# FINAL DECISION
# ActewAGL Distribution
# Access Arrangement
# 2016 to 2021

# Attachment 7 – Operating expenditure

May 2016

AUSTRALIAN ENERGY REGULATOR

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# Note

This attachment forms part of the AER's final decision on the access arrangement for ActewAGL Distribution for 2016–21. It should be read with all other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 - Services covered by the access arrangement

Attachment 2 - Capital base

Attachment 3 - Rate of return

Attachment 4 - Value of imputation credits

Attachment 5 - Regulatory depreciation

Attachment 6 - Capital expenditure

Attachment 7 - Operating expenditure

Attachment 8 - Corporate income tax

Attachment 9 - Efficiency carryover mechanism

Attachment 10 - Reference tariff setting

Attachment 11 - Reference tariff variation mechanism

Attachment 12 - Non-tariff components

Attachment 13 - Demand

# Contents

Note ..........7-2

Contents ..........7-3

Shortened forms ..........7-4

7 Operating expenditure ..........7-6

7.1 Final decision ..........7-6

7.2 ActewAGL's revised proposal ..........7-8

7.3 AER's assessment approach ..........7-9

7.3.1 Building an alternative estimate of total forecast opex .......... 7-10

7.3.2 Interrelationships .......... 7-11

7.4 Reasons for final decision ..........7-11

7.4.1 Forecasting method .......... 7-11

7.4.2 Base year opex .......... 7-11

7.4.3 Rate of change .......... 7-16

7.4.4 Step changes .......... 7-20

7.4.5 Category specific changes .......... 7-30

# Shortened forms

| Shortened form | Extended form |
|---|---|
| AA | Access Arrangement |
| AAI | Access Arrangement Information |
| AER | Australian Energy Regulator |
| ASA | Asset Services Agreement |
| ATO | Australian Tax Office |
| capex | capital expenditure |
| CAPM | capital asset pricing model |
| CCP | Consumer Challenge Panel |
| CMF | construction management fee |
| CPI | consumer price index |
| DAMS | Distribution Asset Management Services |
| DRP | debt risk premium |
| EBSS | Efficiency Benefit Sharing Scheme |
| ECM | Efficiency Carryover Mechanism |
| EIL | Energy Industry Levy |
| ERP | equity risk premium |
| Expenditure Guideline | Expenditure Forecast Assessment Guideline |
| gamma | value of imputation credits |
| GSL | Guaranteed Service Level |
| GTA | Gas Transport Services Agreement |
| ICRC | Independent Competition and Regulatory Commission |
| MRP | market risk premium |
| NECF | National Energy Customer Framework |
| NERL | National Energy Retail Law |
| NERR | National Energy Retail Rules |
| NGL | National Gas Law |
| NGO | National Gas Objective |
| NGR | National Gas Rules |
| NPV | net present value |
| opex | operating expenditure |

| Shortened form | Extended form |
|---|---|
| PFP | partial factor productivity |
| PPI | partial performance indicators |
| PTRM | post-tax revenue model |
| RBA | Reserve Bank of Australia |
| RFM | roll forward model |
| RIN | regulatory information notice |
| RoLR | retailer of last resort |
| RSA | Reference Service Agreement |
| RPP | revenue and pricing principles |
| SLCAPM | Sharpe-Lintner capital asset pricing model |
| STTM | Short Term Trading Market |
| TAB | tax asset base |
| UAFG | unaccounted for gas |
| UNFT | Utilities Network Facilities Tax |
| WACC | weighted average cost of capital |
| WPI | Wage Price Index |

# 7 Operating expenditure

Forecast opex is the forecast operating, maintenance and other non-capital costs incurred in the provision of gas distribution services. It includes labour costs and other non-capital costs that a prudent service provider is likely to require during an access arrangement period for the efficient operation of its network.

This attachment provides our approved opex allowance for the 2016–21 period. As our final decision includes a true-up of revenue for the interval of delay in 2015–16, we have also determined an opex allowance for 2015–16 (together with the other relevant building blocks).

## 7.1 Final decision

We are not satisfied that the forecast of total opex ActewAGL proposed complies with the opex criteria and the criteria for forecasts and estimates.[1] We therefore do not accept the forecast of opex ActewAGL included in its building block proposal.

Our opex estimate for the 2016–21 period is $156.9 million, which is 3.3 per cent lower than ActewAGL's forecast of $162.2 million. The main reason our forecast is lower than ActewAGL's is because we do not accept all its proposed step changes. Our final opex decision for 2015–16 and for the 2016–21 period is shown in Table 7.1.

### Table 7.1 Final decision on ActewAGL's total opex ($million, 2015–16)

| | 2015–16 | 2016–17 | 2017–18 | 2018–19 | 2019–20 | 2020–21 | Total (2016–21) |
|---|---|---|---|---|---|---|---|
| ActewAGL's initial proposal | n/a | 27.3 | 27.3 | 28.1 | 30.9 | 30.2 | 143.8 |
| AER draft decision | 24.7 | 26.0 | 26.1 | 26.5 | 27.1 | 27.3 | 133.0 |
| ActewAGL's revised proposal[2] | 29.7 | 31.4 | 31.0 | 31.6 | 35.0 | 34.0 | 162.2 |
| AER final decision | 28.2 | 30.5 | 30.8 | 31.4 | 32.1 | 32.1 | 156.9 |

Note: Excludes debt raising costs.

Source: AER analysis; ActewAGL Distribution Gas network Access Arrangement 2016–21 Opex model; ActewAGL Distribution - Revised 2016-21 access arrangement proposal - Appendix 7.01 Revised proposal opex model - January 2016; AER Draft Decision ActewAGL Distribution Access Arrangement 2016-21 Attachment 7 - Operating expenditure, November 2015. Numbers may not add due to rounding.

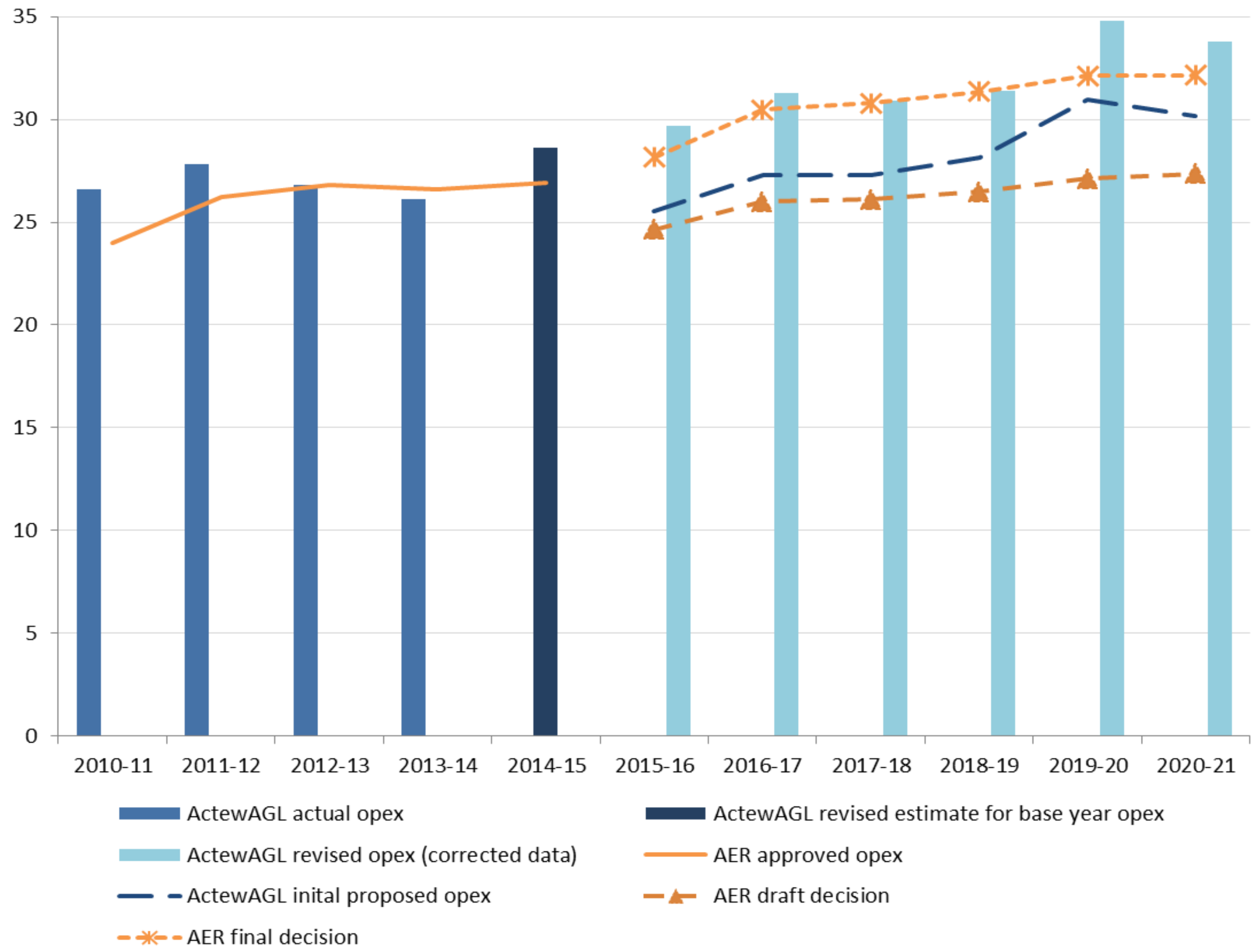
1 NGR, rr. 74, 91.

