[9] (its base year) to derive a base year opex of $2,201.0 million ($2018–19).
- Ausgrid has included an upward adjustment to its base year opex to account for the effect of change to the service classification of Emergency Recoverable Works (ERW) costs.[10] This increased its base opex by $26.8 million ($2018–19).
- Ausgrid applied the Guideline formula to its estimated opex in 2017–18 to derive its estimated opex in 2018–19. This increased its opex by $33.3 million ($2018–19).

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

10 The proposed base year adjustment is to include Emergency Recoverable Works (ERW) costs, which were previously classified as an unregulated service but, following the introduction of the AER's Ring-Fencing Guideline, will be subsumed into the common distribution services group and classified as a standard control service from 2019-20.

- Ausgrid then trended forward its base opex to account for:
  - Expected increases in real input prices, including forecast increases in labour costs and an increase in line with CPI for non-labour costs ($56.0 million, $2018–19).
  - Forecast output growth, driven primarily by increased customer numbers, circuit line length and ratcheted maximum demand, all of which increases the cost to Ausgrid of operating its network ($56.1 million, $2018–19).
  - Forecast zero change in opex productivity over the regulatory period.[11]
- Ausgrid has included two step changes in its opex forecast:
  - $26.1 million to fund demand management to defer repex and augmentation capital expenditure (augex) projects that would otherwise commence in the 2019–24 regulatory control period.
  - $3.0 million ($1.5 million in both 2019–20 and 2020–21) to fund a pricing reform acceptance research project to inform Ausgrid's transition to more cost reflective pricing in accordance in accordance with the Australian Energy Market Commission’s (AEMC) 2014 rule change for Distribution Network Pricing Arrangements.[12]
- Ausgrid has forecast $40.2 million ($2018–19) of debt raising costs. Debt raising costs are transaction costs incurred each time debt is raised or refinanced.

6.2.1 Submissions on Ausgrid's proposal

We received seven submissions on Ausgrid's opex proposal. These were from AGL Energy, CCP10, Energy Consumers Australia (ECA), Energy Users Association of Australia (EUAA), Origin Energy, City of Sydney and the Public Interest Advocacy Centre (PIAC). Broadly, the submissions related to Ausgrid's zero productivity forecast, and its proposed step changes.

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

6.3 Assessment approach

Our role is to form a view about whether a business's forecast of total opex is reasonable. Specifically, we must form a view about whether a business's forecast of total opex 'reasonably reflects the opex criteria'.[13] In doing so, we must have regard to each of the opex factors specified in the NER.[14]

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

12 See: https://www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements

13 NER, cl. 6.5.6(c).

14 NER, cl. 6.5.6(e).

If we are satisfied the business's forecast reasonably reflects the criteria, we must accept the forecast.[15] If we are not satisfied, we are required to substitute an alternative estimate that we are satisfied reasonably reflects the opex criteria taking into account the opex factors.[16] In making this decision, we take into account the reasons for the difference between our alternative estimate and the business's proposal, and the materiality of the difference. Further, we consider interrelationships with the other building block components of our decision.[17]

The *Expenditure forecast assessment guideline* (the Guideline) together with its explanatory statement set out our intended approach to assessing opex in accordance with the NER. [18] We published the Guideline and the associated explanatory statement in November 2013 following an extensive consultation process with service providers, network users, and other stakeholders. While the Guideline provides for greater regulatory predictability, transparency and consistency, it is not mandatory. However, if we make a decision that is not in accordance with the Guideline, we must state the reasons for departing from the Guideline.[19]

We apply the assessment approach outlined in the Guideline to develop our estimate of a business's total opex requirements (our alternative estimate).

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

6.3.1 Incentive regulation and the 'top-down' approach

Incentive regulation is designed to prevent network businesses from exploiting their natural monopoly position by setting prices in excess of efficient costs.[20] A key feature of the regulatory framework is that it is based on incentivising networks to be as efficient as possible. We apply incentive-based regulation across the energy networks we regulate, including electricity distribution networks. More specifically for opex, we rely on the efficiency incentives created by both ex ante revenue regulation (where an opex allowance is granted over a multi-year regulatory period) and the efficiency benefit sharing scheme' (EBSS).

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us, the regulator.[21]

Incentive regulation encourages regulated businesses to reduce costs below the regulator's forecast, in order to make higher profits, and ‘reveal’ their costs in doing so.

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15 NER, cl. 6.5.6(c).

16 NER, cll. 6.5.6(d) and 6.12.1(4)(ii); the opex factors are outlined at cl.6.5.6(e).

17 NEL, s. 16(1)(c).

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

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

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

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

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 business's forecast opex over the regulatory control period at a total level, rather than to assess individual opex projects or programs. To do so, we develop an alternative estimate of total opex using a 'top-down' forecasting method, known as the 'base–step–trend' approach (section 6.3.2).[22]

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.[23] We may make a negative 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.[24] 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 the day-to-day decisions to the network businesses.[25] It allows the network businesses the flexibility to manage their assets and labour as they see fit to achieve the opex objectives in the NER,[26] and more broadly, the National Electricity Objective (NEO).[27] 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.[28]

The Australian Energy Market Commission (AEMC) supports this view of our role as the economic regulator. It stated: [29]

> 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

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22 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'.

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

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

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

26 NER, cl. 6.5.6(a).

27 NEL, s. 7.

28 NER, cl. 6.5.6(c).

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

> 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

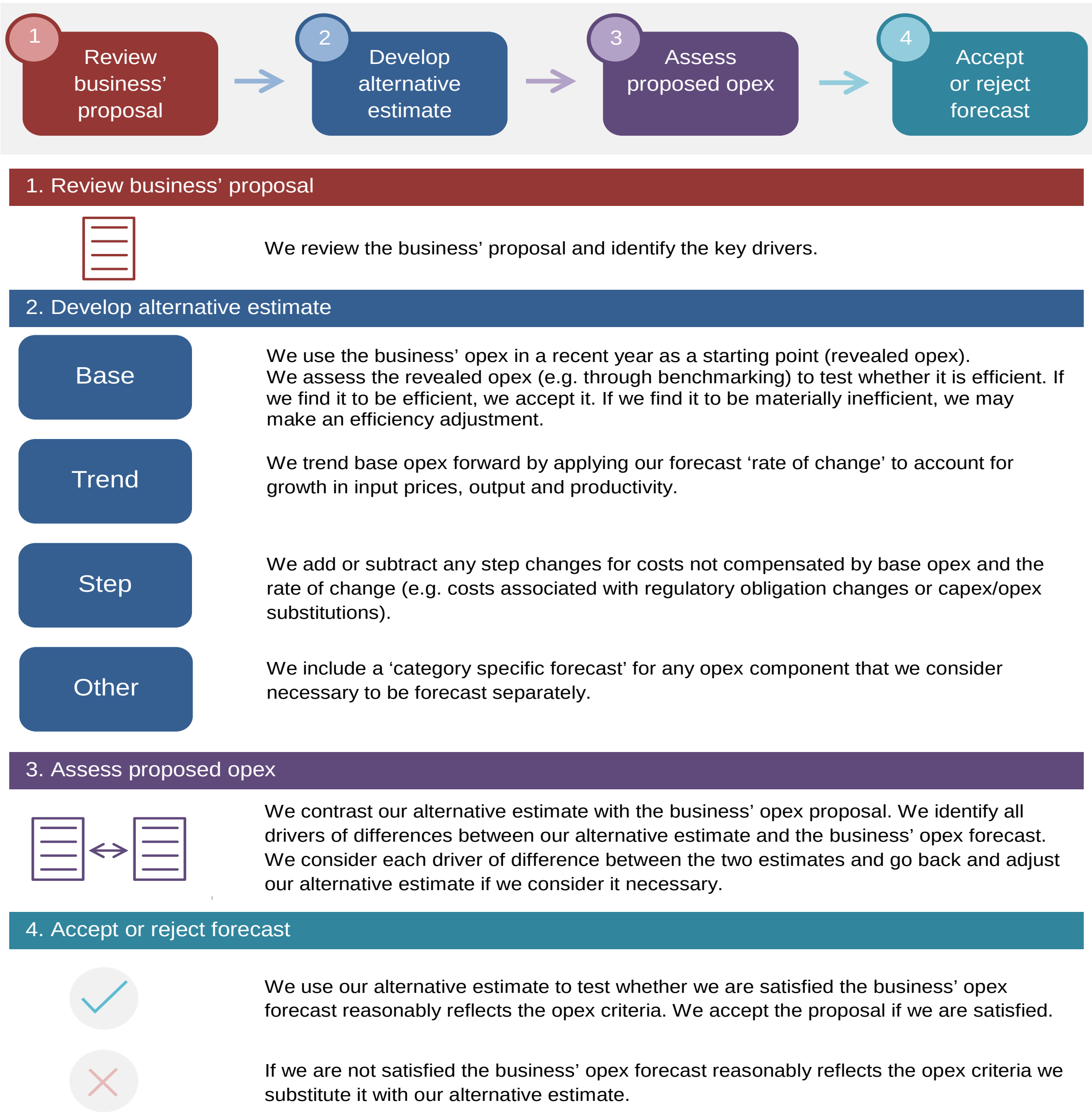
As a comparison tool to assess a business’s opex forecast, we develop an alternative estimate of the business's total opex requirements in the forecast regulatory control period, using the base–step–trend forecasting approach. We also have regard to the opex factors set out in the NER.[30]

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

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

[30] 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.[31]

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[32] and other assessment techniques to test whether the business is operating efficiently.

