ActewAGL

ActewAGL Distribution

Response to the AER's draft decision

2016-21 ACT, Queanbeyan and Palerang Gas Network Access Arrangement

January 2016

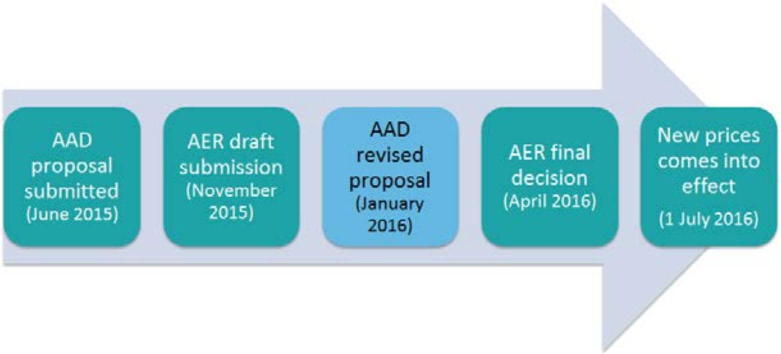
Table of contents

List of tables

Key highlights

Context of this revised proposal

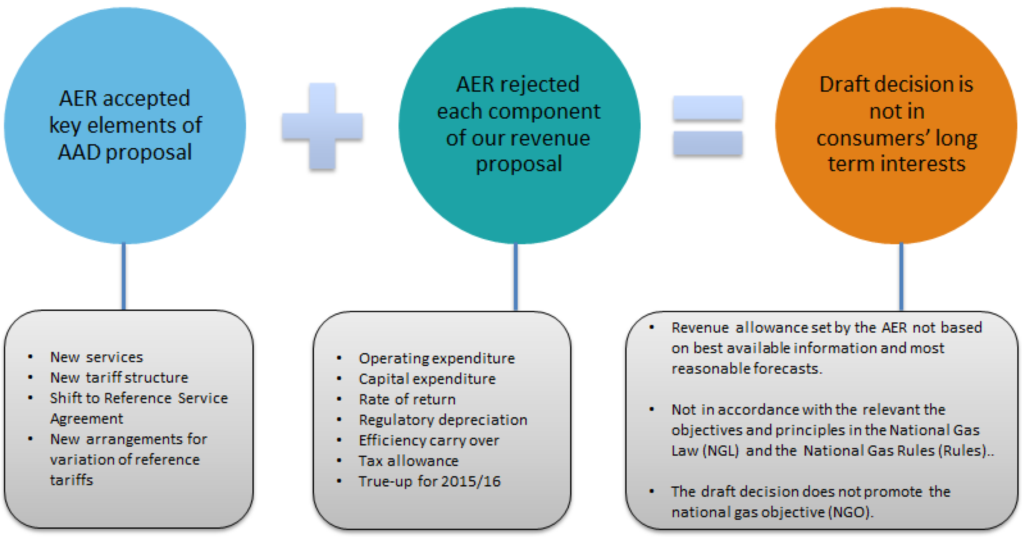
The process for approval and implementation of gas distribution access arrangements typically takes around 12 months. We are in the middle of this process, as shown in the green shaded box within the figure below illustrating the regulatory timetable.



In June 2015 we submitted our 2016-21 access arrangement proposal to the Australian Energy Regulator (AER). The proposal was:

- Developed in consultation with external stakeholders.
- Designed to meet all regulatory requirements and obligations
- Intended to continue to provide the safe, reliable and efficienctly priced services that our customers demand.

The AER released its draft decision on 26 November 2015. While the draft decision accepted many elements of our proposed access arrangement, we consider that the draft decision is not in consumers' long term interests, as summarised below.

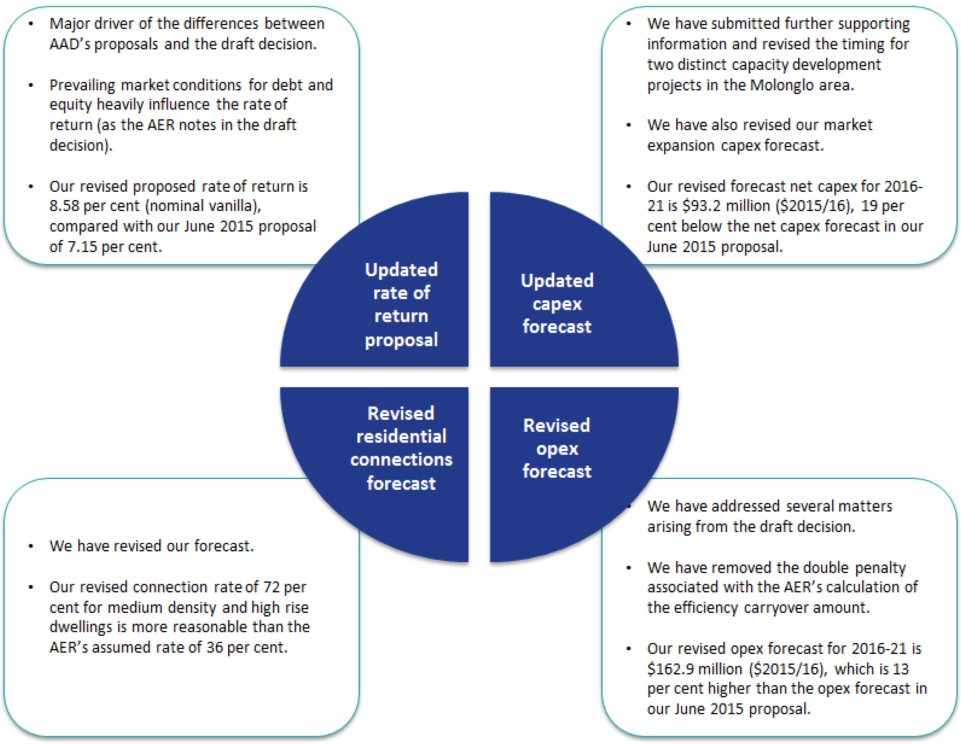


Key revisions

Our revised access arrangement proposal addresses the matters arising from the draft decision and incorporates updates to ensure that the proposal is based on the best available information and the most reasonable forecasts.

Each element of our revised proposal is in accordance with the objectives, principles and requirements in the NGL and the Rules. Overall our revised proposal will promote consumers' long term interests with respect to reliability, security and safety and is preferable to the draft decision in contributing to the achievement of the NGO. The basis for this conclusion is summarized in the Overview to this Response to the draft decision and details are provided in the chapters that follow.

What revisions have we proposed



We have adopted several of the AER's required revisions. For example, we have accepted the draft decision requirement to apply a revenue reconciliation (or true-up) for the extension year, 2015/16. This reduces our forecast revenue requirement for 2016-21 by $5.0 million (nominal).

What does this mean for our stakeholders and consumers

Our revised forecast revenue requirement (unsmoothed) for 2016-21 is $390.8 million (nominal), which is 9 per cent higher than the forecast revenue requirement in our June 2015 proposal and 30 per cent higher than the draft decision revenue allowance. The higher return on capital accounts for more than half of the revenue difference between the draft decision and our revised proposal. Our revised proposal involves a 3.78 per cent average real price increase in 2016/17 followed by CPI increases for the remaining four years of the access arrangement period.

1 Introduction

ActewAGL Distribution is the licenced provider of gas distribution and connection services in the ACT, Queanbeyan and the Palerang Shire. An access arrangement sets out the tariffs, terms and conditions for access to gas services provided by us over the 5-year period from 1 July 2016. The Australian Energy Regulator (AER) is responsible for reviewing our proposed access arrangement, within the framework provided by the National Gas Rules (Rules) and the National Gas Law (NGL).

1.1 Background

1.1.1 ActewAGL Distribution's access arrangement proposal

On 30 June 2015 we submitted to the AER our proposed *Access arrangement for the ACT, Queanbeyan and Palerang gas distribution network 1 July 2016 to 30 June 2021* (**access arrangement proposal**) as well as our access arrangement information and associated models and supporting documents. These documents together comprise our **June 2015 submission**.

Our access arrangement proposal was originally scheduled to be submitted by 30 June 2014.[1] However, in accordance with transitional provisions for the amendments to the Rules, released by the Australian Energy Market Commission (AEMC) in November 2012, the AER exercised its power to extend the review submission date by 12 months to 30 June 2015.[2] The AER confirmed, by letter to ActewAGL Distribution, that the current access arrangement period would be treated as a six-year period.[3] Accordingly, the next access arrangement period was to commence on 1 July 2016 and end on 30 June 2021.

1.1.2 The review process

The AER published our access arrangement proposal and associated material on its website on 10 July 2015 and invited public submissions. Twelve public submissions have been posted on the AER website.

Following the June 2015 submission we:

[1] The review submission date specified in our 2010-15 access arrangement is 30 June 2014.

[2] Letter from the AER dated 4 July 2014. The transitional Rules gave the AER discretion to extend the period for submitting the access arrangement revision proposal under Rule 52 by up to 18 months (clause 34 of schedule 1 to the Rules) and required it to exercise its power under Rule 52(3) (as modified by clause 34 of Schedule 1 to the Rules) to extend that period to 30 June 2015 (clause 35(3) of Schedule 1 to the Rules). ActewAGL Distribution did not seek the additional 6 months extension.

[3] Letter from the AER dated 24 November 2014.

- gave presentations to the AER Board and the AER's Consumer Challenge Panel sub-panel 8 (CCP8);
- continued to engage with our Energy Consumer Reference Council (ECRC), providing updates on the AER's review and opportunities for discussion; and
- responded to 42 AER information requests, containing more than 170 questions.

The AER published the *Draft decision, ActewAGL access arrangement 2016 to 2021 (***draft decision**) on 26 November 2015. The draft decision includes, in each of the attachments, the AER's required revisions to the access arrangement and the access arrangement information.

The AER indicated in the draft decision that revisions to the access arrangement proposal must be submitted by 6 January 2016. The AER also indicated that stakeholder submissions will close on 4 February 2016.

Revisions of an access arrangement proposal in response to a draft decision by the AER are governed by Rule 60 which specifies that:

1. The service provider may, within the revision period, submit additions or other amendments to the access arrangement proposal to address matters raised in the access arrangement draft decision.
2. The amendments must be limited to those necessary to address matters raised in the access arrangement draft decision unless the AER approves further amendments.
3. If the service provider submits amendments to the access arrangement proposal, the service provider must also provide the AER (together with the amendments) a revised proposal incorporating the amendments.