2 The opex model that ActewAGL submitted on 6 January 2016 used incorrect customer demand and customer consumption data which impacted on its forecast rate of change, Utilities Network Facilities Tax (UNFT), Unaccounted for Gas (UAG) and Energy Industry Levy (EIL). The numbers in this attachment correct for these errors and are consistent with ActewAGL's response to AER information request 44.

We have revised the access arrangement having regard to our reasons for refusing to approve ActewAGL's proposal and the further matters identified in the NGR Rule 64(2). Our revisions are reflected in the Approved Access Arrangement for ActewAGL's Gas Distribution Network in the ACT for 2016–21, which gives effect to this decision.

Figure 7.1 shows our final decision compared to ActewAGL's revised proposal, its past allowances and past actual expenditure.

### Figure 7.1 Final decision compared to ActewAGL's past and proposed opex ($ million, 2015–16)




Source: AER analysis; ActewAGL Distribution Gas network Access Arrangement 2016–21 Opex model; ActewAGL Distribution - Revised 2016-21 access arrangement proposal - Appendix 7.01 Revised proposal opex model - January 2016; AER Draft Decision ActewAGL Distribution Access Arrangement 2016-21 Attachment 7 - Operating expenditure, November 2015. Numbers may not add due to rounding.

An overview of ActewAGL's revised proposal is set out in section 7.2. The approach we use to assess ActewAGL's forecast is outlined below in section 7.3. Our reasons for our final decision are set out in section 7.4. Information on the application of the efficiency carryover mechanism to ActewAGL both in the current period and the next period can be found in Attachment 9.

## 7.2 ActewAGL’s revised proposal

ActewAGL's revised opex forecast is $162.2 million ($2015–16) over the 2016-21 access arrangement period. It comprises:

- base opex of $107.2 million ($2015–16), based on an actual (adjusted) base year opex of $21.4 million ($2015-16)
- rate of change in opex of $5.0 million ($2015–16), based on forecast input price changes, output changes and productivity change
- step changes which increase total opex by $6.3 million ($2015–16). Of the nine step changes in ActewAGL's revised proposal, two are new, three are step changes we accepted in our draft decision while the remainder are step changes we did not accept in our draft decision but have been re-proposed.
- category specific forecasts which total $43.7 million ($2015–16) for Utilities Network Facilities Tax (UNFT), Energy Industry Levy (EIL) and Unaccounted for Gas (UAG).

ActewAGL's revised opex forecast is equivalent to a 13 per cent increase from its initial proposal of $143.8 million. This increase results from a change in the way it derived its adjusted base opex. ActewAGL's revised proposal uses the AER's standard revealed cost approach and only specifically forecast costs related to UNFT, EIL and UAG. In comparison, ActewAGL's initial proposal removed a number of expenditure items from the base year it considered should be specifically forecast or treated as a step change.

We note that while ActewAGL's proposed total opex has increased, when its revised total opex and ECM carryover amounts for the 2016–21 period are combined, the net revenue impact from these elements is similar between the revised proposal and the initial proposal. This is because of the interrelationship between the single year revealed cost forecasting approach for determining total opex and the opex efficiency carryover mechanism. While a higher base opex results in a higher total opex, it also results in a lower (negative) carryover amount from the application of the efficiency carryover mechanism.

Table 7.2 shows that the net revenue impact (combination of opex and ECM carryover amounts) of ActewAGL's initial and revised proposals is similar.

### Table 7.2 Net revenue impact of ActewAGL's initial and revised proposals ($million, 2015–16)

| | Total opex 2016-21 period | Carryover from application of the ECM | Net revenue impact |
|---|---|---|---|
| ActewAGL's initial proposal | 143.8 | 11.2 | 155.0 |
| ActewAGL's revised proposal | 162.2 | -5.9 | 156.3 |

Source: ActewAGL Distribution Gas network Access Arrangement 2016–21 Opex model; ActewAGL Distribution - Revised 2016-21 access arrangement proposal - Appendix 7.01 Revised proposal opex model - January 2016. Numbers may not add due to rounding.

## 7.3 AER's assessment approach

We decide whether or not to accept a service provider's total forecast opex proposal. We approve the service provider's forecast opex if we are satisfied that it is consistent with the criteria governing operating expenditure (the opex criteria).[3]

> 91. Criteria governing operating expenditure
>
> (1) Operating expenditure must be as such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

In determining whether forecast opex is consistent with the opex criteria we have regard to the criteria for forecasts and estimates.

> 74. Forecasts and estimates
>
> (1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate
>
> (2) A forecast or estimate:
>
> (a) must be arrived at on a reasonable basis; and
>
> (b) must represent the best forecast or estimate possible in the circumstances.

To assist us in forming a view on whether a service provider's proposed opex complies with the opex criteria we compare the service provider's total forecast opex with our alternative estimate of total opex.

Our estimate is unlikely to exactly match the service provider's forecast because the service provider may adopt a different forecasting method to us. However, if the service provider's inputs and assumptions are reasonable, its method should produce a forecast consistent with our estimate. Accordingly, part of our approach is to assess

3 Also see NGR, r. 40(2).

the service provider's forecasting method as well as the inputs and assumptions it used to form its opex forecast.

If a service provider's total forecast opex is sufficiently different to our estimate, we will examine the reasons for the difference. If there is no satisfactory explanation for this difference, we may form the view that the service provider's forecast does not comply with the opex criteria. If we are not satisfied that the proposed opex complies with the opex criteria we use our alternative opex estimate as a substitute. Conversely, if the service provider's forecast is consistent with our estimate, this may suggest that the service provider's forecast is consistent with the opex criteria and we may accept the forecast.

Whether or not we accept a service provider's forecast, we will provide the reasons for our decision.

### 7.3.1 Building an alternative estimate of total forecast opex

Our approach to forming an alternative estimate of opex involves five key steps:

1. We typically use the service provider's actual opex in a single year as the starting point for our assessment. While categories of opex can vary from year to year, total opex is relatively recurrent.[4]
2. We assess whether opex in that base year complies with the opex criteria. If necessary, we make an adjustment to the base year expenditure to ensure that it complies with the opex criteria.
3. As opex tends to change over time due to price changes, output and productivity, we trend the adjusted base year expenditure forward over the access arrangement period to take account of these changes. We refer to this as the rate of change.
4. We then adjust the base year expenditure to account for any other forecast cost changes over the forthcoming access arrangement period that would meet the opex criteria. This may be due to new regulatory obligations and efficient capex/opex trade-offs. We call these step changes.
5. Finally we add any additional opex components which have not been forecast using this approach. If we removed a category of opex from the selected base year, we will need to consider what additional opex is needed for this category of opex in forecasting total opex.