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

[32] AER, *Annual benchmarking report—Electricity distribution network service providers*, November 2017.

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

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

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

Rate of change

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

We forecast input price growth using a composition of labour and non-labour price changes forecasts. Labour costs represent a significant proportion of a distribution business's costs.[33] 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 annual increase in output. The output measures used should be the same measures used to forecast productivity growth.[34] Productivity measures the change in output for a given amount of input. If the output measures differ from the productivity measures, they would be internally inconsistent and we cannot compare them like for like.

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

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

34 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 23.

Our forecast of productivity growth represents our best estimate of the shift in the industry 'efficiency frontier'.[35] We generally base our estimate of productivity growth on recent productivity trends across the industry. However, if we consider historic productivity growth does not represent 'business-as-usual' conditions we do not use it to forecast future productivity growth.

Our standard approach to forecasting the productivity component of our opex the rate of change in past decisions has been to apply zero productivity growth. In its submission to our issues paper, CCP 10 submits that a zero productivity improvement over five years is not in the best interests of customers. CCP10 contends that:[36]

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

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

Step changes and category-specific forecasts

Lastly, we add or subtract any components of opex that are not adequately compensated for in base opex or the rate of change, but which should be included in the forecast total opex to meet the opex criteria.[37] 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 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.[38] In addition, forecast productivity growth may account for the cost of increased regulatory obligations over time—that is, 'incremental changes in obligations are likely to be compensated through a lower productivity estimate that accounts for higher costs resulting from changed obligations.'[39] 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.[40]

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

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

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

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

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

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

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.[41] Our starting position is that only exceptional circumstances would warrant the inclusion of a step change in the opex forecast because they may change a business's fundamental opex requirements.[42] Two typical examples are:

- a material change in the business's regulatory obligations
- an efficient and prudent capex/opex substitution opportunity.[43]

We may accept a step change if a material 'step up' or 'step down' in expenditure is required by a network business to prudently and efficiently comply with a new, binding regulatory obligation that is not reflected in the productivity growth forecast.[44] 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 periods; hence, an increase in its opex forecast may be warranted.

We expect the business to provide evidence demonstrating the material impact the change of regulatory obligation has on its opex requirements, and robust cost–benefit analysis to demonstrate the proposed step change expenditure is prudent and efficient to meet the change in regulatory obligations.[45] We stated in the explanatory statement accompanying the Guideline:[46]

> [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

41 NER, cl. 6.5.6(a).

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

43 NER, cl. 6.5.6(e)(7).

44 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

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

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

> identifiable. If the obligation is not new, we would expect the costs of meeting that obligation to be included in revealed costs. We also consider it is efficient for [Network services providers] to take a prudent approach to managing risk against their level of compliance when they consider it appropriate (noting we will consider expected levels of compliance in determining efficient and prudent forecast expenditure).

By contrast, proposed opex projects designed to improve the operation of the business, which we consider as discretionary in the absence of any legal requirement, should be funded by base opex and trend components, together with any savings or increased revenue that they generate—rather than through a step change. Otherwise, the business would benefit from a higher opex forecast and the efficiency gains.[47]

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.[48] The business should provide robust cost–benefit analysis to clearly demonstrate how increased opex would be more than offset by capex savings.[49]

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

Category specific forecasts

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

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

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47 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

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

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

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

6.3.3 Interrelationships

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

- the impact of cost drivers that affect both forecast opex and forecast capex. For instance, forecast labour price growth affects forecast capex and our forecast of forecast price growth used to estimate the rate of change in opex
- its proposed demand management step change to defer repex and augex
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- concerns of electricity consumers identified in the course of Ausgrid's engagement with consumers.

6.4 Reasons for draft decision

Our draft decision is to substitute total forecast opex of $2,344.1 million ($2018–19) in Ausgrid's revenue for the 2019–24 regulatory control period.[50] We consider that this substitute forecast reasonably reflects the opex criteria. Our total forecast is 4.0 per cent lower than Ausgrid's proposal of $2,442.5 million ($2018–19). This is because:

- We have rolled forward Ausgrid's estimate of 2017–18 opex by escalating it by the rate of change. In contrast, Ausgrid calculated its estimated opex for 2018–19 by applying the Guideline formula.
- The step change for demand management projects that we have included in our total opex forecast is lower than Ausgrid proposed. Our alternative forecast includes three of Ausgrid's demand management proposals, but does not include a further four projects that we consider have not been adequately justified.

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[50] Includes debt-raising costs.

- Our forecast also excludes Ausgrid's proposed step increase in opex for research into, and engagement on, network tariff reform. While we support further consideration and engagement by Ausgrid on how best to transition to cost reflective pricing, we consider this type of activity is part of a distributor's standard business activities and is accommodated within the existing costs and base year opex.
- We currently do not have sufficient information to make a determination on Ausgrid's proposed adjustment to increase its base year opex for Emergency Recoverable Works costs, and consequently have not included this in our opex forecast.[51] We seek further information from Ausgrid to better understand how these costs and revenues have been accounted for over the 2014–19 regulatory control period to allow consideration of the issue in our final decision.
- Our forecast of the expected increase in real labour prices in NSW is lower than that proposed by Ausgrid. We have applied our standard approach by averaging the forecasts of growth in the NSW utilities wage price index by our consultant Deloitte Access Economics and Ausgrid's consultant, BIS Oxford Economics. In contrast, Ausgrid only applied BIS Oxford Economics' forecast.
- Our forecast of expected increases in the costs of operating a larger network (output growth) is also lower than Ausgrid's. We have used output weights derived from the results of four of the models we presented in our 2017 annual benchmarking report. This is a refinement of our previous approach, which used the weights from a single econometric model.[52] Ausgrid adopted our previous approach.

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

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

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51 Following the introduction of the AER’s Ring-Fencing Guideline, Emergency Recoverable Works (ERW), which were previously classified as an unregulated service, will now be subsumed into the common distribution services group and classified as a standard control service. We have requested further information from Ausgrid on this issue.

52 We have derived weights from the results of four economic benchmarking models — Cobb-Douglas stochastic frontier analysis, Cobb-Douglas least squares econometrics, translog least squares econometrics and opex multi-lateral partial factor productivity. We had previously relied solely on the results of our Cobb-Douglas stochastic frontier analysis model, which is the basis of Ausgrid's proposal.

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

	Ausgrid	Our alternative estimate	Difference
Base opex	2201.0	2197.1	–4.0
Base opex adjustment for Emergency Recoverable Works	26.8	–	–26.8
2017–18 to 2018–19 increment	33.3	18.4	–15.0
Price growth	56.0	32.4	–23.6
Output growth	56.1	49.1	–6.9
Productivity growth	–	–	0.0
Step changes	29.1	8.5	–20.7
Debt raising costs	40.2	38.7	–1.5
Total opex	2442.5	2344.1	–98.4

Source: Ausgrid, Attachment 6.02, Opex model, April 2018; AER analysis.

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

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

6.4.1 Base opex

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

Ausgrid proposes to use its target opex for 2017–18 as the base to forecast opex over the 2019–24 regulatory control period, less transition costs.[53] It estimates that this base year opex will be $440.2 million ($2018–19).[54]

We have assessed the efficiency of Ausgrid's proposed base year using multiple techniques and information sources, including its revealed opex over the 2014-19 regulatory control period, a review of its expenditure cost categories and recent economic benchmarking analysis.

As outlined in our Expenditure Forecast Assessment Guideline, our preferred approach for forecasting opex is to use a revealed cost approach.[55] This is because opex is

53 Transition costs are the costs incurred by Ausgrid in the current period to reduce its opex to a level consistent with our April 2015 final decision and include redundancy, stranded labour and career transition program costs.

54 Ausgrid, *Ausgrid's Regulatory Proposal 1 July 2019 to 30 June 2024*, Attachment 6.01, April 2018, p.15.

largely recurrent and stable at a total level between regulatory periods. Where a distributor is responsive to the financial incentives under the regulatory framework, the actual level of opex it incurs should provide a good estimate of the efficient costs required for it to operate a safe and reliable network and meet its relevant regulatory obligations.

The revealed cost data show that after 2012–13,[56] Ausgrid's opex increases and peaks in 2014–15, then declines in each subsequent year of the current period. By 2018–19, Ausgrid forecasts that its opex will be significantly below its 2012–13 opex and at a level consistent with our April 2015 decision.

Category level cost analysis of Ausgrid's revealed opex over the current period shows that the initial increase above 2012–13 levels and our April 2015 forecast is primarily driven by higher transition[57] costs associated with the business' restructuring program. The subsequent decline in opex to a level consistent with our April 2015 decision by 2018-19 is driven by:

- Cost savings Ausgrid achieved in recurrent opex categories (including maintenance, emergency works and overheads) between 2014–15 and 2016–17, which it forecasts to maintain in 2017–18 and 2018–19.
- Decreases in transition costs in 2017–18 and 2018–19 as Ausgrid's transformation program winds down.

Ausgrid states that it will be able to sustain its 2018–19 target opex over the 2019–24 regulatory control period. To this end, Ausgrid has proposed its 2017–18 opex excluding transition costs (a level of opex that is consistent with its 2018–19 target opex) as its base year for its 2019–24 revenue forecast.[58]

This revealed costs data suggests that Ausgrid has responded to the strong incentives imposed by our regulatory regime to significantly reduce its opex over the current regulatory period. It supports the view that Ausgrid's 2018–19 target opex likely represent a sustainable and efficient level of recurrent opex that would allow for the safe and reliable provision electricity services to consumers. It also supports the view that Ausgrid's proposed 2017–18 base year opex, which is of a level consistent with its 2018–19 target opex, likely represent a sustainable and efficient level of recurrent opex.