1.2 Structure of our revised proposal and response to the draft decision

ActewAGL Distribution has reviewed the AER's draft decision and submits:

- a revised access arrangement proposal (comprising marked-up and clean versions of the access arrangement, including the Reference Service Agreement (RSA));
- a revised access arrangement information, which contains the information specified in Rule 72(1);
- revised models; and
- this document, which provides our response to the draft decision and an explanation of the revisions we have made to our access arrangement proposal (see further details below on the purpose and structure of this document).

We will also submit, by 4 February 2016, further supporting material. Ideally, we would have submitted all supporting material with our revised proposal. However, the relatively short revision period the AER has allowed has meant that this is not possible.[4] As previously raised with the AER, we consider that the AER's timetable does not promote the national gas objective (NGO) and it fails to afford all parties a reasonable opportunity to respond to the AER's draft decision.[5]

1.3 Purpose and structure of this document

In this *Response to the draft decision (Response)* we:

- Provide our responses to the draft decision. As noted in the section above, further supporting material will be provided by the 4 February 2016 deadline for submissions.
- Address each of the required revisions in the draft decision and explain where and how we have amended the access arrangement proposal and access arrangement information to address matters raised in the draft decision;
- Describe the other amendments (other than those directly arising from the revisions required by the AER) we have made to the access arrangement, access arrangement information and associated models – for example updates to account for changes in our circumstances since the June 2015 submission.

A full list of the AER's required revisions and ActewAGL Distribution's responses is provided in appendix 2.01 of this *Response*.

This *Response* is structured as follows:

- Chapter 2 contains an overview of our responses to the key elements of the draft decision and our assessment of the decision as a whole.
- Chapters 3 to 14 contain our responses on specific elements of the draft decision and explanations of the revisions we have made to the access arrangement and the access arrangement information. Where we have not adopted the AER's required revisions, these chapters also contain explanations of why we have not adopted the revisions. The structure broadly follows the structure of the draft decision:
    - services covered by the access arrangement
    - capital base, including regulatory depreciation
    - rate of return, gamma and inflation
    - capital expenditure

[4] The time allowed by the AER for ActewAGL Distribution to respond to the draft decision is substantially less than the revision period in the AER's most recent gas access arrangement review process (being the review of the access arrangement proposal submitted by Jemena Gas Networks (NSW) Ltd (JGN) for the 2015-2020 access arrangement period). In that process, the AER allowed JGN a revision period of 62 business days, more than twice what the AER has allowed for ActewAGL Distribution.

[5] This matter was raised in a meeting between ActewAGL Distribution and the AER Board on 21 August 2015 and in an ActewAGL Distribution letter to the AER dated 26 August 2015.

- operating expenditure
- corporate income tax
- efficiency carryover mechanism
- reference tariff setting
- reference tariff variation mechanism
- non-tariff components
- demand.

In appendix 2.01 to this *Overview* we provide a summary table indicating whether we have accepted, not accepted or partially accepted each revision and providing a cross reference to an explanation in the relevant chapters.

Appendices to this *Response* provide further details on key elements of our response and revisions.

2 Overview

In this chapter we provide an overview of our response to the draft decision and our revised proposal. We also explain why our revised proposal is in the long term interests of consumers and preferable to the AER's draft decision in terms of contributing to the achievement of the national gas objective (NGO) to the greatest degree. In the following section we briefly describe the framework we have used to develop our June 2015 access arrangement proposal and our revised access arrangement proposal and assess the AER's draft decision.

2.1 Long term interests of consumers and the national gas objective (NGO)

We have developed our access arrangement proposal, assessed the AER's draft decision and have prepared our revised proposal within the framework provided by the NGL and the Rules. We have also been guided by the feedback we have received, through our ongoing consumer engagement program, on what is important to consumers and what changes they want and support.

The NGL provides the foundation objective and the principles for the regulation of gas network access arrangements. The NGO, contained in section 23 of the NGL, is:

> *… to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.*

In making a decision on a gas access arrangement the AER must comply with a number of obligations imposed by the NGL that have the object of ensuring that the AER makes a decision that contributes the achievement of the NGO to the greatest degree. In making an access arrangement decision, section 28 of the NGL provides that the AER must:

- perform or exercise a function or power under the NGL or the Rules that relates to the making of an access arrangement decision in a manner that will or is likely to contribute to the achievement of the NGO;[6]
- take into account the revenue and pricing principles when exercising a discretion in approving or making those parts of an access arrangement relating to reference tariffs;[7]
- specify the manner in which the constituent components of the decision relate to each other and the manner in which that interrelationship has been taken into account in the making of the decision;[8] and

[6] NGL, section 28(1)(a) and section 2(1) definition of 'AER economic regulatory function or power'.

[7] NGL, section 28(2)(a).

[8] NGL, section 28(1)(b)(ii), section 2(1) definitions of 'designated reviewable regulatory decision', 'applicable access arrangement decision' and 'full access arrangement decision', and section 244 definition of 'reviewable regulatory decision'.

- if there are two or more decisions that will or are likely to contribute to the achievement of the NGO:
    - make the decision that it is satisfied will or is likely to contribute to the achievement of the NGO to the greatest degree (the NGO preferable decision); and
    - specify the reasons as to the basis on which the AER is satisfied that the decision it has made is the NGO preferable decision.[9]

Further, on review of the AER's decision on an access arrangement, the Australian Competition Tribunal (Tribunal) can only make a determination to vary or set aside the AER's decision (and remit the matter back to the AER), if it satisfied that to do so will, or is likely to result in a decision that is materially preferable to the AER's decision in making a contribution to the achievement of the NGO (materially preferable NGO decision).[10]

The NGO is an economic concept which requires the promotion of efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas. The concept of economic efficiency encompasses three dimensions: productive efficiency, allocative efficiency and dynamic efficiency. In the context of gas pipeline services this means:

- delivering services at the lowest sustainable cost (productive efficiency);
- providing the services that consumers value highest, and setting prices to reflect the underlying costs of supplying each service (allocative efficiency); and
- responding to changing market conditions, opportunities, technology and consumer preferences over time (dynamic efficiency).

The specific reference in the NGO to the interests of consumers in the 'long term', and the reduced emphasis it implies for short term considerations, further implies that the NGO will be promoted if decisions are made that give lesser weight to near term productive and allocative efficiency gains and greater weight to long term productive and allocative efficiency considerations (that is, to the long term, dynamic aspect of efficiency).

The phrase 'long term' is concerned with the period over which the full effects of the AER's decision will be felt.[11] The comments of the Tribunal on the phrase 'long term' in considering the

[9] NGL, section 28(1)(b)(iii), section 2(1) definitions of 'designated reviewable regulatory decision', 'applicable access arrangement decision' and 'full access arrangement decision', and section 244 definition of 'reviewable regulatory decision'.

[10] NGL, 259(4a). Division 1 of Part 5 of the NGL provides for merits review by the Tribunal of 'reviewable regulatory decisions', which include 'designated reviewable regulatory decisions' and therefore would include the AER's decision on our access arrangement.

[11] *Re Seven Network Limited (No 4)* [2004] ACompT 11 at [120]; *Application by Chime Communications Pty Ltd (No 2)* [2009] ACompT 2 at [15], in discussing the objective of Part XIC of the *Trade Practices Act 1974* (Cth) (now the *Competition and Consumer Act 2010*), being the long term interests of end-users', on which the NGO was modelled.

objective of Part XIC of the *Trade Practices Act 1974* (Cth) (now the *Competition and Consumer Act 2010* (Cth), being the 'long term interests of end-users', are especially pertinent. The Tribunal observed:[12]

> *In considering how these elements may combine, it may be the case, for example, that very low prices are in the short-term interests of end-users. Over the long-term, however, sustainably low prices (which may be higher than the "very low prices" referred to above) are more likely to enhance their interests, as the long-term interests of end-users are likely to suffer in an environment characterised by short-lived operators who fall over soon after the customer signs with them, as distinct from one in which reliable service-providers offer competitive, but sustainable, services. Moves that enhance the quality and diversity of service may be subject to a similar analysis.*

The NGO is therefore concerned with the long term interests of consumers in sustainably low prices and the maintenance or enhancement of quality, safety, reliability and security of supply, rather than the pursuit of price reductions in the short term at the expense of their other interests. Short term price reductions that cannot be sustained may result in outcomes that are contrary to consumers' long term interests.

The Tribunal has recognised that:

- the long term interests of consumers requires prices to reflect the long run cost of supply and to support efficient investment by providing investors with a return which covers the opportunity cost of capital required to deliver the relevant services;[13] and
- consumers will benefit in the long run if resources are used efficiently, i.e. if investors receive a return on efficient investment which covers the opportunity cost of the capital required to deliver the services. While consumers might benefit today from the lowest possible prices which do not provide an adequate return on investment, such prices are not in their long term interest. If those prices are sustained, they would not generally support the allocation of sufficient resources including capital, to maintain and increase the supply of the affected service in accordance with the value the consumers place on it. This would be contrary to the promotion of efficient investment in the long term interest of consumers.[14]

While the Tribunal made these comments in the context of discussing the national electricity objective (NEO) in section 7 of the National Electricity Law, that objective is substantively similar to the NGO, and these principles apply equally to the NGO.

The NGO operates together with the revenue and pricing principles in section 24 of the NGL. Further, as noted above, the NGL expressly requires the AER to take those principles into account

[12] *Re Seven Network Limited (No 4)* [2004] ACompT 11 at [121].

[13] *Re Application by ElectraNet Pty Limited (No 3)*[2008] ACompT 3 at [15]; *Application by EnergyAustralia and Others* [2009] ACompT 8 at [18].