We have used this general approach in our past decisions. It is a well-regarded top-down forecasting model for regulatory purposes that has been employed by a number of Australian regulators over the last fifteen years. We have sometimes

4 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013 and AER, *Explanatory Statement Expenditure Forecast Guideline,* November 2013.

referred to it as the base-step-trend method in our past regulatory decisions.[5] More detail about each of the steps is contained in our draft decision.[6]

### 7.3.2 Interrelationships

We note there are interrelationships between our opex forecast and other elements of ActewAGL's proposal. In assessing ActewAGL's total forecast opex we took into account these components, including:

- the operation of the efficiency carryover mechanism in the current period, which provided an incentive to reduce opex throughout the period (Attachment 9)
- the impact of forecast demand and connection numbers on output growth in the rate of change (Attachment 13)
- the interrelationship between capex and opex in considering proposed step changes to opex (Attachment 6)
- the impact of ActewAGL's capitalisation policy on capex and opex (Attachment 6)
- 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 (Attachment 3)
- the concerns of stakeholders identified in the course of ActewAGL's consultation with consumers and in submissions to the AER.

## 7.4 Reasons for final decision

### 7.4.1 Forecasting method

ActewAGL's revised opex forecast retains the base-step-trend approach used in its initial proposal, and that is consistent with our proposed method. We continue to be satisfied that ActewAGL's forecasting method is not the key driver of the difference between our and ActewAGL's forecast opex. Rather, different inputs and assumptions used in the forecasting method explain the difference.

### 7.4.2 Base year opex

Determining efficient, recurrent expenditure in the base year is at the core of our single year revealed cost approach. We consider which year should be used as the base year and whether it is efficient. We also decide whether any costs incurred in the base year should be removed to establish an efficient base level of opex to be used to forecast total opex for the next access arrangement period.

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5 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013 and AER, *Explanatory Statement Expenditure Forecast Guideline,* November 2013.

6 AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 7 - Operating Expenditure*, November 2015, pp. 11,12.

#### 7.4.2.1 Which year should be used as the base year?

ActewAGL's revised proposal maintains 2014–15 as the proposed base year, which we accept. ActewAGL's revised proposal contains an updated actual opex figure for 2014-15. This is $28.6 million ($2015–16), excluding debt raising costs, and is $1.0 million ($2015–16) higher than the estimate contained in its initial proposal.

We consider 2014–15 a reasonable base year for forecasting opex as:

- Most opex is recurrent in nature and actual costs incurred in 2014–15 are likely to be a good indicator of efficient costs in the 2016–21 period, particularly given the operation of an efficiency carryover mechanism in the current period.
- 2014–15 is the latest year for which actual audited data is available. To the extent that cost drivers do not change over time, 2014–15 is likely to best reflect expenditure in the forecast period.
- ActewAGL’s opex has been relatively stable over the 2010–15 access arrangement period.
- ActewAGL's opex was subject to an efficiency carryover mechanism in the 2010-15 period, which reduces the incentive for ActewAGL to increase its opex in its proposed base year.

#### 7.4.2.2 Is base opex efficient?

We have not been presented with evidence to suggest that ActewAGL’s revealed costs in its proposed base year are inefficient.

In our assessment of ActewAGL’s efficient opex, we rely primarily on our analysis of ActewAGL’s historical trends, the information submitted by ActewAGL as well as relevant information submitted by other gas network service providers in recent regulatory proposals.

Relevant to our assessment of base year opex is that ActewAGL was subject to an opex efficiency incentive mechanism in the 2010–15 period. Typically, where a service provider is subject to an incentive mechanism, we are satisfied that there is a continuous incentive for a service provider to make efficiency gains and it does not have an incentive to increase its opex in the proposed base year.

We did not conduct our own economic benchmarking or category analysis to assess the efficiency of ActewAGL’s revealed base year. This is because we do not have standardised data across gas network service providers (where we do for electricity network service providers).

#### 7.4.2.3 Base year adjustments

The adjusted base year opex in ActewAGL's revised proposal is $21.4 million ($2015-16). This is $4.5 million higher than the $16.9 million ($2015–16) adjusted base opex in its initial proposal. It is also $2.8 million higher than the adjusted base opex of $18.6 million ($2015–16) we determined in our draft decision.[7]

ActewAGL accepted our draft decision in relation to category specific forecasts.[8] Our draft decision did not agree with ActewAGL's initial proposal that ancillary services, water bath heater operations and insurance costs should be separately forecast. ActewAGL's revised proposal incorporates these costs into its base opex. ActewAGL has also accepted our draft decision that the base year be assessed exclusive of any movements in provisions, consistent with our general assessment methodology.[9][10]

In a reversal of its initial proposal, ActewAGL's revised proposal does not remove access arrangement reset costs ($2.3 million ($2015–16)) and JAM one-off costs and changes in cost allocation[11] ($0.2 million ($2015–16)) from its base year opex. ActewAGL's revised proposal also proposes that costs associated with the Hoskinstown operating and maintenance contract be included in base opex rather than treated as a step change. Our assessment of these issues is set out below.

### *Access arrangement review costs*

ActewAGL's initial proposal removed $2.3 million ($2015–16) from its base year for costs associated with the preparation of its 2016–21 access arrangement. This was proposed by ActewAGL on the basis that these costs were non-recurrent. To account for the costs ActewAGL expected to incur to prepare its 2021–26 access arrangement, it included a separate $3.2 million ($2015–16) step change.

Our draft decision included access arrangement costs in base opex as we considered that costs to prepare an access arrangement are recurrent, but lumpy in nature.[12] However, rather than including the full base year cost associated with this cost category we adjusted the amount to 20 per cent of the base year costs. We did this to allow ActewAGL to recover the costs associated with this cost category evenly over the next access arrangement period.[13]

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7 AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 7 - Operating Expenditure*, November 2015, p. 14.

8 ActewAGL, ***Response to the AER's draft decision, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access*** *Arrangement*, January 2016, p. 89.

9 ActewAGL, ***Response to the AER's draft decision, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access*** *Arrangement*, January 2016, p. 71.

10 In our final decision we maintain this adjustment, but reflect the latest changes in provisions reported in ActewAGL's revised Regulatory Information Notice.

11 For a description of these costs see pp. 21–22 of ActewAGL's 2021-16 Access Arrangement Information: Attachment 5 Operating Expenditure (June 2015).

12 AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 7 - Operating Expenditure*, November 2015, p16. We note that typically electricity and gas network service providers include costs associated with the preparation of their access arrangements in their base year costs.

13 We also did not accept the step change associated with the 2021–26 access arrangement review. Our draft decision notes that costs associated with the preparation and submission of an access arrangement do not result from a material change in circumstances and our base opex provides for access arrangement review costs.

ActewAGL considered our approach of applying a portion of the reset costs in the 2014-15 base year understated its efficient access arrangement costs. This is because costs for this category occur in two other years of the period (albeit at lower levels) and we accounted only for those costs that were incurred in the base year.[14] CCP8 also submitted that our draft decision was likely to understate the true cost of the activity over a five-year period.[15] We acknowledge that our inclusion of only a portion of base year access arrangement costs is not consistent with our revealed cost approach.

ActewAGL also considered that our approach of modifying the base opex would impose excessive penalties on it as we did not make corresponding adjustments in calculating carryover amounts associated with its 2010-15 efficiency carryover mechanism. This view was supported by a report from its consultant HoustonKemp.[16] We have considered this report and acknowledge that our opex and efficiency carryover mechanism models did not treat the reset revision costs consistently which resulted in lower carryover amounts being applied to the revenue building blocks for 2016–21 period.

We have reconsidered this cost category and note that there are two broad approaches within the single year revealed forecasting approach that could be taken with respect to these costs. Firstly, an adjustment could be made to take into account the 'lumpy' nature of the costs. Any adjustments made to the opex model would need to be accompanied with corresponding adjustments in the calculation of efficiency carryover amounts. Secondly, revealed opex in the 2014–15 base year could be applied without any adjustment in either the opex or efficiency carryover mechanism models. Either approach results in a similar net revenue outcome.