We have cross-checked the findings of our revealed cost analysis with economic benchmarking to test the efficiency of Ausgrid's proposed base year opex. The benchmarking results support the view that Ausgrid's base year opex (its target opex in

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

56 In April 2015 we found that Ausgrid's 2012-13 opex (proposed as its base year for the 2014-19 period) was materially inefficient and this decision was upheld by the Tribunal in its 2016 decision.

57 In line with our April 2015 decision and the Tribunal and Federal Court decisions, we will use the term 'transition costs' in this decision when referring to Ausgrid's transformation costs.

58 Ausgrid, *Ausgrid's Regulatory Proposal 1 July 2019 to 30 June 2024*, April 2018, p.130.

2017–18 less transition costs) and its 2018–19 target opex are not materially inefficient.

Taken together, the results of the revealed cost and benchmarking indicate that Ausgrid’s proposed base year opex reasonably reflects an efficient and sustainable level of opex consistent with the opex criteria. Therefore, we propose to rely on the revealed costs in Ausgrid's base year for the purposes of forecasting opex over the 2019–24 regulatory control period.[59]

Below we outline in more detail our consideration of Ausgrid’s proposed opex using its revealed costs information and the benchmarking results.

Ausgrid's revealed costs over 2014–19

This section examines Ausgrid’s actual and estimated costs between 2012–13 (its proposed base year for its 2014–19 revenue proposal) and 2018–19 (the last year of the current regulatory period).

In April 2015, we made a decision on Ausgrid's opex forecast for the 2014–19 regulatory control period. In our decision, we found that the actual opex incurred by Ausgrid in its proposed base year of 2012–13 was materially greater than what a prudent and efficient network service provider would incur in delivering safe and reliable network services to customers. As a result, we found that Ausgrid’s actual opex for this year could not be used as a basis to forecast opex for the 2014–19 regulatory control period. Consistent with the NER, we substituted a lower base opex amount as the starting point of our substitute estimate for the 2014–19 regulatory control period. In doing this, we applied one of our economic benchmarking models to estimate our substitute base opex amount.

Our April 2015 decision was set aside by the Australian Competition Tribunal and we were required to remake our decision in accordance with the Tribunal's directions. On 15 August 2018, Ausgrid submitted a proposal for the remaking of our decision for the 2014–19 regulatory control period.[60] We are currently in the process of making our decision on this proposal.

Ausgrid has faced a strong incentive to reduce its costs over the 2014–19 regulatory control period. Our April 2015 decision found that Ausgrid’s proposed base opex for 2014–19 was materially inefficient and we did not accept its opex proposal. Our substitute opex forecast in this decision was significantly below its actual costs at the start of the 2014-19 regulatory period. While the Australian Competition Tribunal directed us to remake our April 2015 opex forecast, Ausgrid faced uncertainty around

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[59] Ausgrid's proposed $440.2 million ($2018–19) base year opex is derived from a nominal $426.39 million. We have used a base opex amount of $439.41 million ($2018–19), which reflects the latest inflation information in converting the nominal $426.39 million to $2018–19 terms.

[60] Ausgrid, *Proposal for the remake of Ausgrid's 2014-19 distribution determination* (proposal), 15 August 2018.

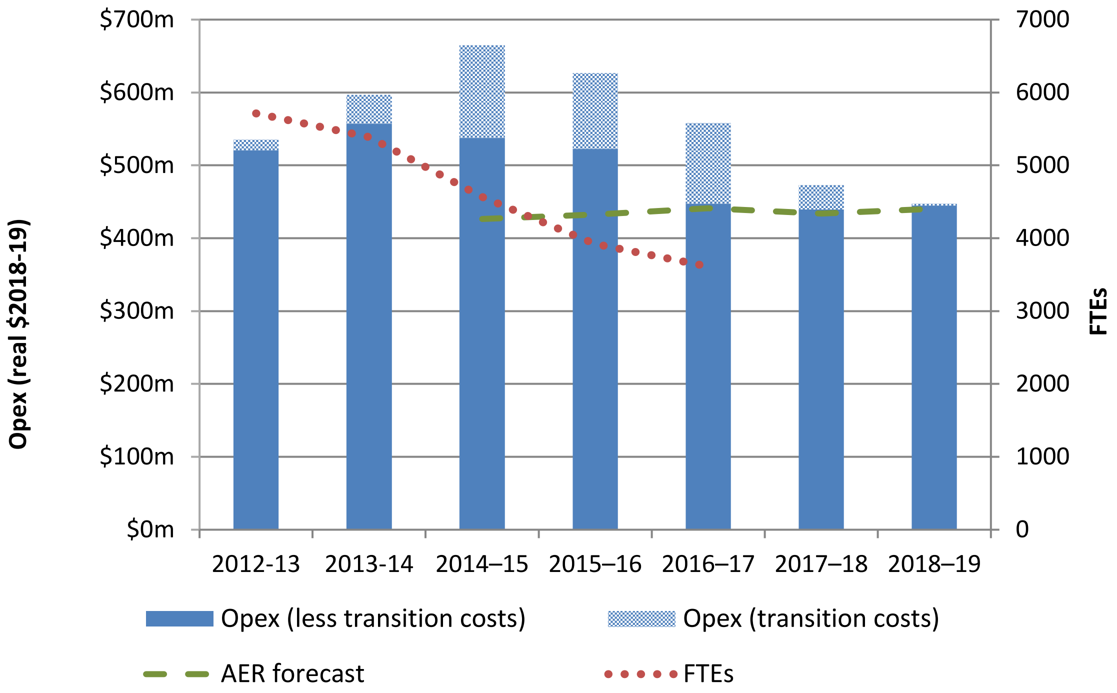
its final revenue allowance throughout the appeals process and we have yet to remake our opex decision for the 2014-19 regulatory control period.

In its proposal for the remaking our decision for the 2014–19 regulatory control period, Ausgrid recognised that this uncertainty has incentivised it to achieve the 'quickest' transition to a level of opex it believed would be consistent with our final opex forecast.[61] In this context, Ausgrid has also stated:[62]

> [it] had no certainty that it would be able to recover the transformation costs incurred. This uncertainty provided strong incentives to deliver the transformation at the lowest possible cost.

Figure 6.4 shows Ausgrid's actual opex up to 2016–17 and its opex forecasts for 2017–18 and 2018–19. The transition cost component of total opex is shown in light blue. These transition costs are discussed further below.

Figure 6.4 Ausgrid's opex, AER forecast opex in 2015 final decision, including movements in FTEs



Source: AER 2015 final decision; Ausgrid Annual RIN; Ausgrid 2019-24 regulatory proposal; Annual reports.

Note: Actual opex has been normalised by excluding metering and ancillary costs prior to 2014–15 and cost pass throughs. Opex in 2017-18 is based on Ausgrid's proposed base year opex of $440.2 million. Opex in 2018-19 is based on Ausgrid's Reset RIN.

61 Ausgrid email, 24 May 2018.

62 Ibid.

Figure 6.4 shows that Ausgrid's total opex increases after 2012–13 (the base year of Ausgrid's original 2014–19 revenue proposal), peaks in 2014–15, then declines in each subsequent year of the 2014–19 regulatory control period. By 2018–19 (the last year of the current period), Ausgrid's opex forecast is significantly below its 2012–13 opex and at a level consistent with our April 2015 decision. Ausgrid's proposed 2017–18 base year (its 2017-18 target opex less transition costs) is also consistent with its target 2018–19 opex and our April 2015 decision.

In its opex proposal, Ausgrid notes:[63]

> Our base year opex is in line with the AER's opex allowance for 2017–18 and is consistent with the AER's view of efficient costs, as outlined in the AER's 2015 Determination. We consider this is representative of our efficient recurrent opex requirements for 2019–24.

Over the first three years of the current period (2014–15, 2015–16 and 2017–18), Ausgrid's opex was above its 2012–13 level and our April 2015 opex forecast. This was primarily due to increased transition costs incurred by Ausgrid as it restructured and downsized its workforce. Over this same period, Ausgrid was able to reduce its total opex by approximately 20 per cent by achieving cost reductions in opex categories excluding transition costs, in particular maintenance, emergency and overheads (see the opex category analysis discussion below). Ausgrid forecasts it will be able to maintain these costs reductions in 2017–18 and 2018–19 while reducing transition costs, resulting in a further decrease in total opex to a level consistent with our April 2015 decision by 2018–19.

This revealed cost data indicates that Ausgrid is responding to the incentives imposed by the regulatory regime by achieving sustainable operational efficiencies that will allow it to significantly reduce its opex by 2018–19. This supports the view that Ausgrid's 2018–19 opex target and its proposed 2017–18 base year opex, which is of a similar level, represents a significant improvement in its opex efficiency.

In its regulatory proposal for the 2019–24 regulatory control period, Ausgrid states that it has achieved its opex savings through a two-stage transformation program which, amongst other things, has included:[64]

- improved safety performance and practice
- re-aligning structure and capability to meet future growth and goals
- rebalancing the size of office to field resources
- greater efficiencies and improved prioritisation in the field
- rolling out new, safer ways of working
- improving efficiency in field, reinvest in capital program delivery

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63 Ausgrid, *Ausgrid's Regulatory Proposal 1 July 2019 to 30 June 2024*, April 2018, p.131.