[14] *Re Application by ElectraNet Pty Limited (No 3)* [2008] ACompT 3 at [251].

when exercising a discretion in approving or making those parts of an access arrangement relating to reference tariffs. The revenue and pricing principles are:

(2) A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in—

- *a) providing reference services; and*
- *b) complying with a regulatory obligation or requirement or making a regulatory payment.*

(3) A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes—

- *a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and*
- *b) the efficient provision of pipeline services; and*
- *c) the efficient use of the pipeline.*

(4) Regard should be had to the capital base with respect to a pipeline adopted—

- *a) in any previous—*
  - *(i) full access arrangement decision; or*
  - *(ii) decision of a relevant Regulator under section 2 of the Gas Code;*
- *b) in the Rules.*

(5) A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services.[15]

The Rules contain further detailed requirements for access arrangements, including prescribing the use of a building block approach for the determination of allowed revenue and the manner in which the AER is to determine the various building blocks.[16] The Rules also include a specific allowed rate of return objective (ARORO).[17]

[15] NGL section 24(2)-(7).

[16] Rules, Part 9, Division 3.

[17] Rules, clause 87(2)(3).

It must be assumed that the Rules with respect to the making of an access arrangement are intended to contribute to the achievement of the NGL and are consistent with the revenue and pricing principles. The reasonableness of this assumption is underlined by the role of the NGO and the revenue and pricing principles in the making of the Rules. In particular, the Australian Energy Market Commission (AEMC) may only make a Rule if it is satisfied that to do so will or is likely to contribute to the achievement of the NGO[18] and, in making a Rule with respect to the regulatory economic methodologies to be applied by the AER in approving revisions or a variation to an applicable access arrangement that is a full access arrangement, the AEMC must also take into account the revenue and pricing principles.[19] Further, the AEMC may make a Rule that is different to a market initiated Rule if it is satisfied that the Rule will or is likely to better contribute to the achievement of the NGO.[20]

The building block approach to determining revenue allowances for an access arrangement, specified in clause 76 of the Rules, in particular, is constructed to ensure recovery by service providers of at least efficiently and prudently incurred costs, facilitating ongoing investment and promoting dynamic efficiency. In addition to the expert reports we provided with our June 2015 submission in support of our construction of the NGO,[21] we are including with our revised proposal expert reports expressing similar views in respect of the NEO.[22] As noted above, the NGO and the NEO are substantively similar, and the building block approach is common to both the Rules and the National Electricity Rules.

The building block approach and the revenue and pricing principles in the Rules and NGL respectively provide the essential elements of a framework of economic regulation that is capable of achieving the NGO. The building block approach and the revenue and pricing principles are designed to ensure that the AER's decisions will further the NGO by ensuring that each of the three dimensions of efficiency encapsulated in the NGO are advanced.

It follows that a failure to give effect to each and every building block or to comply with each of the revenue and pricing principles will invariably compromise the achievement of the NGO. In contrast, an access arrangement decision that properly applies the building block approach in the Rules, with each of the building blocks determined in accordance with the Rules, and is also consistent with the revenue and pricing principles will further the NGO by providing sustainable revenues that are sufficient to ensure the quality, safety, reliability and security of supply of

[18] NGL, section 291(1).

[19] NGL, section 293, and item 40 of Schedule 1 to the NGL.

[20] NGL, section 296.

[21] G Houston, *Evaluation of the ERA Draft Decision against the National Gas Objective*, 27 November 2014 (Appendix O.02 to our June 2015 submission); J Swier, *Economic consideration for the interpretation of the National Gas Objective*, 23 May 2014 (Appendix O0.03 to our June 2015 submission).

[22] HoustonKemp, *AER determination for ActewAGL Distribution - contribution to NEO and NEO preferable decision*, 13 February 2015; HoustonKemp, *AER preliminary decision for Energex - contribution to NEO and NEO preferable decision* 3 July 2015.

natural gas in the long term interests of consumers, while at the same time serving the long term interests of consumers with respect to price.

In addition, a reviewable regulatory decision (including an access arrangement decision) made by the AER that is not in accordance with law cannot be said to contribute to the achievement of the NGO.[23] Further, a decision that does not comply with the Rules or other legal requirements is not a 'possible' decision for the purposes of section 259(4a) of the NGL. Rather, a decision is properly said to contribute to the achievement of the NGO to the greatest degree where, in the event that a range of decisions exist that are in accordance with law, it is to be preferred on the basis that it makes the greatest contribution to the achievement of the NGO. Our June 2015 submission included a detailed explanation of how each of the elements of the proposal and the proposal as a whole are in the long term interests of consumers and addressed all the relevant objectives, principles and requirements in the NGL and the Rules. We also identified the interrelationships between elements of our proposal.[24]

We have also assessed the draft decision from the perspective of whether it furthers the NGO and is consistent with the revenue and pricing principles in the NGL and the requirements set out in the Rules. For the reasons set out in the sections below, and the following chapters, the AER's draft decision does not contribute to the achievement of the NGO to the greatest degree. Table 2.2 at the end of this *Overview* provides a summary of why we consider that our revised proposal is to be preferred in terms of promoting the NGO.

2.2 ActewAGL Distribution's access arrangement proposal (June 2015)

Our overarching objective in developing the June 2015 access arrangement proposal was to promote the long term interests of consumers. Our proposal included several changes to the services offered, tariff structures and terms and conditions in the 2010-15 access arrangement. These were designed to allow ActewAGL Distribution to:

- Better tailor its services and tariff offers to meet the needs of our customers;

[23] This is also evident from a consideration of the SCER's policy statements regarding the establishment of the materially preferable NGO decision requirement for the grant of relief by the Tribunal on review (see section 259(4a) of the NGL) that a reviewable regulatory decision, including an access arrangement decision made by the AER, that is not in accordance with law cannot be said to contribute to the achievement of the NGO or, thus, constitute a decision that is likely to contribute to the achievement of the NGO to the greatest degree for the purposes of section 28(1)(b)(iii) of the NGL. See SCER, *Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper,* 6 June 2013, pp. 9 to 10. SCER, *Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper,* 6 June 2013 is 'Law extrinsic material' for the purposes of clause 8 of Schedule 2 to the NGL, being 'relevant material not forming part of this Law'. Accordingly, regard may permissibly be had to it in interpreting the requirement in section 28(1)(b)(iii) of the NGL to the extent that requirement is ambiguous or obscure or its ordinary meaning leads to a result that is manifestly absurd or unreasonable, or to confirm the interpretation conveyed by the ordinary meaning of the provision (NGL, Schedule 2, clause 8(2)). See also *Application by Energex Limited (No 4)* [2011] ACompT 4 at [21]-[22].

[24] ActewAGL Distribution 2015, *Access arrangement information, Overview*, June, section 1.8, p. 38.

- Respond to changing consumer behaviour, gas markets and regulatory requirements; and,
- More closely align the access arrangement with approved access arrangements for other networks, and particularly the New South Wales network of Jemena Gas Networks (JGN).

Our proposal included a forecast revenue requirement for 2016-21 of $332.9 million ($2015/16), which is only one per cent higher (in real terms) than the AER allowance for 2010-15. This is the forecast revenue required for ActewAGL Distribution to:

- continue to deliver the safe and reliable services that consumers have said they want;
- meet expected growth in connections;
- manage the network in a sustainable way; and,
- meet all relevant regulatory obligations and requirements.

The proposal was underpinned by detailed opex and capex proposals which recognise the need to take a long term perspective in managing the network, optimising the use of existing assets and investing to accommodate efficient growth in connections. The proposals were also based on a detailed understanding of the specific circumstances of our network and the changing needs and preferences of our customers.

2.3 The AER's draft decision

In the draft decision the AER has accepted several key elements of our access arrangement proposal. The AER has:

- Accepted our simplified service structure and new reference tariff structure;
- Accepted our proposed move to a single Reference Service Agreement (RSA), to replace the current Gas Transport Agreements; and,
- Accepted our proposal to move from a fixed tariff schedule to a weighted average price cap (WAPC).

However, the AER has not accepted our revenue and pricing proposals and has instead adopted forecasts for the revenue building blocks which result in a revenue requirement for the 2016-21 access arrangement period which is 22 per cent below our proposal. The key drivers of the differences between our proposal and the AER's draft decision are summarized below.

2.3.1 Revenue requirement

In the draft decision the AER has rejected each of our proposed building block elements. The AER has:

- Rejected our proposed weighted average cost of capital (WACC) of 7.15 per cent and replaced it with a WACC of 6.09 per cent;[25]
- Rejected our proposed gamma of 0.25 and replaced it with gamma of 0.40;
- Rejected our forecast opex of $146.2 million ($2015/16) and replaced it with its forecast of $134.1 million, an 8.3 percent reduction;
- Rejected our forecast net capex of $117.5 million and replaced it with its forecast of $76.8 million, a 38.9 per cent reduction;
- Rejected our proposed efficiency carryover amount for 2016-21 of $11.7 million and instead calculated a carryover amount for 2016-21 of $1.4 million; and
- Applied a revenue reconciliation (true-up) for 2015/16, on the basis that there is an interval of delay and the AER is "required" to apply this adjustment.[26]

2.3.2 Demand and tariffs

In the draft decision the AER has:

- Accepted our proposed demand forecast for the Tariff D market (both MDQ and ACQ)
- Rejected our proposed demand forecast for the Tariff V market (customers up to 10 GJ p.a.) and replaced it with a demand forecast which is 0.9 per cent lower than our proposal over the 2016-21 period. In adopting the lower demand forecast the AER has rejected both our connection forecast and our forecast consumption per connection.

The AER has not accepted our proposed X factors for the period or our proposed schedule of initial tariffs.

2.3.3 Non-tariff elements

The AER has accepted most of the non-tariff elements of our 2016-21 access arrangement proposal. However the draft decision requires revisions to:

- The RSA in relation to ActewAGL Distribution's discretion and the arrangements for bulk transfer of customers and; and
- The extensions and expansions policy in the access arrangement.

2.4 Overview of our response to the draft decision

ActewAGL Distribution acknowledges the AER's acceptance of several key elements of its access arrangement proposal. We also accept some of the AER's required revisions, and we have therefore adopted them in our revised proposal. For example, we have accepted some of the

---

25 To be updated annually for the return on debt

26 AER 2015, *ActewAGL Distribution 2016-21 access arrangement, Draft decision, Overview*, November, p. 13

AER's required revisions to the RSA. We have also accepted the AER's draft decision that the efficiency carryover mechanism (ECM) should be applied in a way that provides a continuous incentive (including over 2015/16, the extension year).

However, we do not agree with the AER's draft decision on each of the revenue building blocks and we have prepared a revised proposal in response.