ActewAGL has proposed the second approach in its revised proposal. This approach is based on ActewAGL's acceptance of our draft decision[17] with respect to its efficiency carryover calculations from the 2010–15 period, which did not make any adjustments to actual opex in 2014–15 for access arrangement costs.[18]

Our final decision is to accept ActewAGL's revised proposal approach, that is, to include the costs associated with the access arrangement incurred in 2014-15 in ActewAGL's base year opex. This approach is consistent with our single year revealed cost approach and is consistent with the treatment of this cost category for other service providers. We recognise that some cost categories are higher in some years and lower in others but a key consideration is not whether an individual cost category

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14 ActewAGL, *Response to the AER's draft decision, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, January 2016, pp. 72–74.

15 Consumer Challenge Panel, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding the AER Draft Decision and ActewAGL Distribution's Revised Access Arrangement 2016-2021 Proposal*, 23 March 2016, p. 2.

16 HoustonKemp, *Efficiency carryover mechanism - a report for DLA Piper for ActewAGL,* 4 January 2016.

17 ActewAGL, *Response to the AER's draft decision, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, January 2016, pp. 92–93.

18 We also note that ActewAGL has proposed to retain a step change for costs associated with the 2021–26 access arrangement review. Our assessment of this step change is considered in section 7.4.4.

is lumpy but whether the total opex is lumpy.[19] As noted in section 7.4.2.1, we consider ActewAGL’s opex has been relatively stable over the 2010–15 period.

We also note that this approach also has the benefit of being more transparent and easy to implement as fewer adjustments to the opex and efficiency carryover mechanism models are required. Incorporation of these costs into base year also clarifies that these costs are included in the operation of the efficiency carryover mechanism for the 2016–21 period.

### *JAM one-off costs and changes in cost allocation*

Like access arrangement reset costs, ActewAGL's revised proposal now retains cost allocation changes and JAM one-off costs totalling $0.2 million ($2015–16) in its base year opex rather than removing them.[20] These items relate to several non-recurrent costs included in the asset services and management services fees.

Our final decision adopts ActewAGL's revised approach with respect to these costs. We note that when determining adjustments that apply in the base year, we take into account not only whether they are non-recurrent but also whether they are material.[21] We have decided to maintain these costs in the base year as we do not consider them material. We also note that this treatment results in a similar net revenue impact had we removed the amount from our opex and efficiency carryover mechanism models.

### *Hoskinstown operating and maintenance contract costs*

ActewAGL's revised proposal contains an increase of $0.04 million ($2015-16) to the base year for costs associated with the Hoskinstown operating and maintenance contract renegotiation. This item involves costs associated with renegotiating a new contract and ongoing costs in each year of the access arrangement to deliver operating and maintenance services.[22]

We note that this item was proposed by ActewAGL as a step change in its initial proposal but we did not accept it in our draft decision. We considered the contract negotiation costs were a business as usual cost and ongoing operating and maintenance costs were provided for through our rate of change factor.[23]

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19 AER*, Explanatory Statement Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013, p. 29.

20 ActewAGL's initial proposal removed from the base year an amount of $0.2 million ($2015–16) for cost allocation changes in the Distribution Asset Management Services (DAMS) agreement between ActewAGL and Jemena Asset Management (JAM) and one-off JAM costs. Our draft decision accepted this adjustment.

21 AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 7 - Operating expenditure, November 2015*, section 7.3.1.

22 ActewAGL, *Appendix 7.02 Hoskinstown operations and maintenance contract costs base year adjustment, Revised 2016-21 access arrangement proposal, Response to the AER’s draft decision (Public)*, January 2016.

23 AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 7 - Operating expenditure, November 2015*, p. 30.

While ActewAGL acknowledges our draft decision and has not included the item as a step change in its revised proposal, it has re-proposed this item as an increase to its base year opex.

We have considered ActewAGL's proposal and do not agree that the Hoskinstown operating and maintenance contract costs should be included as a one-off adjustment to ActewAGL's base opex.[24] We consider that the contract negotiation costs are business as usual type costs and variations in the composition of any expenditure category, year to year, is expected. Therefore these contract renegotiation costs are provided for in the revealed base year costs. With regard to ongoing operating and maintenance costs, we maintain that any change in these costs due to higher forecast throughput are provided for in our rate of change calculations, specifically the output change component.

#### 7.4.2.4 Overall adjusted base opex

We are satisfied that ActewAGL's revised 2014–15 base year opex of $21.4 million ($2015-16) is a reasonable estimate for the purpose of forecasting opex for the 2016-21 period. Our estimate is derived using the same methodology as ActewAGL, except we do not incorporate the Hoskinstown operating and maintenance contract costs.

We have not identified other non-recurrent opex in the base year that we consider should be excluded or additional cost categories that we consider should be specifically forecast.

### 7.4.3 Rate of change

Once we determine the efficient base level of opex, we apply a forecast annual rate of change to account for efficient changes in opex over time. In our *Expenditure Forecast Assessment Guideline* we developed a methodology for adjusting base year opex known as the rate of change.[25] The rate of change is the 'trend' component of the Base–Step–Trend forecasting method. It is forecast as:

$$\Delta Opex = \Delta input\ price + \Delta output - \Delta productivity$$

where $\Delta$ denotes the proportional change in a variable.[26]

The rate of change captures the year on year change in efficient expenditure. Specifically, it accounts for forecast changes in outputs, prices and productivity. These

24 We note that ActewAGL did not make the corresponding adjustment for this proposed cost in its ECM carryover calculations for its revised proposal. However, as we do not accept this adjustment in our final decision, no adjustment to our ECM carryover calculations is required.

25 AER, *Expenditure forecast assessment guidelines - Explanatory statement*, November 2013, p. 61.

26 Rather than the simplified formula shown above, the formula used by the AER to derive total rate of change takes into account the cumulative nature of the rate of change factors, $Rate\ of\ change = (1 + \Delta input\ price) \times (1 + \Delta output) \times (1 - \Delta productivity) - 1$.

three opex drivers should explain all changes in efficient opex. The output and productivity change variables capture the forecast change in the inputs required. The real price change variable captures the forecast change in the prices of those inputs.

#### 7.4.3.1 Overall rate of change

Our final rate of change calculations are the same as those used by ActewAGL in its revised opex model, but we have updated our calculations to include the latest forecasts for labour (affecting the input price factor), and the latest forecasts for demand and customer connections (affecting the output change factor). As a result, our overall rate of change differs slightly from that contained in ActewAGL's revised proposal.

Table 7.3 compares our final position on each rate of change component and the overall rate of change with ActewAGL's revised proposal.

### Table 7.3 ActewAGL and AER overall rate of change (per cent)

| | 2015–16 | 2016–17 | 2017–18 | 2018–19 | 2019–20 | 2020–21 |
|---|---|---|---|---|---|---|
| **AER decision** | | | | | | |
| Input price change | 0.55 | 0.21 | 0.47 | 0.64 | 0.73 | 0.89 |
| Output change | 1.08 | 1.12 | 1.13 | 1.31 | 1.37 | 1.23 |
| Productivity change | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 |
| Overall rate of change | 1.08 | 0.78 | 1.05 | 1.41 | 1.55 | 1.57 |
| **ActewAGL revised proposal** | | | | | | |
| Input price change | 0.28 | 0.41 | 0.60 | 0.75 | 0.75 | 0.91 |
| Output change[27] | 1.21 | 0.96 | 1.14 | 1.32 | 1.33 | 1.22 |
| Productivity change | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 | 0.55 |
| Overall rate of change | 0.95 | 0.83 | 1.19 | 1.52 | 1.53 | 1.58 |
| Difference | 0.14 | - 0.04 | - 0.14 | - 0.12 | 0.03 | - 0.02 |

Source: ActewAGL Distribution - Revised 2016-21 access arrangement proposal - Appendix 7.01 Revised proposal opex model - January 2016; AER analysis. Numbers may not add due to rounding.