64 Ausgrid, *Ausgrid's Regulatory Proposal 1 July 2019 to 30 June 2024*, April 2018, p.123.

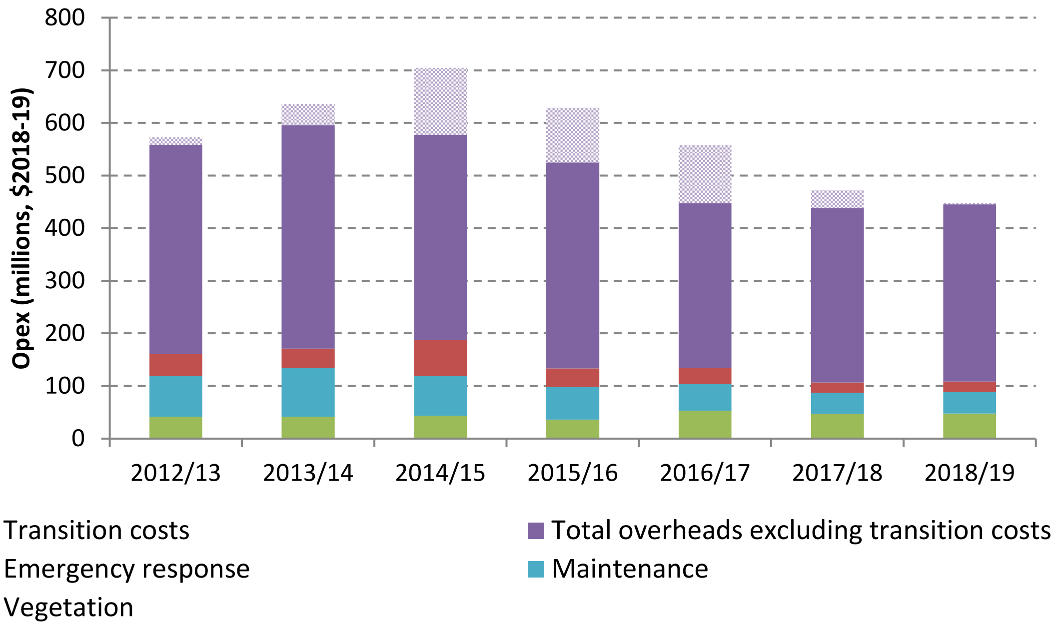
- delivering better and more consistent customer service
- improving corporate process and cost efficiency
- investing in new technology.

This has led to reductions across Ausgrid's major cost categories. Figure 6.5 shows the breakdown of Ausgrid's major opex cost categories using actual data up to 2016–17 and forecast data for 2017–18 and 2018–19. Between 2012–13 and 2017–18, the decrease in Ausgrid's total opex was driven by reductions in:

- emergency services – reduced by 53.7 per cent
- maintenance – reduced by 47.4 per cent
- total overheads (including transition costs) – reduced by 11.4 per cent.

Over the same period, vegetation management costs are forecast to increase by around 12.7 per cent.

Figure 6.5 Ausgrid's opex cost breakdown



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

Note: Transition costs are a subcomponent of total overheads. Data for 2017–18 and 2018–19 are forecasts. This data has not been normalised like Figure 6.4 because we do not have that information at the category level.

In our April 2015 revenue decision, we found that Ausgrid had high labour costs because it had too many staff and had engaged permanent staff in preference to contractors for the 2009–14 period of transitory capex work.[65] These staff became stranded labour due to the restrictions on involuntary redundancies imposed by Ausgrid's enterprise agreement.[66] These views were informed by a review conducted by Deloitte Access Economics.[67]

In its regulatory proposal, Ausgrid has noted that its transformation program has enabled it to downsize its workforce and improve labour productivity, and that this will allow it to reduce opex in line with our April 2015 decision while ensuring it continues to deliver safe and reliable electricity services.[68]

> Phase 1 of the transformation program was launched in 2015 and focussed on laying the foundations for our future success. This was achieved through a series of initiatives to 'right-size' our workforce and increase efficiency and productivity in the field, in order to deliver sustainable reductions in our cost base without compromising safety or reliability.
>
> We introduced phase 2 of our transformation program in 2017 to drive further efficiency and operational effectiveness and to help us meet the AER's opex forecast in order to provide a stable and sound cost base for the future. We implemented additional transformation initiatives to further reduce the size of our workforce, improve the efficiency of our capital investments, improve labour productivity, increase blended delivery, drive efficient network support costs, and streamline back-office operations. We also negotiated a new competitive enterprise agreement, implemented a new management structure and invested in our key capabilities to ensure that the significant cost reductions we have achieved are sustainably embedded within our cost base moving forward.

Our category analysis shows that Ausgrid has incurred significant non-recurrent transition costs over the current period in implementing the transformation program to achieve these efficiencies (including redundancy, stranded labour and career transition program costs). Figure 6.5 shows Ausgrid's actual transition costs from 2012–13 to 2016–17 and forecast transition costs for 2017–18 and 2018–19. Ausgrid incurred $127.2 million in transition costs in 2014–15, $103.9 million in 2015–16 and $110.8 million in 2016–17 ($2018–19). These costs coincided with a reduction in Ausgrid's workforce over these three years of almost 1000 FTEs and a decline in its opex of approximately 22 per cent.[69] Ausgrid forecasts that it will reduce its transition costs to $33.5 million in 2017–18 and to $2.7 million by 2018–19, while maintaining the cost savings achieved in other opex categories.

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[65] AER, *Final Decision Ausgrid distribution determination 2015–16 to 2018 –19*, Attachment 7 – Operating Expenditure, April 2015, pp. 7-25.

[66] Ibid. The NSW ENAAT Act enacted by the NSW Parliament on 4 June 2015 after our April 2015 final decision, prohibits Ausgrid management from undertaking involuntary redundancies or amending the terms of its 2012 enterprise bargaining agreement 2015 until 1 July 2020.

[67] Deloitte Access Economics, NSW Distribution Network Service Providers Labour Analysis, November 2014, pp. i-v; Deloitte Access Economics, NSW Distribution Network Service Providers Labour Analysis: addendum to 2014 report, April 2015, pp. ii–vii.

[68] Ausgrid, *Ausgrid's Regulatory Proposal 1 July 2019 to 30 June 2024*, April 2018, p.122.

[69] Ausgrid, *Ausgrid's Regulatory Proposal 1 July 2019 to 30 June 2024*, April 2018, p.124.

This shows that while Ausgrid has incurred significant one-off transition costs in the current regulatory period, these costs have allowed Ausgrid to achieve and sustain lower costs in other opex categories (i.e. emergency services, maintenance and overheads).

Ausgrid further notes that it will be able to sustain the cost savings achieved in opex in the current period over the 2019–24 regulatory period.[70]

> For our proposed base year opex, we used our estimated underlying opex for 2017/18 [excluding all non-recurrent costs including transformation costs].
>
> …
>
> Our base year opex is in line with the AER's opex forecast for 2017/18 and is consistent with the AER's view of efficient costs, as outlined in the AER's 2015 Determination. We consider this is representative of our efficient recurrent opex requirements for 2019–24.
>
> Our proposed base year reflects the outcome of our transformation program, which has allowed us to significantly reduce our opex.

This information supports the view that the efficiencies in emergency services, maintenance and total overheads achieved in the current period are allowing Ausgrid to significantly decrease its opex and maintain this level of opex over the 2019–24 regulatory period.

Taken together, our category analysis provides additional supporting evidence that Ausgrid's proposed 2017–18 base year opex is not materially inefficient, and is consistent with a sustainable level of opex a prudent operator would require to deliver safe and reliable electricity services.

Economic benchmarking analysis

In this section, we use economic benchmarking to further test the efficiency of Ausgrid's proposed 2017–18 base year opex and its 2018–19 target opex. Benchmarking broadly refers to the practice of comparing the economic performance of a group of service providers that all provide the same service as a means of assessing their relative performance. Our 2017 annual benchmarking report includes information about the use and purpose of economic benchmarking, and details about the techniques we use to benchmark the efficiency of DNSPs in the NEM.[71]

The benchmarking results indicate that Ausgrid's 2017–18 base year opex and its 2018–19 target opex are not materially inefficient. This provides further evidence that Ausgrid's proposed base year reflects a reasonable estimate of the prudent and

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70 Ausgrid, *Ausgrid's Regulatory Proposal 1 July 2019 to 30 June 2024*, April 2018, p. 131.