An overview of our revised proposal is provided in section 2.6 below. Our detailed responses to each element of the draft decision are provided in the following chapters of our response to the AER's draft decision.

2.5 Our approach to the 2015/16 extension year

In our June 2015 submission we explained in detail our position that the extension year, 2015/16, does not constitute an interval of delay and there is therefore no basis in the Rules for the AER to perform a true-up (or revenue reconciliation). The AER did not engage with our reasoning in the draft decision. We therefore maintain our view.

Nevertheless, in our revised proposal we have accepted that a true-up be applied for 2015/16.

We maintain our position that our proposed approach and revised parameters should be used to calculate the value of the true-up.[27] These are shown in our revised proposed revenue and explained in our revised access arrangement information (chapter 12). Our revised value for the true-up is $5.0 million, as shown in Table 2.1 below.

In the draft decision the AER states several times that ActewAGL Distribution requested the delay of 12 months i.e. the extension year, 2015/16.[28] However, the AER does not explain the background which led to the inclusion of a transitional amendment to Rule 52(3) for ActewAGL Distribution, thereby creating a misleading impression.

When the AEMC was consulting on the implementation of the then proposed 2012 amendments to the Rules, including the proposed transitional provisions, we made two written submissions to the AEMC. In those submissions to the AEMC, we did not support the transitional arrangements. We argued that the original regulatory review timetables should be maintained (for both our gas network and our electricity network) to avoid the uncertainty and costs associated with changing arrangements at a late stage.[29] However, the AEMC decided to delay the electricity reset by 12 months. That decision resulted in ActewAGL Distribution being involved in two reset processes simultaneously. Given ActewAGL Distribution's small size that position would have resulted in serious resourcing issues and so we were compelled to request an extension for the gas

[27] In contrast to the National Electricity Rules which include explicit provisions for a true-up of revenues following the transitional year (2014/15) (see Rules 11.56.4(h) - (j)), the Rules for gas do not include any specific requirements or provisions for revenue adjustments following the extension year.

[28] AER 2015, *Overview to the draft decision*, p. 17 and Appendix B.

[29] ActewAGL Distribution, Submissions to the AEMC on draft transitional arrangements for ACT/NSW distribution service providers, 25 October 2012 and 16 November 2012.

submission date (to avoid a direct clash of the two processes). We did not voluntarily make the request.

2.6 ActewAGL Distribution's revised access arrangement proposal

Revisions consistent with the AER's draft decision

ActewAGL Distribution accepts some of the AER's required revisions and we have therefore adopted these in our revised proposal. Key AER revisions that we have accepted include:

- The AER's formulae for calculating the efficiency carryover amount (which involves a continuous incentive, instead of the stop/start approach we proposed in the June 2015 submission);
- Several changes to the RSA;
- Removal of some cost pass through events;
- Application of a revenue reconciliation (true-up) for 2015/16 (however, we maintain our position that our proposed approach (and revised parameters) should be used to calculate the value of the true-up);
- The consumption per connection forecasts for the Tariff V market;
- Debt raising transaction costs of 9.92 bppa;
- Adoption of the SL CAPM model to estimate return of equity (although with parameters suitably modified).

Revisions that are consistent with our June proposal or reflect the NGO to the greatest degree

We have a number of concerns with the AER's draft decision. As a result, we have explained why the original proposal, or additional revisions contained in this revised proposal, promotes the NGO to the greatest degree.

Our main concerns, and resulting revisions to our proposal, are as follows.

- The draft decision on the **rate of return, gamma and inflation** does not provide for an overall return that is consistent with the NGO and the ARORO.
    - As a result, we have updated our rate of return proposal – we have revised our proposal to reflect the latest relevant market parameters and to ensure that it achieves the ARORO and the NGO to the greatest degree. Our revised proposal is aligned with our proposal for our electricity network, which is currently being considered by the Australian Competition Tribunal. In our June submission we proposed a rate of return (nominal vanilla) of 7.15 per cent. Our revised rate of return (nominal vanilla) for the 2016-21 access arrangement period is 8.58 per cent.
- The **forecast capex** adopted by the AER in the draft decision is not based on the best available information and estimates. The forecast capex is not sufficient to give

ActewAGL Distribution a reasonable opportunity to recover the costs of connecting new customers and maintaining safe and reliable services.

- We have updated our capex proposal – in particular we have developed a more granular forecast for the medium density market expansion and retimed two distinct capacity development projects in the Molonglo area based on an updated new dwelling forecast. Our revised capex is necessary to ensure that we are able to promote the long term interests of consumers in the ACT. In our June submission our forecast net capex for 2016-21 was $115.7 million ($2015/16). Our revised proposed net capex is $93.2 million ($2015/16).

- The **forecast opex** adopted by the AER in the draft decision does not include the costs associated with step changes necessary to enable us to recover our efficient costs, is based on unreasonable assumptions about productivity growth and output growth, and does not correctly set the base year allowance.
  - Hence, we have revised our opex forecast – we have revised our forecast to address several matters arising from the draft decision (for example we have revised our forecasts for output growth and productivity growth). We have also updated our step change proposals to address changes in our circumstances since the June 2015 submission. Our revisions are necessary to ensure that we are able to fully recover the efficient costs of delivering our services and meeting our regulatory requirements and obligations. In our June submission our forecast opex for 2016-21 was $157.9 million ($nominal). Our revised opex forecast is $175.2 million.

- The **efficiency carryover amount** and **forecast opex** calculated do not correctly reflect the inter-relationship between these two elements and result in an excessive penalty which is inconsistent with the objective of the ECM to share efficiency gains and losses fairly between network service providers and network users. The incorrect application of the ECM would jeopardise the continuous and time invariant incentives to achieve opex efficiency gains that the ECM is designed to deliver.
  - Therefore, we have revised the ECM carryover amounts – our revised opex base year does not exclude non-recurrent costs to ensure the principles for the ECM (as set out in the AER's guidelines regarding the efficiency benefit sharing scheme[30]) are achieved. We have also corrected some errors in the AER's calculation (which were in our favour). These revisions are necessary to ensure that the ECM provides continuous incentives for efficiency improvements and a fair sharing of efficiency gains and losses, as intended by the AER's guideline.[31] Our revised efficiency carryover amount for 2016-21 is -$6.4 million (nominal), compared with our June proposal of +$11.7 million (nominal).

[30] AER 2013, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November

[31] AER 2013, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November

- The overall **revenue allowance** is not sufficient to provide ActewAGL Distribution with a reasonable opportunity to recover at least its efficient costs of providing pipeline services and meeting its relevant obligations (as required by the revenue and pricing principles in the NGL). We have calculated a revised forecast revenue requirement of $390.8 million (unsmoothed, nominal) which satisfies all the requirements of the Rules and the NGL.

Table 2.1 provides a comparison of our June 2015 proposal, the AER's draft decision and our revised proposal.

Table 2.1 Draft decision and revised proposal building blocks ($million, nominal)

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total 16/17 – 20/21
Return on capital	Proposal		26.3	27.7	29.4	30.9	32.4	146.7
	Draft decision	20.6	22.2	23.1	23.9	24.6	25.1	118.9
	Revised proposal	29.2	31.3	32.6	33.8	35.0	36.3	169.0
Regulatory depreciation	Proposal		4.1	4.7	5.5	6.5	7.4	28.2
	Draft decision	3.7	4.3	5.0	5.8	6.6	7.5	29.1
	Revised proposal	4.4	5.4	6.2	7.0	7.9	8.8	35.2
Opex	Proposal		28.4	29.2	30.8	34.7	34.8	157.9
	Draft decision	24.8	26.8	27.7	28.7	30.2	31.2	144.6
	Revised proposal	29.9	32.3	32.6	33.9	38.4	38.1	175.2
ECM carryover amounts	Proposal		6.2	3.2	2.3	-	-	11.7
	Draft decision	1.5	3.7	0.6	-0.4	-2.6	0.0	1.3
	Revised proposal	-0.4	1.8	-1.3	-2.4	-4.6	0.0	-6.4
Tax allowance	Proposal		2.6	2.8	3	3.2	3.4	15.0
	Draft decision	1.1	1.2	1.3	1.4	1.5	1.6	7.2
	Revised proposal	2.2	2.6	3.3	3.8	4.0	4.1	17.8
Revenue requirement (unsmoothed)	Proposal		67.6	67.5	71.0	75.4	77.9	359.4
	Draft decision	51.8	58.4	57.7	59.4	60.3	65.3	301.0
	Revised proposal	**65.4**	**73.5**	**73.4**	**76.1**	**80.7**	**87.3**	**390.8**
Revenue requirement (smoothed)	**Proposal**		69.3	70.3	71.4	72.9	74.5	358.4
	Draft decision	70.1	53.1	54.4	55.7	57.2	58.8	279.1
	Revised proposal	**70.4**	**74.4**	**75.3**	**76.4**	**77.6**	**79.0**	**382.6**
Revenue reconciliation	Proposal (alternative model)	-9.6	n/a	n/a	n/a	n/a	n/a	n/a
	Draft decision	-18.3	n/a	n/a	n/a	n/a	n/a	n/a
	Revised proposal	-5.0	n/a	n/a	n/a	n/a	n/a	n/a
X factors (CPI-X)	**Proposal**		2.23%	0.00%	0.00%	0.00%	0.00%	n/a
	Draft decision	2.44%	25.68%	-1.00%	-1.00%	-1.00%	-1.00%	n/a
	Revised proposal	2.14%	-3.78%	0.00%	0.00%	0.00%	0.00%	n/a

		Other AAI elements						
		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total 16/17 – 20/21
Net capex, ($15/16)	Proposal		22.4	26.6	24.5	24.1	18.1	115.7
	Draft decision	29.5	17.5	16.9	16.1	12.5	13.6	76.6
	Revised proposal	30.8	19.0	18.5	19.4	20.2	16.1	93.2
WACC (nominal vanilla)	Proposal		7.15%	7.15%	7.15%	7.15%	7.15%	n/a
	Draft decision	6.09%	6.09%	6.09%	6.09%	6.09%	6.09%	n/a
	Revised proposal	8.64%	8.58%	8.58%	8.58%	8.58%	8.58%	n/a

Our revised proposal includes a revised price path (X factors) and revised initial tariff schedule, based on the revised revenue allowance and revised demand forecast. In developing our revised price path and tariff schedule we have applied the same principles that we applied in developing the June 2015 proposal. These principles take account of the feedback we have received from consumers, particularly through the ECRC, and also the requirements of the Rules and the NGL.