The following sections outline our assessment for each rate of change component.

#### 7.4.3.2 Input price change

27 The opex model ActewAGL submitted in January 2016 contained incorrect data for customer connections and demand. The data in this table corrects for these, consistent with Information Request 44. (ActewAGL, *Response to AER Information Request 044* [email to AER], 21 January 2016.)

Under the rate of change approach, opex is escalated by the real change in input prices. The change in input prices accounts for key inputs that do not move in line with CPI and form a material proportion of a service provider's costs.

ActewAGL accepted our draft decision in its revised proposal. We have not altered our method for forecasting input price change in our final decision. However, as anticipated in our draft decision, we use the latest labour price growth forecasts, where available, in our final decision.[28] This results in a slight difference in input price change from our draft decision and therefore ActewAGL's revised proposal. Table 7.4 contains our final decision on input price change.

### Table 7.4 AER real input price change (per cent)

| | 2015–16 | 2016–17 | 2017–18 | 2018–19 | 2019–20 | 2020–21 |
|---|---|---|---|---|---|---|
| AER | 0.55 | 0.21 | 0.47 | 0.64 | 0.73 | 0.89 |

Source: AER analysis.

#### 7.4.3.3 Output change

Output change captures the change in expenditure due to changes in the level of outputs delivered. Under our rate of change approach, a proportional change in output results in the same proportional change in expenditure. Any subsequent adjustment for economies of scale is considered as a part of productivity.

Our draft decision did not consider ActewAGL's forecast output change the best estimate possible in the circumstances as it was based solely on new customer connections.[29] We applied an output weight ratio of 55:45 for demand and customer connections, on the basis that changes in gas demand also impacted total opex. [30]

ActewAGL did not agree with the AER's draft decision. Its view was informed by ACIL Allen’s productivity study into its gas network businesses. It considered that small reductions in demand have little impact on network opex and that demand ignores the more important cost driver of peak demand.[31]

While ActewAGL maintained its initial bottom-up approach for forecasting output change (based solely on new customer connections) provided the best possible

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28 February 2016 DAE forecasts for ACT utilities sector real wages have been applied in this final decision, however, for other components of the real input price change the same labour price growth forecasts we applied in our draft decision have been used.

29 AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 7 - Operating expenditure,* November 2015, p. 20.

30 These output weights were also used by the AER to determine the output change factor for JGN in its recent access arrangement decision and was based on Economic Insights modelling.

31 ActewAGL, *2016-21 access arrangement response to draft decision*, January 2016, p. 77.

forecast, its revised proposal applied an alternative output weight calculation based on a top-down approach.[32]

ActewAGL stated that, if the AER maintains a preference for the use of a top-down forecast, the next best alternative is to apply an average of the output weights from the ACIL Allen and Economic Insights modelling. It considered there was no statistical test to assess which model is statistically more robust.[33] As a result, ActewAGL's revised opex model derives its output weights by averaging the 100 per cent weight for customer connections and zero per cent for demand (used in the ACIL Allen report) with the output weights applied in the AER's draft decision (based on the Economic Insights report). This results in an output weight ratio of 72.5: 27.5 for customer connections and demand respectively.

We note that ActewAGL's revised opex model also applies an averaging approach in relation to the productivity factor and we agree with ActewAGL that consistency in treatment between output growth and productivity is important given the interlinkages between these rate of change components. We have considered the issues raised by ActewAGL and undertaken our own analysis of the ACIL Allen and Economic Insights studies. As a result of this analysis, we consider that the output weights proposed by ActewAGL, when used in conjunction with our updated demand and customer connections forecasts, result in an annual output change that has been arrived at on a reasonable basis and represents the best estimate in the circumstances.[34]

Table 7.5 contains our final decision on output change.

### Table 7.5 AER output change (per cent)

| | 2015–16 | 2016–17 | 2017–18 | 2018–19 | 2019–20 | 2020–21 |
|---|---|---|---|---|---|---|
| AER | 1.08 | 1.12 | 1.13 | 1.31 | 1.37 | 1.23 |

Source: AER analysis.

### 7.4.3.4 Productivity change

ActewAGL applied a zero per cent productivity change in its initial proposal. It chose not to apply the average annual forecast of 0.5 per cent derived in ACIL Allen's April 2015 productivity study of ActewAGL's gas network business as it did not consider the findings of the study to be suitably robust.[35] ActewAGL also argued the efficiency carryover mechanism ensures efficient costs are achieved.

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32 ActewAGL, *Response to the AER's draft decision, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, January 2016, pp. 76–77.

33 ActewAGL, *Response to the AER's draft decision, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, January 2016, p. 77.

34 Attachment 13 contains our assessment of ActewAGL's revised gas demand and customer connections forecasts.

35 ActewAGL considered there were limitations with benchmarking (including model selection, model parameters and data).

Our draft decision applied ACIL Allen Consulting's forecast productivity of 0.5 per cent per annum to derive an overall opex rate of change for ActewAGL. We noted that the application of the efficiency carryover mechanism did not obviate the requirement on us under the NGR to set a total opex forecast consistent with the opex criteria and that inclusion of forecast productivity change is necessary for us to be satisfied that total forecast opex complies with the opex criteria. We also considered ActewAGL should be able to achieve productivity growth in the period. Our reasons are outlined in our draft decision.[36]

While ActewAGL maintained its initial proposal provided the most appropriate forecast, its revised opex model applies our top-down approach with an annual productivity factor of 0.55 per cent. ActewAGL calculates the productivity factor in its revised proposal by taking an average of the 0.5 per cent result from the ACIL Allen productivity study and the 0.59 per cent result from the Economic Insights study commissioned by JGN as part of its 2015-20 access arrangement.[37] ActewAGL states it has applied this approach because, if a productivity growth factor is to be included in opex forecasts, it considers it essential to consider productivity together with the setting of output growth rates when both are set using econometric model estimates.[38]

We have reviewed ActewAGL's revised approach which averages the results of the ACIL Allen and Economic Insights models to derive an annual productivity factor. We note ActewAGL uses a similar averaging approach to determine its revised output change and agree with ActewAGL that consistency in treatment between the output and productivity factors is important, given the interlinkages between these rate of change components. Based on our analysis of the ACIL Allen and Economic Insight studies, we consider ActewAGL's estimate of annual productivity is the best estimate available to the AER in the circumstances. Therefore, we have concluded that it is reasonable to accept ActewAGL's proposal to apply an annual 0.55 per cent productivity factor for the forecast period.

### 7.4.4 Step changes

ActewAGL's revised proposal contained nine step changes totalling $6.3 million ($2015-16). We accepted three of the proposed step changes in our draft decision: National Energy Customer Framework (NECF) compliance, National Business to Business harmonisation and changes in capitalisation policy.[39] ActewAGL's revised

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36 AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 7 - Operating expenditure,* November 2015, pp. 21–23.

37 ACIL Allen Consulting, *Final report to Jemena Asset Management on behalf of ActewAGL distribution gas network 'Productivity Study - ActewAGL Distribution Gas Network*', 29 April 2015 p. xii; and Jemena Gas Networks, *2015-20 Access arrangement, Response to the AER's draft decision and revised proposal, Appendix 5.2* - Economic Insights Updated productivity assessment for JGN, 27 February 2015, p. iii.

38 ActewAGL, ***Response to the AER's draft decision****, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, January 2016, p. 78.

39 In its revised proposal ActewAGL accepted AER's draft decision not to accept its revised metering technical code and RIN reporting step changes.

proposal contains two new step changes and includes four re-proposed step changes that we either rejected or partly rejected in our draft decision.[40] We assess these new and re-proposed step changes to determine whether these should be included in our total opex forecast.

For our final decision we accepted the following step changes proposed by ActewAGL:

- National Energy Customer Framework compliance
- National Business to Business harmonisation
- Change in capitalisation policy
- Tariff variation notice (gas quantities audit).