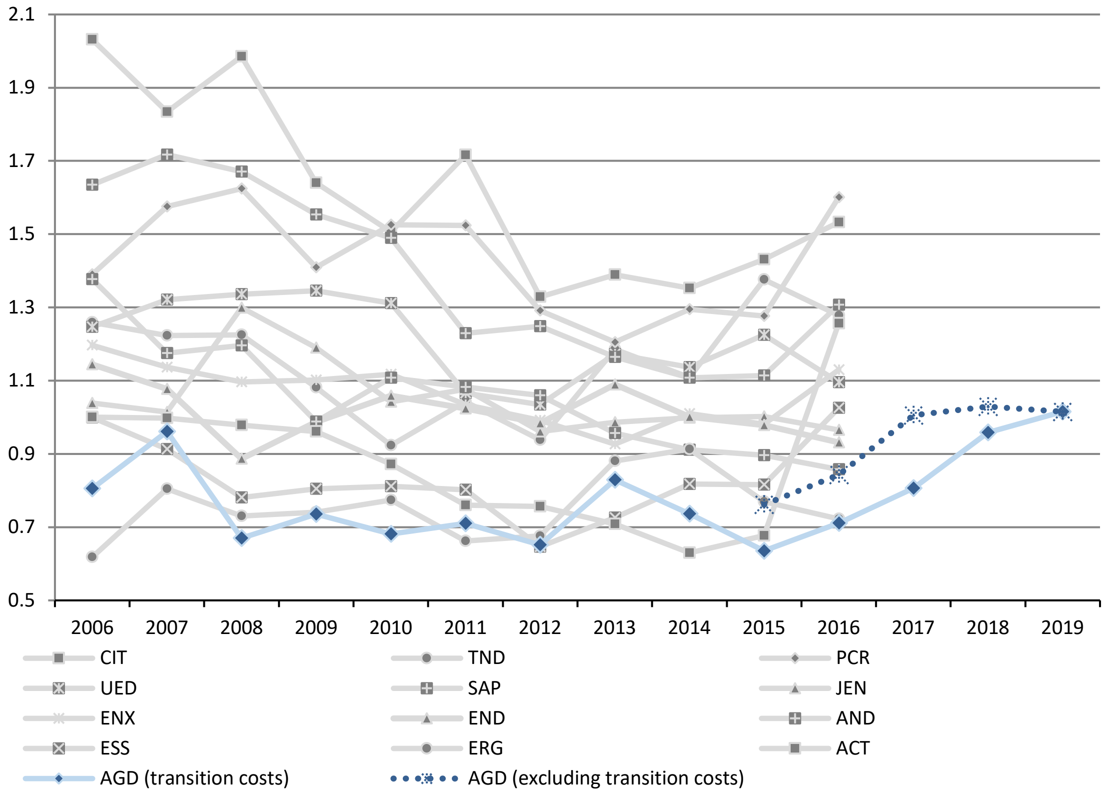
71 AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2017. Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/annual-benchmarking-report-2017

efficient level of base opex for the purposes of forecasting opex over the 2019–24 regulatory control period.

Figure 6.6 presents the results of opex multilateral partial factor productivity (MPFP), one of our primary economic benchmarking techniques. This allows for the comparison of opex productivity levels between service providers and across time.[72] When opex productivity improves, this implies there is improvements in efficiency. The chart shows Ausgrid’s own performance (the blue lines) and that of other networks (the grey lines) in the NEM over time. The unbroken blue line shows Ausgrid's opex productivity with transition costs included. The broken blue line shows its opex productivity with transition costs excluded.

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

Figure 6.6 Opex multilateral partial factor productivity[73]



Source: Economic Insights Memorandum Assessment of Ausgrid's base year opex, 6 August 2018

Note: The chart uses Ausgrid's actual opex up to 2016-17 and opex forecasts for 2017-18, and results for all other networks up until 2016 (from our 2017 published benchmarking report). Year references (i.e. 2016) refer to financial years (i.e. 2015-16). Ausgrid's transformation costs include redundancy, stranded labour and career transition program costs incurred in the current period in transitioning from a higher level of opex to a level consistent with our April 2015 decision. Transformation costs are referred to as transition costs in this decision in line with our April 2015 final decision and the Tribunal and Federal Court decisions.

This opex MPFP analysis indicates that Ausgrid has significantly improved its opex productivity over the 2014-19 regulatory control period. Figure 6.6 shows that Ausgrid's opex productivity including transition costs was lowest in 2014–15, the first year of the current regulatory period, then improves in each subsequent year up to 2018–19. Over 2015–16 and 2016–17, its opex productivity improved but remained at or below the level it achieved in 2012–13. This ranked the business as one of the least productive networks in the NEM – in 13th place in 2015–16 and 12th place in 2016–17.

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73 To understand the impact of transition costs on Ausgrid's opex efficiency over time, we have also estimated Ausgrid's opex MPFP without transition costs (the broken blue line in Figure 6.6). The results shows that transition costs have reduced Ausgrid's opex productivity over the current period, particularly in the first four years as transition costs increased total opex.

Over 2017–18 and 2018–19, the last two years of the current period, opex productivity is forecast to increase significantly – by 19 per cent and 6 per cent, respectively. This represents a significant improvement relative to its own 2012–13 level. It would also be an improvement relative to other network businesses as measured in 2015–16 – lifting Ausgrid's ranking to 9th place in 2018–19.

As Ausgrid's proposed base year opex excludes transition cost, we have also estimated Ausgrid's opex MPFP without transition costs (the broken blue line in Figure 6.6). The results show that Ausgrid's opex productivity is higher in each of the first four years of the current period when transition costs are removed. It also shows that Ausgrid's proposed 2017–18 base year opex (its target opex less transition costs) represents a significant improvement in its opex productivity relative to itself in 2012–13 and that of other businesses in 2015–16.

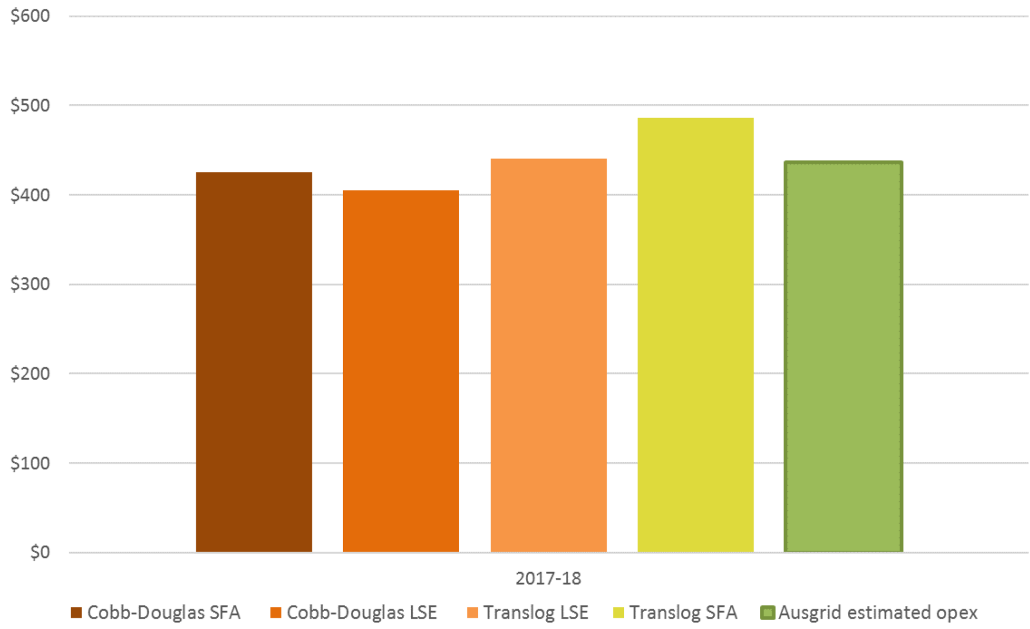
These results indicate that Ausgrid's proposed 2017–18 base year is not materially inefficient compared to its NEM peers.

We further examine the efficiency of Ausgrid's 2017–18 opex using the results of our econometric modelling. Among other things, our econometric models produce average opex efficiency scores for distributors across the 2011–17 period.[74] We use these results to estimate the 2017–18 costs of a benchmark service provider operating in Ausgrid's circumstances, and compare this to Ausgrid's proposed 2017–18 base year opex. Where Ausgrid's proposed opex is similar to, or below the estimated opex of a benchmark service operator, this gives us confidence that Ausgrid's opex is not materially inefficient.

Figure 6.7 presents this range of estimated opex from each of our four econometric models, and compares this to Ausgrid's estimated opex in 2017–18. This shows that Ausgrid's estimated opex in 2017–18 is slightly below the average opex from our four models. This suggests that Ausgrid's proposed opex in 2017–18 is not materially inefficient when compared to its peers. This is consistent with our observations of Ausgrid's opex MPFP.

[74] We have used the 2011–17 period because the data across this six year period provides for statistically robust benchmarking results and also provides a relatively current estimate of opex efficiency. We note it may take some time for improvements in efficiency by previously poor performing distributors to be reflected in the efficiency scores. For more detail, please see our 2018 annual benchmarking report for distribution service providers that we will publish by the end of November 2018.

Figure 6.7 Estimated benchmark opex and Ausgrid's estimated actual opex in 2017–18 ($million, $2018–19)



Source: AER analysis

To derive our estimates of opex of a benchmark service operator as shown in Figure 6.7, we follow the following steps for each of the four sets of econometric modelling:

- We first average Ausgrid's actual opex over the 2011–17 period.
- We then compare Ausgrid's efficiency score over 2011–17, against a benchmark comparison score of 0.75. This reflects the upper quartile of possible efficiency scores, 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.[75]
- We then adjust the benchmark comparison point for potential differences in operating environment factors (OEFs) between Ausgrid and the reference firms.[76] For the purposes of this decision, we have chosen to adopt the OEFs we applied in our April 2015 decision. This is a conservative estimate of the impact of OEFs as it accounts for both material and immaterial factors.[77]

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75 See AER, *Ausgrid Final Decision 2015-19, Attachment 7 Operating Expenditure*, April 2015, p. 7-276

76 Operating environment factors (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 DNSP. For the purpose of this decision, we have not updated the OEF adjustment made relative to the chosen benchmark reference group from our April 2015 decision.