Consistent with the approach we adopted in our June 2015 submission, our price path involves an initial adjustment in 2016/17, followed by CPI increases for the remaining four years of the access arrangement period. This is consistent with the preference of consumers (as discussed in our June 2015 submission)[32] for a stable price path with limited shocks. In contrast, the AER's draft decision price path involves a larger 2016/17adjustment, followed by increases above the CPI for the remaining four years.

Our revised X factor for 2016/17 of -3.78 per cent results in a small real increase in prices, compared to an X factor of 2.23 per cent in our June submission (see Table 2.1 above). This is largely due to the higher rate of return in our revised proposal.

While the AER's draft decision involves an average price reduction in 2016/17, whereas our revised proposal involves an increase, the AER's draft decision is not in consumers' long term interests. As noted above, achieving the NGO requires sustainable prices and the maintenance or enhancement of quality, safety, reliability and security of supply over the long term. Short term price reductions that cannot be sustained may result in outcomes that are contrary to consumers' long term interests. We consider that the price path adopted by the AER is not sustainable and would result in outcomes contrary to the NGO.

In chapter 10 *Revenue requirement and price path* we set out our price path and estimated customer network bill impacts. In chapter 11 *Reference tariff setting* we explain the structure and basis for our revised initial tariff schedule. In developing our revised initial tariff schedule we have continued to apply the principles that we applied in the June 2015 submission.

[32] ActewAGL Distribution 2015, *Access arrangement information, Overview*, June, p. 7

2.6.1 Our revised proposal promotes the NGO to the greatest degree

In contrast to the AER’s draft decision, our revised access arrangement proposal will promote consumers’ long term interests with respect to quality, safety, reliability and security of supply of natural gas, while at the same time serving the long term interests of consumers with respect to price. Our revised proposal is based on the most reasonable assumptions about the future of our gas network. Each element of the revised proposal is in accordance with the principles and objectives in the NGL and the Rules – including the revenue and pricing principles, the ARORO and the overarching NGO. It follows that our revised proposal is to be preferred to the draft decision in contributing to the achievement of the NGO.

Table 2.2 provides a summary of aspects of the AER's draft decision that are deleterious to the achievement of the NGO and why we consider our revised proposal is preferable to the draft decision in terms of promoting the NGO. The table does not constitute a complete list of aspects of the AER's draft decision that are not NGO preferable. The table shows only those elements where our revised proposal differs significantly from the AER’s draft decision. There are other elements of the AER's draft decision which we do not accept and which are not NGO preferable. Those elements are described in the relevant chapters of our revised proposal.

Table 2.2 Consumer benefits and the NGO – draft decision versus revised proposal

Draft decision	Revised proposal	Consumer benefits and the NGO
Element of draft decision/proposal - Rate of return		
The AER has rejected our proposed WACC of 7.15% and replaced it with a WACC of 6.09%.	We have revised our proposal to reflect the latest relevant market parameters and to ensure that it achieves the ARORO and the NGO to the greatest degree.	The AER's draft decision on return on equity fails to reflect returns required by equity investors to invest in a benchmark efficient entity facing a similar degree of risk as that which applies to AAD in respect of the provision of reference services. The AER's estimate of the return on equity is too low and will result in under-compensation for investment now, and a negative signal for future compensation for investment, which can in turn be expected to deter efficient investment in our business. It is well-recognised in economic theory that investment below the efficient level detrimentally affects a service provider's ability to achieve efficiency improvements in the future; that is, it compromises productive efficiency outcomes in the long term. As such, the AER's decision on the return on equity will compromise the achievement of efficiency in the long term interests of consumers with which the NGO is concerned. The AER's draft decision on the return on debt fails to provide a reasonable opportunity to recover at least the efficient debt financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to us in respect of the provision of reference services. The AER’s approach to transitioning to the trailing average estimation method will lead to a return on debt allowance for the 2016–21 access arrangement period that is below the efficient financing costs of a benchmark efficient entity for that period. As a result, the return on debt is less than what is required to promote efficient investment in, and efficient operation and use of, electricity services in the long term interests of consumers

Draft decision	Revised proposal	Consumer benefits and the NGO
		In contrast, our proposal will provide AAD with a return sufficient to access necessary funds to make efficient investments in the network, thus serving the long term interests of consumers.
Element of draft decision/proposal - Forecast capex		
The draft decision capex allowance is 38.9% below our proposal.	We have revised our proposal to ensure that it is based on the best available information and forecasts of the capex drivers. This includes a more granular forecast for medium density market expansion and retiming of the two distinct capacity development projects in the Molonglo region based on an updated dwelling forecast.	The AER's draft decision on forecast capex fails to provide us with a reasonable opportunity to recover our efficient costs incurred in providing reference services. The AER's decision to reject our forecast capex discloses a focus by the AER on short term price reductions at the expense of long term productive and allocative efficiency (encompassing the quality, safety, reliability and security dimensions of supply), and thus, the dynamic efficiency that the NGO directs should be given the balance of emphasis. Each component of our revised capex forecast is in the long term interests of consumers, including those not accepted by the AER such as: • An adequate market expansion capex which is required to ensure we are able to continue to connect new customers. Connecting new customers shares fixed costs across a greater number of consumers and is therefore in their long term interest. • The Molonglo Primary project which is required to ensure that if a severe winter occurs in 2021 our consumers do not experience either restricted or a loss of supply. Maintaining the integrity of supply to our consumers, who live in the coldest capital city in Australia, when they rely on and value gas the most, is in their long term interest. Our proposal will enable AAD to recover the efficient costs of investing in the network and connecting new customers, and ensure that customers have access to a reliable and safe gas supply, thus serving the long term interests of consumers.
Element of draft decision/proposal - Forecast opex		
The draft decision opex allowance is 8.3% below our proposal. The AER has rejected several step changes and rejected our proposals for productivity growth and output growth.	We have revised our proposal to address matters arising from the draft decision and our revised position on the efficiency carryover amount calculation. We have also updated our proposed step changes, including two additional required step changes.	The AER's draft decision on forecast opex fails to provide us with a reasonable opportunity to recover our efficient costs incurred in providing reference services. The AER's decision to reject our forecast opex further discloses a focus by the AER on short term price reductions at the expense of long term productive and allocative efficiency (encompassing the quality, safety, reliability and security dimensions of supply), and thus, the dynamic efficiency that the NGO directs should be given the balance of emphasis. In contrast to the AER's draft decision, our revised proposal will benefit consumers and promote the NGO by providing AAD with an opportunity to recover the efficient costs of managing and maintaining the network and providing safe and reliable services. It also allows for the ECM to operate correctly ensuring consumers share efficiency gains or losses in the long term.
Element of draft decision/proposal - Forecast demand and connections		

Draft decision	Revised proposal	Consumer benefits and the NGO
The AER has rejected our residential connections forecast and adopted a significantly lower forecast.	We have revised our forecasts for connections for residential medium density and high rise dwellings to ensure that they are based on the most reasonable approach and the best available information on the circumstances and characteristics of our network and our customers.	The AER's draft decision to reject our residential connections forecast and adopt a significantly lower forecast fails to provide a reasonable basis for forecasting our capital expenditure requirements and therefore negatively impacts our ability to recover efficient costs required to meet or manage the expected demand for reference services over the 2016-21 access arrangement period. In addition, it is in consumers interests to have the best possible demand forecasts as they ensure that consumers pay no more or less than necessary for our services. In contrast, our revised proposal means that we will be provided with sufficient revenue to meet growth in demand and customer connections over the 2016-21 access arrangement period.
Element of draft decision/proposal - Efficiency carryover amount		
The AER has rejected our proposed carryover amount of $11 million and replaced it with an amount of $1.4 million	While we have accepted the AER’s position that a continuous incentive should apply, we have also corrected an error in the AER’s treatment of non-recurrent costs (in the opex base year).	The AER's calculation of the efficiency carryover amount does not correctly recognise the relationship between the carryover amount and the opex allowance, resulting in a double penalty for AAD. In contrast, our revised proposal provides correct and consistent incentives for opex efficiencies and an appropriate sharing of benefits with customers.
Element of draft decision/proposal - Revenue requirement and price path		
The AER’s draft decision revenue allowance is 21 per cent below our proposal.	Our revised revenue and price path are based on building blocks that have been developed in accordance with the relevant objectives and principles in the Rules and the NGL.	The AER’s draft decision on revenue and price path will not provide us with sustainable revenues that are sufficient to ensure the quality, safety, reliability and security of supply of natural gas in the long term interests of consumers. As such the AER's draft decision on revenue and price path does not promote the NGO. In contrast, our revised proposal would allow us to continue to connect new customers and deliver safe and reliable services to our customers.

We observe the following elements of our revised proposal render the outcome conservative, in that they tend towards under-compensation of our business for efficient costs:

- we have not included an allowance for a new issue premium in estimating return on debt. In light of the evidence of a positive and significant new issue premium, making no allowance for this premium is highly conservative, in the sense that it is likely to lead to under-estimation of the efficient financing costs of a benchmark efficient entity;
- in line with the AER's draft decision, we have revised our proposal in respect of debt raising costs to include only debt raising transaction costs. That is, we have not included liquidity costs and three month ahead financing costs in our revised proposal;
- our forecast of inflation in the 2016-21 access arrangement period is conservative;

- we have not included a real price escalator to reflect the expected increase in prices we will face in purchasing materials, such as steel. The consequence of this is that our forecast capex forecast is a conservative estimate of the cost inputs required to maintain the safety and integrity of services we provide.

As set out in section 2.3.1 above and summarized in Table 2.1 above, as compared to our revised proposal, the AER's draft decision in respect of several building blocks will have a significant adverse impact on our efficient required revenue for the 2016-21 access arrangement period. As noted above, the AER's forecasts will result in a revenue allowance for the 2016-21 access arrangement period which is 22 per cent below our proposal.

A regulatory decision that sets revenue at materially less than the level otherwise determined by a proper application of the building block methodology set out in the Rules will fail to ensure the quality, safety, reliability and security of supply of natural gas services as required by the NGO. It is well-recognised in economic theory that if a service provider is undercompensated relative to efficient costs, this will affect the service provider's ability and incentive to undertake efficient investment in, or the efficient operation and use of electricity services, contrary to the long term interests of consumers.