Table 7.6 shows our decision on each step change and our reasons are set out below.

### Table 7.6 AER decision on step changes ($million, 2015–16)

| Step change | ActewAGL revised proposal | AER final decision |
|---|---|---|
| National Energy Customer Framework compliance | 0.77 | 0.77 |
| National Business to Business harmonisation | 1.05 | 1.05 |
| IT asset utilisation fee | 4.17 | 0 * |
| Network risk and security management | 0.54 | 0 |
| Periodic inspections | 0.30 | 0 |
| New capex-driven opex | 0 ^ | 0 |
| 2021 access arrangement revision | 4.03 | 0 |
| Change in capitalisation policy | -5.51 | -4.79 |
| New tariff strategy implementation | 0.77 | 0 |
| Tariff variation notice gas quantities | 0.14 | 0.14 |
| Total | 6.26 | -2.83 |

Note: *Our final decision includes the ITAUF amount as a category specific forecast, rather than a step change.
^ActewAGL's revised proposal did not include the capex driven step change on the basis that its proposed output growth forecast was accepted.

Source: ActewAGL Distribution - Revised 2016-21 access arrangement proposal - Appendix 7.01 Revised proposal opex model January 2016; AER analysis. Numbers may not add due to rounding.

### *National Energy Customer Framework compliance*

[40] In our draft decision we accepted the Business to Business harmonisation and NECF requirement components of the ITAUF step change but rejected the component associated with the replacement of the GASS+ IT system.

In our draft decision we agreed to ActewAGL's proposed step change of $0.8 million ($2015–16) over the access arrangement period for increased operational costs to comply with NECF customer support and billing and NECF connection services requirements in our total opex forecast. This step change is driven by an increase in ActewAGL's regulatory obligations and does not double count costs captured in the base year expenditure. ActewAGL accepted our draft decision in its revised proposal.

Our final decision is to include this step change in our total opex forecast for ActewAGL.

### *National Business to Business harmonisation*

In our draft decision we included ActewAGL's proposed step change of $1.1 million ($2015–16) to meet obligations for business to business transactions with energy retailers in our total opex forecast. This step change is driven by a change in ActewAGL's regulatory obligations and the costs are not captured in the base year expenditure. ActewAGL accepted our draft decision in its revised proposal.

Our final decision is to include this step change in our total opex forecast for ActewAGL.

### *Change in capitalisation policy*

In its initial proposal, ActewAGL proposed a negative step change of $6.6 million ($2015–16) to account for a change in the way corporate overhead costs are allocated under its Cost Allocation Methodology (CAM).

The proposed step change results from the alignment of ActewAGL's gas network CAM with that of its ActewAGL's electricity network (from 1 July 2015). The change involves annual allocations of total corporate overheads to capex rather than opex.

In our draft decision, we revised the forecast corporate overhead costs allocated to capex amount to $4.6 million ($2015–16) for the 2016–21period as a result of our capex assessment.[41] ActewAGL accepted the draft decision but in its revised proposal amended the negative step change to amount of $5.51 million reflecting its revised capex program.[42]

We note that as a result of our further assessment of ActewAGL's capex for this final decision (Attachment 6), forecast corporate overhead costs allocated to capex have been revised to $4.8 million for the 2016–21 period. Consequently, for this final decision we have included a negative opex step change of $4.8 million ($2015–16).

### *IT asset utilisation fee (re-proposed)*

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[41] AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 6 - Capital Expenditure*, November 2015, pp. 6-38, 6-39.

[42] ActewAGL, *Response to the AER's draft decision, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, January 2016, p. 81.

In its initial proposal ActewAGL included a step change of $4.17 million ($2015–16) for an IT asset utilisation fee (ITAUF).[43] The ITAUF relates to the development of a new IT system by JGN that will be used by ActewAGL. Specifically, the project involves the replacement of the existing GASS IT system[44] with a new OneSAP system. The replacement project has three main components: a business as usual component; a business to business harmonisation component and a NECF component. The ITAUF costs are not ongoing and will only be incurred in the 2016–21 period.

Our draft decision only accepted ITAUF costs associated with the business to business harmonisation and NECF components of the project as step changes as they were considered to be associated with a change in regulatory obligations. However, we did not accept the component to replace the GASS+ IT system as we considered that this cost related to the delivery of business as usual services.[45]

In its revised proposal ActewAGL has re-proposed that the full value of the ITAUF step change is required to allow it to recover its efficient costs for the GASS IT replacement system. It states that it is problematic to apply the AER's usual opex forecasting approach to the ITAUF because this particular IT investment would normally be considered capex. It states that the project is a capex IT investment with the non-recurrent capex costs being shared between JGN and ActewAGL, with ActewAGL's share being paid by it to JAM under the DAMs agreement.[46] ActewAGL states that the combination of its DAMs agreement with JAM and accounting standards (AASB 116) results in it treating this investment as opex.

Having further considered the issues raised by ActewAGL we now consider that the ITAUF is more appropriately treated as a specific category forecast. This is because a specific category forecast recognises the non-recurrent nature of the ITAUF costs and that these costs should not form part of the base opex in the next period. In addition, we note that treatment as a specific category forecast means that ITAUF costs are excluded from the operation of the opex efficiency carryover mechanism.

We reviewed ActewAGL's forecast for this step change together with its DAMs agreement with JAM. We agree that the annual ITAUF fees have been calculated to recover the non-recurrent capital costs associated with ActewAGL's share of the GASS+ replacement project. Further, we note that the capital expenditure forecasts underlying the ITAUF are consistent with the total capital expenditure forecasts that we approved for this project in JGN's 2015-20 access arrangement.[47]

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43 ActewAGL, *2016-21 access arrangement response to draft decision* January 2016, p. 82.

44 ActewAGL also advised in its revised proposal that the GASS+ system had been fully depreciated by 2014-15 and therefore no such fees were included in the base year.

45 AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 7 - Operating Expenditure, November 2015*, p. 7-29.

46 ActewAGL, *2016-21 access arrangement response to draft decision* January 2016, p. 82.

47 ActewAGL's allocation of costs reflects 10.14 per cent of the total GASS+ replacement project cost and is based on customer number relativities across JGN and ActewAGL Distribution's gas network.

We also reviewed JGN's business case for this project to ensure that JGN's customers were not paying for the same IT project costs twice and we are satisfied that this is not the case.[48] We found that JGN had only included its portion of the capital expenditure associated with the GASS+ replacement project in its 2015-20 access arrangement.

We consider that treatment of ITAUF costs as a category specific forecast is appropriate given the non-recurrent nature of these costs. In this regard we note that fees have been determined by depreciating ActewAGL's share of the project costs over a five year period. As such, the ITAUF should not continue beyond the 2016-21 period. We also consider that the fees reasonably reflect ActewAGL's share of the GASS+ replacement system costs.

Our final decision is not to accept ActewAGL's ITAUF costs as a step change. Instead, we have included ActewAGL's proposed expenditure on this item as a category specific forecast in our alternative opex forecast (section 7.4.5).

### *Periodic inspections step changes (re-proposed)*

Consistent with our draft decision, we have not included the re-proposed step changes related to periodic inspections of exposed main and water bath heater assets or network risk and security management in our opex forecast.

ActewAGL's initial proposal included a proposed step change of $0.5 million ($2015–16) to undertake periodic risk safety management studies (risk assessments) of its high pressure networks under Australian Standard (AS) 2885.[49] ActewAGL stated that the AS 2885 suite of Australian Standards require pipeline owners to undertake periodic safety management studies of their assets to ensure the continuing safe and reliable operation of those assets. It also stated that its proposed step change reflected the periodic nature of the requirement and that no safety management studies were planned or required during the base year 2014–15.

ActewAGL's initial proposal also included a proposed step change to undertake periodic inspections of exposed main and water bath heater assets at a cost of $0.3 million ($2015–16). It stated that its exposed mains require regular and comprehensive inspections and that its water bath heaters need to be maintained to meet the manufacturer's and regulatory requirements. ActewAGL further stated that the periodic inspections accounted for in the proposed step change were not undertaken in the base year and are therefore not included in base opex.