77 In October 2018, we published a report from our consultants Sapere Research Group and Merz Consulting (Sapere-Merz) that reviewed material differences in operating environments in the NEM. The report identified a limited number of OEFs that materially affect the costs of each DNSP in the NEM. However, Sapere-Merz

- Where Ausgrid's efficiency score is below the adjusted benchmark comparison score, we adjust Ausgrid's average level of opex over 2011–17 by the difference between the two efficiency scores. This results in an estimate of period-average opex that we consider is not materially inefficient at the midpoint of 2011-17 period.
- We then roll forward this period-average opex estimate to a 2017–18 base year using the rate of change. This results in an estimate of opex that we consider is not materially inefficient in 2017–18.

These calculations are set out in a spreadsheet that we have published alongside this draft decision.

Ausgrid's proposal includes additional benchmarking analysis which it says supports the efficiency of its proposed base year:[78]

> The analysis and comparisons … show that the AER and our customers can have confidence that our transformation program has achieved levels of opex that are consistent with best practice in our industry, promoting our objective of keeping network bills affordable without compromising network safety or reliability.

Base opex adjustments

Cost categories may be added to, or excluded from, base opex under various circumstances.[79] For instance, if a cost to be incurred in a future regulatory period has not previously been accounted for in a network's historical opex, we may add this cost to the base year. Not including it may result in a total opex forecast that does not reflect the actual operating costs of the business and is inconsistent with the opex criteria.

Ausgrid proposed an upward adjustment to its proposed base year opex of $5.4 million ($2018–19) to account for the change to the classification of emergency recoverable works (ERW costs).[80]

As noted in the Final Framework Approach July 2017,[81] for the beginning of the 2019–24 regulatory control period, emergency recoverable works (ERWs) will be subsumed into the common distribution services group and classified as a direct control and standard control service.[82]

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acknowledged that its analysis was preliminary and could be improved through better data. We intend to consult further with the distribution industry to further refine the assessment and quantification of OEFs.

78 Ausgrid's *Regulatory proposal 2019-24, Attachment 6.01: Ausgrid's Operating Expenditure*, April 2018, p.15.

79 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 22.

80 Ausgrid, *Ausgrid's Regulatory Proposal 1 July 2019 to 30 June 2024*, Attachment 6.0, April 2018, p. 26.

81 Framework and approach Ausgrid, Endeavour Energy and Essential Energy Regulatory control period commencing 1 July 2019-July 2017, p.22.

82 We define emergency recoverable works 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

Although we propose classifying 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 emergency recoverable works. 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.

Ausgrid's proposed $5.4 million ($2018–19) adjustment represent an estimation of its annual unrecovered ERW costs. This is based on the annual cost of repairing third party damage to its network (calculated using average historic actual costs) less the revenue recovered from parties found liable for causing the damage (calculated using average historic receipts from liable parties).

Ausgrid notes that this base adjustment is justified as:[83]

> In 2017/18, ERW was an unregulated service, however, consistent with the AER's Final [Framework and Approach] paper, this service will become a regulated distribution service from the beginning of the next regulatory period. In previous determinations, we adjusted the base year costs to reflect changes in the service classification. We have followed the same approach here.

Ausgrid's approach of applying an upward adjustment to its base year opex for unrecovered ERW costs is premised on these costs not having been attributed to standard control opex historically and so not already being reflected in its proposed 2017–18 base opex. We have had limited visibility on how Ausgrid has allocated these ERW costs historically and in its base year.

In response to an AER information request, Ausgrid has stated that over the 2014–19 regulatory period, ERW costs have been accounted for as unregulated opex and recoveries of ERW costs from third parties have been accounted for as unregulated revenue.[84] Ausgrid further states that unrecovered ERW costs have been accounted for as an unregulated line of business financial loss. Consequently, Ausgrid argues that unrecovered ERW costs are not included in its historic opex and the upward adjustment to its base opex is required. Ausgrid did not provide any specific financial information to support its statements.

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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.

[83] Ausgrid's Regulatory Proposal – Attachment 6.01 – Ausgrid's proposed operating expenditure, p. 26.

[84] AER Information request #41, Ausgrid email 19 September 2018.

To make a draft determination on these costs, we need to be satisfied that the costs of ERW have not already been reported by Ausgrid in its base year opex. We currently do not have sufficient information to make a determination on this based on the information provided to us by Ausgrid to date. Consequently we have not included the adjustment to Ausgrid's base year opex in our opex forecast. We invite further information from Ausgrid to better understand how these costs and revenues have been accounted for over the 2014–19 regulatory period to allow consideration of the issue in our final decision.

We also made an adjustment to Ausgrid's revealed 2017–18 opex for movements in provisions. This ensures we base our alternative estimate on the actual costs incurred by the business, and not provisions the business set aside for liabilities it has yet to pay out. Ausgrid will report its actual movements in provisions for 2017–18 when it submits its regulatory accounts in October 2018. We will update this estimate in our final decision.

Rolling forward base year opex

Under the base-trend-step approach, the starting point to forecast opex in the next regulatory control period is opex in the final year of the current period, 2018–19. However, we do not know this level of opex at the time of making our regulatory decision. We typically estimate final year opex using a well-defined formula.[85]

We have not applied the Guideline formula to estimate opex in 2018–19. Instead, we have rolled forward Ausgrid's estimate of 2017–18 opex, which we are satisfied is not materially inefficient, by escalating it by the rate of change. We consider this approach reasonable because:

- The Guideline forecast opex formula and the EBSS are designed to work together. When the EBSS is implemented, the estimate of final year opex used to forecast opex in the next regulatory control period should be the same as that used to forecast the EBSS carryover because the base-trend-step approach and the EBSS are intrinsically related.[86] This consistency ensures that a distributor 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. However, Ausgrid was not subject to the EBSS over the 2014–19 period.[87] Therefore, for this determination,

[85] As set out in our Guideline, the best estimate of final year opex is our preferred starting point to forecast opex. We calculate it by: (1) determining the underspend from the base year (that is, the difference between opex allowance and opex incurred in the base year); (2) subtracting this base year underspend from opex allowance in the final year of the current regulatory control period (2018–19); (3) adding back any non-recurrent efficiency gains realised in the base year. For more details see: AER, *Expenditure Forecast Assessment Guideline for Electricity distribution*, November 2013, pp. 22–23.

[86] The NER explicitly require us to have regard to whether an opex forecast is consistent with any incentive schemes that apply to a network services provider. NER, clause 6.5.6(e)(8).

[87] AER, *Final decision Ausgrid distribution determination, Attachment 9, Efficiency benefit sharing scheme,* April 2015.

consistency between the base-trend-step forecasting approach and the EBSS is not relevant and we can estimate final year opex using an alternative approach.

- The alternative approach we have applied reasonably accounts for key drivers of opex growth (price, output and productivity growth) between the base year (2017–18), and the final year of the current period (2018–19).[88]

In contrast, Ausgrid calculated its estimated actual opex for 2018–19 by applying the Guideline formula. The net impact of implementing our approach, rather than Ausgrid's approach, is a decrease in opex of $15.0 million ($2018–19) over the 2019–24 regulatory control period.

6.4.2 Rate of change

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

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

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

We have forecast an average annual rate of change of 1.3 per cent, compared to Ausgrid's forecast of 1.7 per cent. The reasons for our forecast, and its difference compared to Ausgrid's forecast, are set out below.

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

Further, we have received feedback from various parties suggesting we review this aspect of the rate of change.[89] Our review may change our approach to forecasting productivity going forward. As part of this review, we will consult with all distributors

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88 AER, *Expenditure Forecast Assessment Guideline – Final Explanatory Statement*, November 2013, p. 61.

89 AGL - *Submission on Ausgrid 2019–24 regulatory proposal*, 14 September 2018, p.4; CCP10 - *Submission on Ausgrid 2019–24 regulatory proposal*, 8 August 2019, pp.30–31; ECA - *Submission on Ausgrid 2019–24 regulatory proposal*, 14 August 2018, p.13; EUAA - *Submission on Ausgrid 2019–24 regulatory proposal, 10 August 2018*, p.11.

and any other interested stakeholders.[90] Stakeholders will be given multiple opportunities to engage in the review and provide us with their views.

Our final decision for Ausgrid will take the outcome of this review into consideration.

Forecast price growth

We have included forecast real average annual price growth of 0.6 per cent in developing our alternative opex estimate. This increases opex from the base year by $32.4 million ($2018–19). In contrast, Ausgrid forecast annual price growth of 0.8 per cent.

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

- To forecast labour price growth, we have used the average forecast growth in the wage price index (WPI) for the New South Wales utilities industry by our consultant Deloitte Access Economics and Ausgrid's consultant, BIS Oxford Economics.[91] In contrast, Ausgrid applied a single WPI forecast by BIS Oxford Economics.
- To forecast non-labour price growth, we, like Ausgrid, have applied the forecast change in CPI.[92]

We and Ausgrid have applied the same weights to account for the proportion of opex that is labour and the proportion that is non-labour (59.7:40.3). Our reasons for adopting these weights are set out in our 2017 Economic Benchmarking report.[93]

Forecast output growth

We have included forecast average annual output growth of 0.7 per cent in developing our alternative estimate of forecast opex. This increased our alternative estimate by $49.1 million ($2018–19). Our output growth forecast is an average of the output growth rates forecast using the specification and weights from the four models presented in our 2017 annual benchmarking report. These models are:[94]

- Opex multilateral partial factor productivity (MPFP)
- Cobb Douglas stochastic frontier analysis (SFACD)
- Cobb Douglas least squares estimation (LSECD)

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

[91] Deloitte Access Economics, *Labour Price Growth Forecasts Prepared for the Australian Energy Regulator*, 19 July 2018, Table vii, p. xiv; Ausgrid - *RIN09 - BIS Oxford - Cost escalation report*, September 2017.