Since our revised proposal corrects the above aspects of the AER's draft decision and ensures that we are provided with a reasonable opportunity to recover our efficient costs, an effective incentive to promote economic efficiency, and a return commensurate with the regulatory and commercial risks involved in providing reference services, considered collectively, a decision to accept our revised proposal would result in a decision that is preferable in respect of contributing to the achievement of the NGO and one that is materially preferable to the AER's draft decision.

In forming this conclusion, we have considered the interrelationships between the constituent components of the AER's decision and how such interrelationships have been taken into account by the AER. We observe that while the AER identifies some relevant interrelationships in its draft decision, it has not given full and proper consideration to all the relevant interrelationships. Our assessment of the interrelationships between components of the draft decision is provided in appendix 2.02 to this *Overview*.

A checklist of our responses to each of the AER’s required revisions is provided in appendix 2.01 to this *Overview*. Details on the basis for responses to the draft decision and our revisions to the access arrangement proposal are provided in the following chapters.

3 Services covered by the access arrangement

The *Services policy* in section 2 of the 2016-21 access arrangement describes the pipeline services offered, which comprise reference services and non-reference services.

A reference service is a service which is likely to be sought by a significant part of the market. It is governed by a standard set of terms and conditions and a reference tariff schedule, both of which are set out in the access arrangement.

A non-reference service is negotiated on a case-by-case basis with reference to the relevant access arrangement schedules including the reference tariff schedule.

In the access arrangement proposal submitted to the AER in June 2015 ActewAGL Distribution proposed to:

- consolidate the seven reference services in the 2010-15 access arrangement into a single reference service—the haulage reference service; and,
- continue to offer two non-reference services—the interconnection of embedded network service and negotiated services.

3.1 AER's draft decision

In the draft decision the AER has:

- accepted our proposal to offer a single haulage reference service; and
- accepted our proposal to continue to offer two non-reference services – the interconnection of embedded network service and negotiated services.

The AER has noted that while it has not separated ancillary services from the singular haulage reference service, it may review its draft decision after seeking stakeholder feedback and further information from ActewAGL Distribution.[33]

3.2 ActewAGL Distribution's response

In accordance with the draft decision, we have not made any revisions to the services specified in the access arrangement proposal.

In relation to ancillary services, the AER has not specified the further information that it seeks from ActewAGL Distribution. However, we offer the following comments.

Aggregation of services does not reduce the cost reflectivity of ancillary services nor mean double recovery of the costs of providing these services

In the draft decision the AER says:[34]

[33] AER 2015, *Attachment 1 – Services covered by the access arrangement, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 1-9

"As the ancillary reference services are customer requested services, the associated costs and revenues are difficult to forecast with accuracy. Therefore combining these costs and revenues together with the other haulage reference services will reduce the cost reflectivity of the ancillary reference services and potentially lead to double recovery of the costs."

Our proposed ancillary charges seek to recover the cost of user-initiated ancillary activities to ensure other customers are not required to inefficiently cross-subsidise the costs of these user-initiated activities. The user-requested activities, and the ancillary charges, are set out in ActewAGL Distribution's reference tariff schedule (see schedule 3 of the revised access arrangement).

To the extent the AER is concerned that the aggregation of ancillary services into the haulage reference services could lead to the "double recovery of the costs', we note that the regulatory framework effectively limits ActewAGL Distribution's aggregate revenue (for a given level of demand). Each incremental dollar recovered through ancillary charges is a dollar that is not recovered through other services in the haulage reference service, such as haulage of gas or provision of metering services. We note and agree with the AER's comment in relation to metering services and note that it relates equally to all of our ancillary services:[35]

"We also note the aggregation of the service does not lead to aggregation of the underlying costs. Therefore we are satisfied there is no double recovery of the costs for these services."

The AER has approved a single haulage reference service, incorporating ancillary services, for Jemena Gas Networks.

One of our guiding principles in developing our access arrangement proposal was harmonization with other approved access arrangements, and in particular the access arrangement for JGN's NSW gas network.

We engaged with consumers and retailers on the benefits of a simplified and harmonized services structure, and they supported this.

The AER has approved a single reference service, incorporating ancillary services, for JGN.

Departing from the draft decision (and the JGN final decision) and separating ancillary services would involve costs, as it would unnecessarily complicate our services and charges, but would produce no benefits.

---

[34] AER 2015, *Attachment 1 – Services covered by the access arrangement, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 1-9

[35] AER 2015, *Attachment 1 – Services covered by the access arrangement, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 1-9

4 Capital base

4.1 Draft decision

The draft decision did not approve ActewAGL Distribution's proposed capital base as at 1 July 2015 of $339.0 ($nominal) because of an adjustment it made to the IT systems asset class. The AER determined an opening capital base of $338.6 million ($nominal) as at 1 July 2015, 0.1 per cent less than that proposed by ActewAGL.

The draft decision also did not approve ActewAGL Distributions' proposed roll forward of our projected capital base to 30 June 2021. This is because the AER did not approve several inputs to the roll forward calculation. The AER determined a projected closing capital base of $419.7 million ($nominal) as at 30 June 2021, 10.2 per cent less than that proposed by ActewAGL.

4.2 ActewAGL Distribution's response and revisions

Table 4.1 summarises ActewAGL Distribution's response to the AER's draft decision on key issues.

Table 4.1 Response to draft decision on key issues

Initial proposal	Draft decision	Response to draft decision
Proposed exclusion of over-depreciated IT systems capital base value from the opening capital base	Reject	Accept draft decision
Proposed to use forecast depreciation to establish the opening capital base as at 1 July 2021	Accept	Accept draft decision
Proposed forecast capex of $116.2 million ($nominal) over 2015-16 to 2020-21	Reject	See capex chapter for response and revised proposal
No depreciation allowance for 2015-16	Reject	Accept draft decision
Real straight-line depreciation method to calculated the regulatory depreciation allowance	Accept	Accept draft decision
Proposed weighted average method to calculated remaining asset lives as at 1 July 2015	Accept	Accept draft decision
No separate land and easement asset class proposed	Reject	Accept draft decision

4.3 Updated values

The projections of the capital base in ActewAGL Distribution's revised proposal reflect the following updates:

- actual capex and capital contributions for 2014/15;

- updated values of the CPI for 2014/15 (actual) and 2015/16 to 2020/21 (forecast);
- updates to the forecast capex proposal as described in the capex chapter; and
- adjusting the allocation of assets between the 'contract meters' and 'tariff meters' asset class.[36]

4.4 Revised proposal

Table 4.2 and Table 4.3 set out the proposed capital base roll forward for the period 1 July 2010 to 30 June 2015, and 1 July 2015 to 30 June 2021 respectively.

Table 4.2 Roll forward of capital base from 1 July 2010 to 30 June 2015 ($million, nominal)

	2010/11	2011/6	2012/13	2013/14	2014/15
Opening balance (1 July)	278.1	288.59	302.2	313.8	326.9
Net capex	12.0	15.0	18.7	18.6	24.3
Indexation of capital base	7.9	9.8	5.3	7.7	8.1
Depreciation of capital base	-9.4	-11.2	-12.5	-13.2	-13.7
Adjustment for 2009-10 capex	0	0	0	0	-7.5
Closing capital base (30 June)	**288.6**	**302.2**	**313.8**	**326.9**	**338.1**

Table 4.3 Roll forward of capital base from 1 July 2015 to 30 June 2021 ($million, nominal)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Opening balance (1 July)	338.1	365.5	380.1	393.8	408.2	423.0
Net capex	31.8	20.1	19.9	21.4	22.7	18.5
Indexation of capital base	7.4	8.0	8.3	8.6	8.9	9.3
Depreciation of capital base	-11.8	-13.4	-14.5	-15.6	-16.9	-18.0
Closing capital base (30 June)	**365.5**	**380.1**	**393.8**	**408.2**	**423.0**	**432.7**

[36] Both asset classes have a standard life of 15 years and the revised allocation was to correct a previous oversight in the allocation between asset classes. There has been no change in the total combined carrying value of these two asset classes.

5 Rate of return, gamma and inflation

In this Chapter we explain why the draft decision does not provide for an overall rate of return that is consistent with the NGO.

A summary of the AER's draft decision is provided in Section 5.1, followed by an overview of ActewAGL Distribution's response and revisions (Section 5.2):

- Section 5.2.1 sets out our understanding of the allowed rate of return objective.
- Section 5.2.2 summarises ActewAGL Distribution's response and revisions concerning the rate of return to apply in the 2015/16 year (in performing the true-up for the interval of delay in accordance with Rule 92(3) of the NGR) and the 2016-21 regulatory period, including in relation to the key parameters—return on debt, return on equity, gamma and inflation—and the interrelationships between them. A more detailed articulation of ActewAGL Distribution's response and revisions concerning the rate of return to apply in the 2015/16 year and the 2016-21 regulatory period is included as Appendix 5.01 and supported by expert reports (Appendices 5.02-5.10).
- The AER's decision on debt and equity raising cost and ActewAGL Distribution's response is covered in Section 5.2.3.

5.1 AER's draft decision

The AER has not accepted ActewAGL Distribution's proposed rate of return for the 2016-21 regulatory period (7.15 per cent nominal vanilla weighted average cost of capital) and has instead determined an indicative 6.09 per cent rate of return for the 2015/16 year. The AER's indicative rate of return is based on a placeholder averaging period for the return on equity risk free rate of the 20 business days commencing 4 August 2015 and the return on debt averaging period proposed by ActewAGL Distribution and accepted by the AER for the 2015/16 regulatory year of the 15 business days commencing 4 June 2015.

The AER contemplates that this rate of return, updated in the final decision for ActewAGL Distribution's actual return on equity risk free rate averaging period, will apply to ActewAGL Distribution for the 2015/16 year, for the purposes of the true-up for the interval of delay in accordance with Rule 92(3) of the NGR. The return on debt component will be updated annually thereafter to partially reflect the prevailing debt market conditions in ActewAGL Distribution's averaging period for each year of the 2016-21 regulatory period.