In our draft decision we did not accept either of these step changes as we noted that ActewAGL is already required to ensure its pipelines are prudently managed, and undertakes periodic assessments as part of this obligation. We also noted that the

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[48] Consumer Challenge Panel, *Submission to the AER, CCP8 - Advice to AER from Consumer Challenge Panel sub-panel 8 regarding the ActewAGL Distribution (AAD) Access Arrangement (AA) 2016-2021 Proposal*, 26 August 2015, p. 8.

[49] The step change also included some minor costs associated with security management.

amount forecast for these items was not material and that some variation in the composition of expenditure from year to year is expected under our forecasting approach. This means that expenditure for some categories will be higher than usual in a given year, while other categories will be lower than usual. On this basis we did not accept the step changes as we considered they were captured in our assessment of base opex.[50]

ActewAGL has responded to our draft decision by combining its network risk and security management step change ($0.54m, $2015–16) and its periodic inspections of exposed mains and water bath heater assets step change ($0.30m, $2015–16) under the heading of periodic step changes and re-proposing them. It stated that activities covered by these step changes are periodic in nature (they are not activities undertaken every year, but at intervals of up to five years between activities) and not recurrent. It also stated that the activities nominated were not undertaken in the 2014–15 base year.[51]

In re-proposing these step changes, ActewAGL stated that it did not consider the AER's draft decision that the amount forecast for these items was not material was an acceptable reason to reject a step change. Although acknowledging that there is some scope for variation in activity from year to year for opex, it considered the combined value of these step changes of $0.8 million was material. It maintained its view that these step changes should be approved and included in its opex forecast for the 2016-21 period.

Consistent with our draft decision we do not accept these step changes. We consider these costs are recurrent in that they will occur in each access arrangement period and also note no evidence has been provided to show that these programs are a response to a new or changed obligation or a material change in circumstances. We consider that they are not step changes but programs developed in response to existing obligations. Further we consider that our alternative opex forecast (which has been based on ActewAGL's revealed base year costs) overall provides an efficient level of opex to allow ActewAGL to manage these activities.

### *New capex-driven opex*

In its initial proposal, ActewAGL included a $0.6 million ($2015–16) step change in opex to account for additional work and resource requirements resulting from upgrades in capital equipment at the following sites:

- Fyshwick Trunk Receiving Station
- Hoskinstown Custody Transfer Station

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[50] AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 7 - Operating Expenditure*, November 2015, p. 7-31.

[51] ActewAGL, ***Response to the AER's draft decision**, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, January 2016, pp. 82, 83.

- Philip Primary Regulating Station
- Watson Pressure Limiting Station
- Molonglo primary main.[52]

ActewAGL's initial proposal stated that these assets are required to be maintained to the manufacturers' and regulatory requirements and that opex associated with these assets had not been included in its incremental cost per customer output growth forecast.

In our draft decision we considered that opex associated with these capital upgrades and projects was provided for as part of our forecasting approach through the application of the rate of change factor to the base opex. This is because the rate of change includes a component for changes in output of the network (based on forecast changes in consumption and customer connections). We therefore did not accept the proposed capex-driven opex should be treated as a step change.[53]

In its revised proposal ActewAGL considered that there was persuasive evidence for adopting its original approach to forecasting output growth (capex-driven step changes plus incremental costs per customer for the Secondary and Medium pressure networks). However, ActewAGL indicated that if the AER was to apply a forecast of output growth using the econometric models, the output growth forecast should be sufficient to cover its costs. ActewAGL's revised opex forecast therefore did not include its proposed capex-driven step change in its opex modelling on the basis that its proposed output growth forecast was accepted.[54]

The AER's assessment of the output growth component of the rate of change is set out in section 7.4.3 of this attachment. In summary we have accepted the output growth weightings proposed by ActewAGL in its revised proposal but have applied our updated demand and customer connections forecasts in modelling output growth for the next period.  We have not included ActewAGL's proposed new capex driven step change in our total opex forecast as we consider that an efficient level of opex for these assets is provided through output component of the rate of change calculations.

### *2021 access arrangement revision project (re-proposed)*

[52] ActewAGL also proposed a negative step change due to the closure of the Jerrabomberra Packaged Off-take Station.

[53] AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 7 - Operating Expenditure*, November 2015, p. 7-31.

[54] ActewAGL, *Response to the AER's draft decision, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, January 2016, pp. 83, 84.

We do not accept the $4.0 million ($2015–16) step change re-proposed by ActewAGL for costs associated with the preparation and submission of its 2021–26 access arrangement.[55]

As noted in section 7.4.2, ActewAGL's initial proposal removed from the base year $2.3 million ($2015–16) for costs associated with the preparation and submission of its 2016–21 access arrangement on the basis this cost was non-recurrent. As this cost category was removed from the base year, ActewAGL proposed a step change totalling $3.2 million ($2015–16) in order to account for the opex incurred to prepare the next 2021–26 access arrangement.[56]

Our draft decision[57] considered access arrangement costs to be recurrent, but lumpy, expenditure. As such, we did not remove the 2016-21 access arrangement revision costs totally from the base year, but included a proportion (20 per cent) of the base year costs in order to smooth the profile of this expenditure over the next period. As a proportion of the access arrangement revision costs were reflected in base year costs, we did not accept the step change for the 2021–26 access arrangement. We also considered there was no change in regulatory obligations or material change in circumstances associated with the 2021–26 access arrangement compared to the 2016–21 access arrangement that required a step change.

In its revised proposal ActewAGL has retained the full value of the access arrangement revision costs in its base year opex. However, it has also maintained that a step change is required to compensate it for its efficient opex associated with its 2021–26 access arrangement. It states that this is because the inclusion of access arrangement costs within the adjusted base opex "suffices only to ensure that that loss is shared between ActewAGL Distribution and consumers on a 30:70 basis".[58]

ActewAGL also refer to a report by its consultant, HoustonKemp, that examined the interrelationship between the opex forecasting approach and calculation of ECM carryover amounts for ActewAGL in the AER's draft decision. While the primary conclusion of the report was that the AER over penalised ActewAGL by treating costs inconsistently between the base year and the efficiency carryover mechanism (refer to section 7.4.2.3), it also supported ActewAGL's view that a separate step change for reset revision costs was required (in addition to the inclusion of these costs in the base year).[59] The report, however, does not provide any further reasoning or assessment to support its assertion that a step change is required.

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55 This amount is greater than the amount of $3.2 million in ActewAGL's initial proposal. ActewAGL indicated that its increased forecast for this item was based on updated actual and budgeted costs for the 2016-21 access arrangement revision project.

56 ActewAGL, *2016 – 21 access arrangement information, Appendix 5.04 Step changes report*, June 2015, pp. 39-42.

57 AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 7 - Operating Expenditure*, November 2015, p. 16.

58 ActewAGL Distribution, ***Response to the AER's draft decision 2016-21** ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, 6 January 2016, p. 85.

59 HoustonKemp, Efficiency carryover mechanism - a report for DLA Piper for ActewAGL - 4 January 2016, p. 11, 12.

We note that ActewAGL's revealed base year costs include its access arrangement revision costs and these costs have been used by us to develop our alternative opex forecast for the next period. As a result, a separate step change adjustment would only be appropriate where there is a new or changed obligation, or where there is a material change in circumstances beyond the control of the service provider. This is not the case in relation to this cost category and this is acknowledged by ActewAGL.[60] We also note that other service provider's access arrangement revision costs are typically part of their recurrent expenditure with no separate step change.[61] For these reasons we do not agree to this re-proposed step change.