[92] Ausgrid, *Regulatory proposal*, April 2018, p.132.

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

[94] Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report*, 31 October 2017, p.1 and pp.18–20.This is also consistent with the weights in our 2018 annual benchmarking report, which will be published before the end of November 2018.

- Translog least squares estimation (LSETLG).

Table 6.4 shows the output specification and weights from each model as reflected in the 2017 annual benchmarking report.[95]

Table 6.4 Output specification and weights derived from economic benchmarking models

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

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

We have forecast our year-on-year output growth by:

- Calculating four model-specific output growth rates, each as a weighted average growth in specified outputs.[96] For example, the output growth rate based on the MPFP model is a weighted average of growth in customer numbers, circuit length, ratcheted maximum demand and energy throughput; and that based on SFACD model is a weighted average of growth in customer numbers, circuit length and ratcheted maximum demand.
- Calculating the average of four model specific output growth rates.

This is a refinement of our previous approach, which only used the output weights from a single econometric model (the SFACD model).[97] In contrast, Ausgrid applied our previous approach in forecasting output growth.[98]

CCP10 recently raised concerns about the weight applied to customer numbers under our previous approach. In its submission on Evoenergy's regulatory proposal, CCP10 stated that trend customer growth accounts for a significant part of Evoenergy's output growth. It noted that this outcome flows from our underlying econometric model.

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95 We will release our 2018 annual benchmarking report before the end of November 2018, which contains updated output weights. Stakeholders will have the opportunity to comment on the benchmarking results, including these weights, before the report is finalised. In our final decision, we will update the output weights we apply in our opex forecast to reflect the finalised 2018 annual benchmarking report. Ausgrid will also have an opportunity to update its output weights in its revised proposal.

96 We adopted Ausgrid's forecasts growth in customer numbers, circuit line length, energy throughput, and ratcheted maximum demand.

97 This previous approach was used to inform our alternative forecast in our April 2015 decision.

98 Ausgrid, Attachment 6.02, *Opex model*, April 2018.

CCP10 encouraged us to test whether our output growth rates are reasonable, and whether too much weight has been allocated to customer numbers when we forecast output growth.[99]

We have reviewed the output weights derived from the four models presented in our economic benchmarking reports over the period 2014–17. Our review shows that the weight of customer numbers derived from the SFACD model is relatively high and it has increased over time. The customer numbers weight does not increase as much in the other econometric models (LSECD and LSETLG).[100]

Our refined approach, which uses an average of the output weights from the four models, helps to address concerns raised by the Australian Competition Tribunal (the Tribunal) in its merits review of our 2015 decision for NSW electricity determinations. The Tribunal raised concerns about our reliance on a single model and in remitting the NSW decisions directed us to use a broader range of modelling and benchmarking.[101]

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

Full details of our refined approach to forecast output growth are set out in our opex model, which is available on our website.

Forecast productivity growth

For the draft decision, we have forecast zero productivity growth in our alternative opex forecast. This is consistent with Ausgrid's regulatory proposal, and our standard approach to forecasting productivity.[102]

In response to Ausgrid's proposal, Origin, CCP10, AGL Energy, ECA, PIAC and EUAA stated the AER should reconsider our standard approach of forecasting zero productivity growth.[103] They consider that firms in competitive markets should expect positive productivity improvements.

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

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

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

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

103 AGL - *Submission on Ausgrid 2019–24 regulatory proposal*, 14 September 2018, p.4; CCP10 - *Submission on Ausgrid 2019–24 regulatory proposal*, 8 August 2019, pp.30–31; ECA - *Submission on Ausgrid 2019–24 regulatory*

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

6.4.3 Step changes

We add (or subtract) step changes for any costs are not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria.[104] A step change must reflect prudent and efficient cost increases or decreases associated with new regulatory obligations, or a prudent and efficient substitution between capex and opex.

Ausgrid has proposed two step changes to base opex totalling $29.1 million ($2018–19) or 1.2 per cent of its total opex forecast. These step changes are:

- $26.1 million ($2018–19) to fund demand management to allow the deferral of $68.6 million in capex beyond the 2019–24 period (the deferred capex relates to one augex and six repex projects)
- $3.0 million ($2018–19) to fund a pricing reform acceptance research project that would inform Ausgrid's transition to more cost reflective pricing as required by the AEMC’s 2017 rule change for Distribution Network Pricing Arrangements.

We have included $8.5 million in Ausgrid's base opex for demand management to defer $29.0 million in repex on the Lidcombe, Mascot and St. Ives switchgear replacement projects beyond the 2019–24 period. We consider these three projects reflect a prudent and efficient capex opex trade-off.

We have not accepted $17.7 million in demand management to defer $39.6 million in capex on the Concord and Leightonfield switchgear projects, the Haymarket-Pyrmont 132kV feeder replacement project and Ausgrid's HV augmentation program. Based on the information provided by Ausgrid, we do not consider that these projects reflect a prudent and efficient capex opex trade-off. We invite further information from Ausgrid on these four demand management proposals for further consideration in our final decision.

We have not included Ausgrid's proposed pricing reform acceptance research project of $3.0 million ($2018–19) as we consider this type of activity is part of a distributor's standard business activities and is accommodated for within its existing costs and base year opex. Further, we do not consider this represents a cost increase associated with a new regulatory obligation.

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proposal, 14 August 2018, p.13; EUAA - *Submission on Ausgrid 2019–24 regulatory proposal, 10 August 2018*, p.11; PIAC - *submission in response to NSW DNSPs' AER issues paper*, 8 August 2018, p.23.

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

Demand management to defer repex and augex projects

Ausgrid has proposed to incur $26.1 million ($2018–19) in demand management opex to allow it to defer $68.6 million in capex projects beyond the 2019–24 regulatory control period.[105] The seven capex projects include the use of demand management to defer, beyond the 2019-24 regulatory period:

- repex to replace Lidcombe, Mascot, St. Ives, Concord and Leightonfield switchgear
- repex to replace the Haymarket-Pyrmont 132kV feeder
- augex that would otherwise be incurred as part of Ausgrid's high voltage augmentation program.[106]

Our draft decision includes a step change of $8.5 million ($2018–19) for demand management to defer $29.0 million ($2018–19) in repex beyond the 2019–24 period. We did not include $17.7 million ($2018–19) of Ausgrid's proposed demand management to defer $39.6 million in augex and repex beyond the 2019–24 period.

Our assessment of this step change is based on Ausgrid's own assessment undertaken for each of the seven proposed uses of demand management to defer capex. Ausgrid describes the assessment approach it has used to select demand management to defer repex in its proposal:[107]

> We estimate proposed DM expenditure on a case-by-case basis for larger projects at sub transmission level, and on a modelled basis for the smaller projects at 11 kV level. For individual projects, a cost benefit assessment is used to assess the cost effectiveness of non-network solutions in comparison with network options over a 20 year time horizon.'
>
> 'For each project assessment, DM options were included alongside supply side options in developing the suite of potential solutions to meet the relevant network needs. We assess the net present value of each competing network and non-network option over a 20 year time horizon to identify the preferred solution. Where a non-network option is found to offer an equivalent (or higher) net present value, it is preferred. The potential for deferral of all capital projects above $1 million are considered in this process.'
>
> 'As part of the cost benefit analysis, assumptions are made about the likely scale of demand reductions possible and estimated costs of a non-network solution. These assumptions are based on previous experience with delivery of DM projects, submissions to non-network.

105 Ausgrid's Regulatory Proposal – Attachment 6.01 – Ausgrid's proposed operating expenditure, pp. 36-42.
106 Ibid.
107 Ibid. p. 37.

Ausgrid also described the assessment approach it has used to select demand management to defer augex in its proposal:[108]

> For the HV augmentation program, we have estimated the impact of DM on our projected program expenditure. While network reinforcement programs are traditionally not a significant source of projects which offer a material volume of viable DM options, we expect this to change, given the heightened focus within industry as a result of the Demand Management Incentive Scheme and programs driven by AEMO and the Australian Renewable Energy Agency.
>
> Ausgrid undertook a top-down assessment of the viability of DM as an option for the HV augmentation program (see Attachment 6.05 for the cost-benefit analysis). This assessment was based on our estimates of the viability and costs of DM as an option in this investment category. These estimates are based on previous experience with delivery of DM projects, submissions to non-network options reports from non-network solutions providers and lessons learned from DM trials by Ausgrid and other networks in Australia.

PIAC, the City of Sydney and Origin gave in-principle support to the use of demand management in submissions to Ausgrid's proposal.[109] PIAC stated it supports Ausgrid's demand management step change if the AER deemed the trade-off efficient.[110]

We have included demand management opex in this draft decision to fund the deferral of repex for the Lidcombe, Mascot, St. Ives switchgear projects. This results in an increase in opex of $8.5 million ($2018–19) over the current period for demand management to defer $29.0 million ($2018–19) in repex beyond the 2019–24 period. For each of these projects, Ausgrid's analysis shows the use of demand management provides a greater net benefit compared with the network (repex) option.[111] This supports the view that these uses of demand management represent a prudent and efficient capex opex trade-off.