In determining an (indicative) allowed rate of return of 6.09 per cent, the AER:

- rejected ActewAGL Distribution's approach of taking an average from four models (Sharpe Lintner Capital Asset Pricing Model (SLCAPM), Fama French Three Factor Model (FFM), Black CAPM and dividend discount model) to estimate the return on equity;

- used the SLCAPM alone to estimate the return on equity resulting in a return on equity of 7.30 per cent (against 9.87 per cent proposed by ActewAGL Distribution);
- adopted the 2015/16 year, rather than the 2016/17 year, as the first year of the AER's transition to the trailing average portfolio approach for estimation of the return on debt;
- estimated an on-the-day rate (that is, based on prevailing market conditions) for the 2015/16 year of 5.29 per cent using the average period proposed by ActewAGL Distribution for the 2015/16 year (being the 15 business days commencing 4 June 2015, i.e. 4 June to 25 June 2015), and proposed to gradually transition this rate into a trailing average approach over 10 years by updating 10 per cent of the return on debt each year to reflect prevailing market conditions in the debt averaging period for that year consistent with the AER's Rate of Return Guideline;
- rejected ActewAGL Distribution's proposed credit rating (BBB) and ActewAGL Distribution's proposed return on debt methodology — including the method for annually updating the return on debt and nominating the averaging period used to apply it;
- accepted ActewAGL Distribution's proposed terms for the returns on debt and equity of 10 years, as well as a gearing level of 60 per cent; and
- rejected the value of imputation credits as 0.25 that was proposed by ActewAGL Distribution and supported by the evidence outlined in ActewAGL Distribution's proposal. The AER instead determined a value of 0.40.

The AER also:

- rejected ActewAGL Distribution's 0.243 per cent estimate for debt raising costs and instead applied 0.092 percent; and
- updated ActewAGL Distribution's proposed inflation estimate to reflect the latest forecasts from the Reserve Bank of Australia (RBA).

5.2 ActewAGL Distribution's response and revisions

This section provides a summary of the key aspects of Appendix 5.01 to ActewAGL Distribution's response to the draft decision. Appendix 5.01 addresses the allowed rate of return, the value of imputation credits (gamma) and the method for forecasting inflation for the 2015-21 period. These topics are addressed together in Appendix 5.01 because they each impact on the overall return to investors. Specifically:

- under the National Gas Rules (**NGR**), the allowed rate of return is the post-tax return allowed to investors, calculated as a weighted average of the return on equity and return on debt;[37]

[37] NGR, rule 87(4).

- gamma represents the value of imputation credits to investors associated with the payment of company tax. This value effectively forms part of the overall return to equity investors;
- forecast inflation is used to adjust the cash flows to maintain a real rate of return framework.[38] It thus has an important interrelationship with the rate of return, and impacts on the overall return to investors—it is akin to capital gains earned on an investment. If inflation is not correctly forecasted, the adjustment to cashflows may be too large (or too small) and thus investors may receive an overall return that is too low (or too high).

In order to promote the National Gas Objective (**NGO**), the overall return to investors must be sufficient to promote efficient investment in, and efficient operation and use of, gas services for the long term interests of consumers. Critical to the promotion of efficient investment is that businesses be provided with a reasonable opportunity to recover efficient costs (i.e. the costs that would be incurred by an efficient business in a workably competitive market). This means that:

- the return on debt allowance must be such as to provide a reasonable opportunity to recover at least the efficient debt financing costs of a benchmark efficient entity (**BEE**) with a similar degree of risk as that which applies to ActewAGL Distribution's in respect of the provision of reference services;
- the return on equity allowance must reflect returns required by equity investors to invest in businesses facing a similar degree of risk;
- gamma must reflect the value that equity-holders place on imputation credits (not simply their face value or utilisation rate). If the value of imputation credits is over-estimated, the overall return to equity-holders will be less than what is required to promote efficient investment in, and efficient operation and use of, gas services for the long term interests of consumers; and
- the inflation forecast must reflect market expectations of inflation over the 2015-21 period.

The draft decision does not provide for an overall return for the 2015-21 period that is consistent with the NGO. For reasons set out in this section below and in Appendix 5.01:

- the allowed rate of return is not commensurate with the efficient financing costs of a BEE with a similar degree of risk as that which applies to ActewAGL Distribution in respect of the provision of reference services;

[38] While the PTRM is a nominal model in that it has nominal inputs including for the rate of return, the PTRM is properly understood as embodying a real rate of return framework in that it derives a real revenue path for the regulatory period, expressed in terms of the real X factor for each regulatory year of the regulatory period, that includes compensation for a real rate of return (effectively derived by the PTRM by taking a nominal input for the cost of debt and equity and deducting forecast inflation).

- the value of imputation credits is over-estimated, meaning that the reduction to the overall return to account for imputation credits is too large; and
- the AER's forecast of inflation is also over-estimated, meaning that the reduction to the overall return to account for expected indexation of the regulatory asset base is too large and otherwise does not reflect current market expectations.

This Appendix 5.01 of our submission explains our specific concerns with the preliminary decision in relation to the rate of return, value of imputation credits and forecast inflation.

As explained below, in some areas (such as the benchmark gearing level and term of debt) we agree with the AER's position in the preliminary decision. To the extent that the AER proposes to change its position in any of these areas in its final decision, ActewAGL Distribution would need to be informed of that, and provided with a reasonable opportunity to respond to any proposed change of approach.

5.2.1 Achieving the allowed rate of return objective

The allowed rate of return objective (**ARORO**) is the touchstone for estimating the allowed rate of return. The NGR require that:

- the return on equity for an access arrangement period be estimated such that it contributes to the achievement of the ARORO;[39] and
- the return on debt for a regulatory year be estimated such that it contributes to the achievement of the ARORO.[40]

The ARORO is that the rate of return for a service provider is to be commensurate with the efficient financing costs of a BEE with a similar degree of risk as that which applies to the service provider in respect of the provision of reference services.[41]

As can be seen, the ARORO has two key elements:

- first, the ARORO requires identification of the level of risk that applies to the service provider in respect of the provision of reference services; and
- secondly, the ARORO requires estimation of efficient financing costs for a BEE facing a similar degree of risk.

ActewAGL Distribution considers that the relevant level of risk is that faced by entities operating in a workably competitive market providing services similar to reference services within Australia. Therefore, in constructing comparator datasets for the purposes of estimating a rate of return that is commensurate with efficient financing costs of a BEE, these datasets should include entities that face a similar degree of risk to that faced in the provision of reference services. That is, they should not be restricted to regulated entities.

[39] NGR, rule 87(6).

[40] NGR, rule 87(8).

[41] NGR, rule 87(3).

If ActewAGL Distribution is incorrect that the relevant level of risk is that faced by entities operating in a workably competitive market providing services similar to reference services within Australia, but rather, the relevant level of risk is that of a regulated energy network business, ActewAGL Distribution submits that the reference to 'efficient financing costs' in the ARORO is to costs incurred (and therefore financing practices adopted) in a workably competitive market to finance an investment with that risk profile.

That is, regardless of what the relevant degree of risk is, once this risk benchmark is established, the assessment of efficient financing costs requires consideration of what financing practices would be engaged in by businesses operating in a workably competitive market, facing the relevant degree of risk. Such an interpretation of the term 'efficient financing costs' in the ARORO is consistent with the object of regulation itself, which is to simulate competitive market outcomes. This is because it is ultimately competition that drives efficient behaviour and is the benchmark that the NGL seeks to replicate. The 'workably competitive market' concept is described in more detail in section 1.2 of Appendix 5.01.

Many of the issues dealt with in this chapter are the subject of applications for merits review of the AER's distribution determinations for the NSW electricity distributors (Ausgrid, Endeavour Energy, Essential Energy), ActewAGL Distribution, and the NSW gas distributor (JGN) (**NSW and ACT merits reviews**). These issues include the approach taken by the AER to estimating the return on equity and the methodology to estimate the return on debt. The applications were heard in September and October 2015. Once the decision of the Tribunal has been published, ActewAGL Distribution will review the decision and consider the implications, if any, of that decision for the final decision the AER is required to make for ActewAGL Distribution in respect of its 2016-21 access arrangement. To the extent ActewAGL Distribution considers that the decision does have implications for its proposal, ActewAGL Distribution will make any submissions to the AER on those implications as soon as practicable after the Tribunal's decision has been published and considered by ActewAGL Distribution.

5.2.2 Allowed rate of return for 2015-21 period

5.2.2.1 Return on debt

As became clear from the detailed consideration of the return on debt issue in the NSW and ACT merits reviews, the method that the AER proposes to adopt in its draft decision for estimating the return on debt will not deliver a return on debt estimate which contributes to the achievement of the ARORO and the NGO. As ActewAGL Distribution maintained in its electricity reset and the NSW and ACT merits reviews, the ARORO is concerned with the financing costs and practices that are efficient in the economic sense, that is, the financing costs incurred, and practices adopted, in a workably competitive market.

As set out in Appendix 5.01, ActewAGL Distribution submits that the debt management practice that would be expected absent regulation is the holding of a staggered portfolio of fixed rate debt, the cost of which can be estimated by the trailing average approach. Given the intent of regulation is to replicate, insofar as possible, the outcomes that would be expected in workably competitive markets, the efficient financing costs to be estimated pursuant to rule 87 of the NGR are required to be estimated using the trailing average approach and this approach should be adopted without any transition (AER Option 4).

The AER’s approach to transitioning to the trailing average estimation method will lead to a return on debt allowance for the 2015-21 period that is below the efficient financing costs of a BEE for that period. This is because:

- The AER’s approach proceeds on the incorrect premise that the efficient financing costs of a BEE are those that would be incurred under the financing practices that would have emerged under the previous regulatory approach to estimating the return on debt. The correct approach is to identify the efficient financing costs of a BEE, which are the costs that would be incurred in a workably competitive market (or, put another way, the costs that would be incurred absent regulation).
- The AER considered that the trailing average approach may be more reflective of the actual debt management approaches of non-regulated businesses and therefore, more likely to represent efficient financing practice.[42] The AER found that the efficient financing practice under the trailing average approach is to hold a staggered portfolio of fixed rate debt.[43] The efficient financing costs of a BEE are thus the costs associated with a staggered portfolio of fixed rate debt.
- Expert advice from CEG confirms that a 10 year trailing average approach would largely mimic the debt management strategy employed by unregulated infrastructure businesses.[44]
- Given that the costs associated with a staggered portfolio of fixed rate debt are best approximated by a trailing average methodology, the immediate implementation of the trailing average approach to estimating the return on debt will provide an allowance that reflects efficient financing costs. Conversely, application of a transition that results in the return on debt being different from efficient financing costs will, by definition, lead to an allowance that is not commensurate with the efficient debt financing costs of a BEE.