### *New tariff strategy implementation (new)*

In its revised proposal, ActewAGL has proposed a step change of $0.77 million that it states results from new obligations regarding tariff reassignment which will arise if the AER maintains its draft decision to approve ActewAGL's tariff reassignment provisions in the 2016-21 access arrangement.[62]

In its revised proposal ActewAGL stated that the changes to the tariff assignment provisions in its 2016-21 access arrangement were proposed to allow its consumers to benefit by applying downward pressure on its network charges over time. It also stated that the changes were intended to encourage new customers to connect to the network and stay connected to the network and to encourage existing customers to use gas in a way that promotes the efficient use of the network (for example by using gas throughout the year rather than only for heating in winter).[63]

ActewAGL stated that it did not identify this step change at the time of its initial proposal because it had assumed that Jemena's new OneSAP system would facilitate bulk customer transfers. It noted that further assessment by Jemena has indicated that this is not the case. ActewAGL stated that, as a result, in order to implement the change from the old tariff structure to the new tariff structure, JAM will need to manually process reassignment requests from existing customers and their retailers on ActewAGL's Distribution's behalf under the DAMs agreement.[64]

ActewAGL developed some high level options to address this issue and its preferred option involves the temporary increase in manual processing of tariff reassignments at

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60 We also note that ActewAGL's revised proposal states that this "proposed step change was not related to a change in regulatory or a change in circumstance". ActewAGL Distribution – Response to the AER's draft decision 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement – 6 January 2016, p. 84.

61 We note also note that retaining access arrangement review costs in base year opex, with no step change, was one of the options ActewAGL presented in its initial proposal, refer to ActewAGL Distribution, 2016-21 access arrangement information Appendix 5.04 Step changes report, June 2015, option 3 on p. 40.

62 AER, *Draft Decision, ActewAGL Distribution Access Arrangement 2016 to 2021, Attachment 10 – Reference tariff setting*, November 2015, p. 10-6.

63 ActewAGL, *Response to the AER's draft decision, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, January 2016, p. 86.

64 ActewAGL, *Response to the AER's draft decision, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, January 2016, p. 86.

an estimated net benefit of $3.2 million. This option involves an additional six FTEs to process approximately 46,000 reassignments in 2016–17. For years 2017-18 to 2020-21 it estimates 0.11 FTE will be required to process approximately 800 reassignments per year. The forecast equates to $0.72 million ($2015-16) in 2016-17 and $0.01 million ($2015-16) in each remaining year of the period.

ActewAGL stated that, without these resources, JAM will not be able to process requested tariff assignments in a timely way and that this would delay or negate the benefit to customers of switching to a more sustainable tariff.

In its submission to the AER on its draft decision, the CCP8 did not support this proposed step change. It considered that within ActewAGL, the business case for introducing new tariff structures would have identified the business benefits and expected increase in demand and revenues flowing from the proposed changes. It views the costs associated with implementing the change (the cost of manual data entry) should be offset by the expected increase in revenue.[65]

We do not agree with ActewAGL that our draft decision to accept its change in tariff structures results in a new or changed obligation. As indicated by ActewAGL, the purpose of the tariff structure change is a response to declining demand on its gas network and is aimed at encouraging new customers to connect to the network (and stay connected to the network) and existing customers to use more gas. It is a discretionary business decision to encourage increased usage of its network that should be funded from within its existing opex. As a result we do not accept this step change.

### *Tariff variation notice - gas quantity audit (new)*

In its initial proposal ActewAGL proposed a revision requiring annual tariff variation notices to include a statement to support the gas quantity inputs. ActewAGL noted this was part of the changes it had made to reflect the new regulatory requirement contained in the AER's 2015 access arrangement for JGN. We accepted these changes in our draft decision for ActewAGL.[66]

In JGN's 2015-20 access arrangement we accepted its proposed mechanism to enable it to introduce or withdraw reference tariffs via an annual tariff variation mechanism rather than through a formal variation of the access arrangement under rule 65 of the NGR. This was so that it could respond in a timely manner to changes in customer preferences that may, for instance, necessitate introducing a new tariff class. The proposal was similar to amendments made to the NER, allowing electricity distributors to make changes to tariff structures via their Tariff Structure Statements without amendments to their revenue determinations.

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65 Consumer Challenge Panel, *Advice to AER from Consumer Challenge Panel sub-panel 8 regarding the AER Draft Decision and ActewAGL Distribution's Revised Access Arrangement 2016-2021 Proposal*, 23 March 2016, p. 3.

66 AER, *Draft Decision ActewAGL Distribution Access Arrangement 2016 to 2021 Attachment 11 – Reference tariff variation mechanism*, November 2015.

However, as part of this change to the JGN access arrangement, the AER required the statement of gas quantity inputs used in the reference tariff mechanism to be independently audited or verified. This was not proposed by JGN and the AER had not previously required an audit of this information. JGN considered the change to be a new regulatory obligation and applied for a step change for the auditing costs. We approved this step change in JGN's final decision.[67]

ActewAGL states that it will incur additional costs ($0.14 million) to meet this new requirement that were not included in its initial opex forecast and therefore it has included a new step change in its revised proposal. ActewAGL also stated the associated costs are not captured in base year opex or the rate of change.[68]

We have included a gas quantity audit step change of $0.14 million ($2015-16) in our total opex forecast. We included it because the requirement to have a statement of gas quantity inputs audited is a new regulatory obligation which is not accounted for in our estimate of base opex or in our forecast rate of change. ActewAGL's forecast is consistent with costings previously proposed by JGN and accepted by us.[69] We are satisfied that this is a reasonable estimate of the costs of complying with the new obligation.

### 7.4.5 Category specific changes

ActewAGL accepted our draft decision, which included category specific forecasts only for those cost categories subject to a 'true-up' adjustment under the annual tariff variation mechanism, that is, UNFT, EIL and UAG.[70] The tariff variation mechanism is designed to pass through to consumers any changes in these costs, either higher or lower. To enable the mechanism to operate, an annual forecast for each of the cost categories is required. Our final forecasts for UNFT, EIL and UAG have been updated to reflect our final customer connections and demand forecasts.

Our final assessment of ActewAGL's proposed IT asset utilisation fee (ITAUF) step change was that this cost category should be treated as a specific forecast. As the costs are non-recurrent, we note that they should not form part of the revealed base opex for the next access arrangement period and should not be included in the operation of the efficiency carryover mechanism that applies for the 2016–21 period. Further information on our assessment is contained in section 7.4.4.

Table 7.7 compares our category specific forecasts with ActewAGL's revised proposal.

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67 AER, *Final decision: Jemena Gas Networks 2015–20, 7 – Operating expenditure*, June 2015, p. 7-25.

68 ActewAGL, *Response to the AER's draft decision, 2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement*, January 2016, p. 88.

69 AER, *Final decision: Jemena Gas Networks 2015–20, 7 – Operating expenditure*, June 2015, pp. 7-25, 7-26.

70 Our draft decision contains further details about these costs and how they are calculated.

## Table 7.7 ActewAGL category specific forecasts and AER final decision ($ million, $2015–16)

| Forecast | 2015–16 | 2016–17 | 2017–18 | 2018–19 | 2019–20 | 2020–21 | Total (2016–21) |
|---|---|---|---|---|---|---|---|
| **ActewAGL** | | | | | | | |
| UNFT | 5.7 | 6.2 | 6.5 | 6.8 | 7.1 | 6.9 | 33.5 |
| UAG | 1.6 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 7.6 |
| EIL | 0.8 | 0.6 | 0.5 | 0.5 | 0.5 | 0.5 | 2.7 |
| Total | 8.1 | 8.3 | 8.6 | 8.8 | 9.1 | 8.9 | 43.7 |
| **AER decision** | | | | | | | |
| UNFT | 5.7 | 6.2 | 6.5 | 6.7 | 7.0 | 6.9 | 33.3 |
| UAG | 1.6 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 7.6 |
| EIL | 0.8 | 0.6 | 0.5 | 0.5 | 0.5 | 0.5 | 2.7 |
| ITAUF | 0.1 | 0.9 | 0.9 | 0.8 | 0.8 | 0.7 | 4.2 |
| Total | 8.2 | 9.2 | 9.4 | 9.6 | 9.9 | 9.6 | 47.7 |

Source: ActewAGL Distribution - Revised 2016-21 access arrangement proposal - Appendix 7.01 Revised proposal opex model - January 2016; AER analysis. Numbers may not add due to rounding.