We have not included demand management opex to fund the deferral of repex for Ausgrid's proposed Concord, Leightonfield switchgear and Haymarket-Pyrmont 132kV feeder replacement projects. This results in $12.7 million of demand management opex not being included in our opex forecast to defer of $21.7 million in repex beyond the 2019–24 period. In each case, Ausgrid's analysis shows the use of demand

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108 Ibid. p. 42.

109 PIAC - *submission in response to NSW DNSPs' AER issues paper*, 8 August 2018, p.25; Origin - *submission on Ausgrid 2019–24 regulatory proposal*, 8 August 2018, p.2; City of Sydney - *submission on Ausgrid 2019–24 regulatory proposal*, 9 August 2018, pp. 1-2.

110 PIAC - submission in response to NSW DNSPs' AER issues paper, 8 August 2018, p.25.

111 Information request 40, 18 September 2018, Ausgrid Attachment 6.05 Demand management cost benefit assessment.

management provides a lower net benefit compared with the network (repex) option.[112] This supports the view that these uses of demand management do not represent a prudent and efficient capex opex trade-off.

Apart from the Mascot switchgear project, the difference in net benefits between the network and non-network options are typically small (less than $1 million ($2018–19) based on a net benefit assessment over 20 years). We seek further information from Ausgrid on the factors affecting the sensitivity of the net benefit assessments to allow further consideration of this issue in the final decision.

Our draft decision does not include $5.0 million in demand management opex to defer $17.9 million in augex for high voltage augmentation projects beyond the 2019–24 period. Ausgrid's proposal did not include a net benefit assessment of this project. We are seeking further information from Ausgrid on the net benefits of the demand management and network options in this case to allow further consideration of this issue in our final decision.

Our capex forecast has had regard to the impact of the above assessments. Further details on our capex assessment are set out at Attachment 5.

Pricing reform acceptance research project

Ausgrid has proposed a step change of $1.5 million ($2018–19) in both 2019–20 and 2020–21 ($3 million in total for the 2019–24 regulatory period) to meet costs it states it must incur to address an AEMC rule change for Distribution Network Pricing Arrangements.[113]

Ausgrid notes:[114]

> 'The driver of this step change is a change to the regulatory obligations for setting network prices, which requires us to transition to cost-reflective network prices and improve the transparency of our pricing information and consult with retailers and customers on the design of network prices. Under this rule change, network prices based on the new pricing objective and pricing principles will be gradually phased in from 2017.'

The AEMC rule change was made on 27 November 2014 and requires network businesses to set prices that reflect the efficient cost of providing network services to individual consumers.[115] The rule change included processes and timeframes for setting network prices, consulting with consumers and retailers, and also noted:[116]

112 Ibid.

113 Ausgrid's Regulatory Proposal – Attachment 6.01 – Ausgrid's proposed operating expenditure, pp. 33-36.

114 Ausgrid's Regulatory Proposal April 2018, p.136.

115 AEMC, Distribution Network Pricing Arrangements, see: https://www.aemc.gov.au/rule-changes/distribution-network-pricing-arrangements.

116 Ibid.

> 'Network prices based on the new pricing objective and pricing principles will be gradually phased in from 2017. Under the final rule, network businesses will need to submit their initial tariff structure statement to the AER by late 2015.'

Various stakeholder submissions did not support Ausgrid's proposed tariff research step change. The CCP10, EUAA and PIAC have questioned Ausgrid's justification for proposing the research project as a step change.[117] PIAC notes that while it considers the Rules require a rapid transition to cost reflective network tariffs, the Rules do not require Ausgrid's proposed research project.[118]

We have not included $3.0 million ($2018–19) to fund the pricing reform acceptance research project in our opex forecast. A step change of this type must reflect prudent and efficient cost increases associated with new regulatory obligations that have not applied to Ausgrid's 2017–18 base year.[119] The AEMC rule change was finalised in 2014 and as such cannot be considered a new regulatory obligation for the 2019–24 regulatory control period. We consider this type of activity falls within the range of a distributor's standard business activities and is accommodated for within Ausgrid's existing costs and base year opex.

6.4.4 Category specific forecasts

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

Debt raising costs

We have included debt raising cost of $38.7 million ($2018–19) in our alternative opex forecast. Debt raising costs are transaction costs incurred each time a business raises or refinances debt. Our preferred approach is to forecast debt raising costs using a benchmarking approach rather than a service provider's actual costs in a single year. This provides for consistency with the forecast of the cost of debt in the rate of return building block. We discuss this in attachment 3 of this determination.

6.4.5 Assessment of opex factors under NER

Opex factor	Consideration
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.[120]	There are two elements to this factor. First, we must have regard to the most recent annual benchmarking report. Second, we must have regard to the benchmark operating expenditure that would be incurred by an efficient distribution network service provider over the period. The annual benchmarking report is intended to provide an annual snapshot of the relative efficiency of each service

[117] CCP10 - submission on Ausgrid 2019–24 regulatory proposal, 8 August 2018, p.26, EUAA - submission on Ausgrid 2019–24 regulatory proposal, 10 August 2018, p. 13, PIAC - submission in response to NSW DNSPs' AER issues paper, 8 August 2018, p.25.

[118] PIAC - submission in response to NSW DNSPs' AER issues paper, 8 August 2018, p.25.

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

[120] NER, cl.6.5.6(e)(4).

Opex factor	Consideration
	provider. We have estimated the benchmark opex that an efficient service provider would require over the forecast period and have compared our estimate with Ausgrid's proposal over the relevant regulatory control period. In doing this we relied on approaches set out in our most recent benchmarking report and additional benchmarking analysis commissioned for this reset.
The actual and expected operating expenditure of the Distribution Network Service Provider during any proceeding regulatory control periods.[121]	Our forecasting approach uses Ausgrid's estimated opex in 2017–18 less transition costs as the starting point. We have examined Ausgrid's actual expenditure to form a view about whether or not its revealed expenditure is sufficiently efficient to rely on it as the basis for forecasting required opex in the forthcoming period.
The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.[122]	We understand the intention of this particular factor is to require us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers.[123] CCP10 stated Ausgrid provided some excellent engagement with consumers, but this was undone by its proposal not reflecting consumer input as strongly as it should have.[124] PIAC noted Ausgrid's customer engagement had improved from last period, but stated Ausgrid has still not shown a high level of commitment to customer engagement. PIAC also noted there was some evidence that Ausgrid's engagement has translated into a better proposal.[125] The ECA agreed with PIAC's assessment of Ausgrid's engagement with consumers. It stated Ausgrid made some improvement on the way it engaged with consumers and other stakeholders compared to the previous regulatory period.[126] Based on the information provided by Ausgrid in its proposal and the various stakeholder submissions, we consider Ausgrid's opex forecast addresses some concerns of electricity consumers.
The relative prices of capital and operating inputs[127]	We adopted price escalation factors that account for the relative prices of opex and capex inputs. We have also considered capex/opex trade-offs in considering Ausgrid's proposed demand management step change. One reason we will include a step change in our alternative opex forecast is if the service provider proposes a capex/opex trade-off. We consider the relative expense of capex and opex solutions in considering such a trade-off.
The substitution possibilities between operating and	As noted above we considered capex/opex trade-offs in

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

[122] NER, cl.6.5.6(e)(5A).

[123] AEMC, *Rule Determination*, 29 November 2012, pp. 101, 115.

[124] CCP10 - *Submission on Ausgrid 2019–24 regulatory proposal*, 8 August 2018, p.6.

[125] PIAC - A*ttachment A - Consumer engagement evaluation*, 8 August 2018, p.18.

[126] ECA - *Submission on Ausgrid 2019–24 regulatory proposal*, 14 August 2018, p.6

[127] NER, cl.6.5.6(e)(6).

Opex factor	Consideration
capital expenditure.[128]	considering Ausgrid's demand management step change. We considered the substitution possibilities in considering this step change. In reaching our decision to accept part of Ausgrid's proposed step change, we noted that this opex was an efficient solution that deferred capex from the 2019–24 regulatory control period.
Whether the operating expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.[129]	We normally apply the EBSS in conjunction with our revealed cost forecasting approach. Ausgrid did not have an EBSS in place over the 2014–19 regulatory control period. We have reapplied the EBSS for the 2019–24 period.
The extent the operating expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.[130]	Some of our techniques assess the total expenditure efficiency of service providers and some assess the total opex efficiency. A service provider which uses related party providers could be efficient or it could be inefficient. Likewise, for a service provider who does not use related party providers. If a service provider is inefficient, we adjust their total forecast opex proposal, regardless of their arrangements with related providers.
Whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).[131]	This factor is generally only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). We did not identify any contingent projects in reaching our draft decision.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network options.[132]	Ausgrid has proposed expenditure for non-network alternatives within its demand management opex step-change proposal. As noted above, we have included three of the proposed uses of demand management in this draft decision.
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s).[133]	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. Ausgrid did not submit any RIT-D project for its distribution network.

128 NER, cl.6.5.6(e)(7).

129 NER, cl.6.5.6.(e)(8).

130 NER, cl.6.5.6(e)(10).

131 NER, cl.6.5.6(e)(9A).

132 NER, cl.6.5.6(e)(10).

133 NER, cl.6.5.6(e)(11).