ActewAGL Distribution observes that, in addition to the above issues with the AER's approach, there is no basis under the NGR for applying a transition to the trailing average approach to estimating the return on debt to ActewAGL Distribution in circumstances where ActewAGL Distribution is currently, and was in and prior to the 2010-15 regulatory period, 100 per cent financed by equity.[45] As it has no debt financing, ActewAGL Distribution has not entered into debt financing arrangements by reference to the on-the-day approach to estimating the cost of

[42] AER, *Rate of Return Guideline: Explanatory Statement*, December 2013, pp.108–111

[43] AER, *Rate of Return Guideline: Explanatory Statement*, December 2013, pp.108–110

[44] CEG, *Efficiency of Staggered Debt Issuance*, February 2013, [92], [97], [101] and [102]

[45] CEG, *Debt transition consistent with the NER and NEL*, May 2014, Appendix C; CEG, *Efficient debt financing costs*, 19 January 2015, section 7.

debt and no transition to the trailing average approach to estimating the return on debt is required.

For these reasons, ActewAGL Distribution considers that the trailing average approach should be implemented immediately, with no transition.

Alternatively, even if the AER's approach of estimating efficient financing costs by reference to the financing practices that would emerge under regulation were correct, the appropriate approach would be to adopt a hybrid form of transition where only the hedged base rate component of the return on debt is subject to a transition (AER Option 3). This is because the AER has concluded that under the previous on-the-day approach to estimating the return on debt, an efficient financing practice would have been to engage in hedging of the base rate. By contrast, the AER has conceded that the debt risk premium (**DRP**) component of the return on debt cannot be (and could not have been) hedged, with the result that there is no reason for a transition to be applied to it.

If the hybrid transition is to be adopted, it would then be necessary to consider to what degree hedging would have been efficient. While the AER's reasoning assumes that the efficient level of hedging was 100 per cent, this is incorrect as a matter of fact and the evidence demonstrates that the efficient level of hedging of the base rate under an on the day approach to estimating the return on debt is significantly less than 100%.

On any view of what efficient financing costs are, the AER's transition cannot be justified. Even on the AER's view of the correct approach to estimating efficient financing costs, and assuming that the BEE hedged the base rate 100 per cent, application of the AER's transition would lead to a mismatch between efficient financing costs and the regulatory allowance on the DRP component as the DRP could not have been hedged by a BEE.

In respect of implementation issues, ActewAGL Distribution submits that the AER should:

- adopt a benchmark credit rating of BBB / BBB+, as in the draft decision;
- continue to adopt a benchmark term of 10 years;
- for the 2015/16 year, estimate a trailing average return on debt for that year for use in performing the true-up for the interval of delay by taking a simple average of:
    - the RBA curve in ActewAGL Distribution's nominated averaging period for that year (accepted by the AER in its Draft Decision) of the 15 business days commencing 4 June 2015; and
    - the prevailing return on debt for each of the preceding nine financial years, estimated as the simple average of the RBA and Bloomberg curves in an averaging period for each of those financial years of the full 12 months of the immediately preceding financial year;
- for the first regulatory year of the 2016-21 access arrangement period (2016/17), estimate a trailing average return on debt by taking a simple average of:

- the prevailing return on debt for that year estimated using the data source and extrapolation method, selected using ActewAGL Distribution's proposed method for selection of the independent data source and extrapolation method, that best fits a representative sample of bond yields over ActewAGL Distribution's nominated averaging period for 2016/17;
- the prevailing return on debt in the 2015/16 year estimated in the manner described above (that is, the RBA curve in ActewAGL Distribution's averaging period of the 15 business days commencing 4 June 2015); and
- an average of Bloomberg and RBA estimates of the prevailing return on debt for each of the prior eight years (adopting as the averaging period for each of those financial years the full 12 months of the immediately preceding financial year); and

- for all subsequent regulatory years of the 2016-21 access arrangement period, update the trailing average return on debt allowance to reflect the estimate of the prevailing return on debt in the averaging period nominated by ActewAGL Distribution for that year using its proposed data source and extrapolation technique selection method.

ActewAGL Distribution notes that its proposed method for estimating the return on debt does not make any allowance for a new issue premium. ActewAGL Distribution considers that in light of the evidence of a positive and significant new issue premium, making no allowance for this premium (as ActewAGL Distribution does) is highly conservative, in the sense that it is likely to lead to under-estimation of the efficient financing costs of a BEE.

5.2.2.2 Return on equity

The method adopted by the AER in its draft decision does not result in a return on equity that is consistent with the ARORO.

The evidence before the AER is that its estimate is too low. In particular:

- the AER’s estimate fails a number of its own cross-checks; and
- it is below all available and relevant evidence as to the return on equity required by investors.

This outcome is the result of:

- the AER relying solely on the output of a model that is known to produce biased estimates, without the AER correcting for this bias;
- the AER applying this model in a way that does not reflect market practice and which results in the return on equity simply tracking movements in the risk-free rate; and
- errors in interpretation and use of key evidence, including empirical evidence relating to the estimation of the market risk premium (**MRP**) and equity beta.

ActewAGL Distribution continues to believe that the ARORO is best achieved through an approach that properly has regard to estimates from all relevant return on equity models. In its

June 2015 proposal, ActewAGL Distribution proposed that each of the Sharpe Lintner Capital Asset Pricing Model (**SL CAPM**), the Black CAPM, the Fama French Three Factor Model (**FFM**) and Dividend Growth Model (**DGM**) be estimated, and that these estimates each be given appropriate weight in deriving a return on equity estimate.[46] ActewAGL Distribution maintains its view that this approach would best achieve the ARORO.

However, if the AER proposes to continue relying solely on the SL CAPM to estimate the return on equity, it becomes even more important that the estimates of the MRP and equity beta are calculated in a manner that has proper regard to relevant material in order to ensure that its estimate of the return on equity is consistent with the ARORO and reflects prevailing market conditions. Of particular importance are the DGM estimates for the MRP and evidence from wider datasets for the equity beta.

This response outlines an alternative approach that involves properly adjusting SL CAPM parameters to deliver a return on equity that contributes to the achievement of the ARORO and reflects prevailing market conditions. This involves:

- determining a robust 'starting point' equity beta estimate, based on a sufficiently large sample of comparable businesses;
- making a transparent and empirically based adjustment to the equity beta estimate to account for the known shortcomings of the SL CAPM, particularly low beta bias and book-to-market bias; and
- deriving the MRP in a way that gives appropriate weight to measures of the prevailing market conditions (i.e. the prevailing MRP).

This alternative approach leads to an estimate of the prevailing return on equity for the 2015-21 period of 9.89 per cent (based on a placeholder averaging period for the risk free rate of the 20 business days ending 30 September 2015).

5.2.2.3 Gearing

ActewAGL Distribution maintains its proposed gearing ratio of 60 per cent, accepted by the AER in the draft decision, for the reasons set out in ActewAGL Distribution's proposal, and the draft decision.

5.2.2.4 Gamma

The AER's estimate of gamma does not reflect the value of imputation credits to investors. The AER has over-estimated gamma, meaning that the reduction to the overall return to account for imputation credits is too large.

The AER's approach to estimating gamma is premised on an incorrect interpretation of the NGR. The AER seeks to estimate gamma on a "pre-personal-costs" basis, which is equivalent to

[46] ActewAGL Distribution 2015, *Access Arrangement information, Appendix 8.02, Return on equity, detailed proposal,* June, p.1

estimating gamma as the *rate of utilisation* (or assumed utilisation) of imputation credits, rather than their *value* to investors.

As a result, the AER has erred in its use of evidence in relation to gamma:

- the AER uses equity ownership rates as direct evidence of the value of distributed credits (theta), when in fact equity ownership rates are no more than an upper bound (or maximum) for this value;
- the AER also uses redemption rates as direct evidence of the value of distributed credits (theta), when in fact redemption rates are no more than an upper bound (or maximum) for this value; and
- the AER has erred in concluding that market value studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the task of measuring theta. Market value studies are direct evidence of the value of imputation credits to investors.

Further, the AER has made errors in its interpretation and use of key evidence, including by proceeding on the incorrect footing that estimates of theta based on data for listed companies can only be combined with estimates of the “listed equity” distribution rate.

On a proper interpretation of the empirical evidence:

- both tax statistics and equity ownership data indicate that theta can be no higher than 0.45, and that therefore the upper bound for gamma is 0.3;
- the best evidence as to the value of imputation credits – from SFG’s updated dividend drop-off study – indicates that theta is approximately 0.35 and that gamma is 0.25.

Even on the AER’s interpretation of the NGR, its gamma estimate cannot be supported. The evidence demonstrates that if gamma is estimated on a “*pre-personal-costs*” basis, the best estimate is approximately 0.3.

5.2.2.5 Forecast inflation

Recent market evidence demonstrates that the AER’s forecasting method is currently over-estimating inflation.

The consequence of this is that:

- the inflation forecast used to make adjustments to cash flows is inconsistent with the forecast of inflation implied in the nominal rate of return; and
- the downward adjustment to depreciation cash flows will be too large, thus artificially depressing the overall return to investors.

Accordingly, while our June 2015 proposal was that inflation be calculated using the AER's approach, ActewAGL Distribution now proposes that an alternative forecasting method, based on market data, be adopted to estimate inflation for the 2015-21 period. This alternative method will ensure consistency between the inflation forecast used to make adjustments to cash flows and the forecast of inflation implied in the nominal rate of return.

5.2.2.6 Interrelationships

There is a well-recognised interrelationship between the return on equity and the value of imputation credits – since the MRP needs to be grossed up for the value of imputation credits, a higher theta estimate implies a higher required return on equity.

- This interrelationship is accounted for in this submission and the supporting evidence.
- If the AER were to reduce its estimate of theta to 0.35, while maintaining its current approach to estimating the MRP, no adjustment to the AER's MRP estimate would be necessary. This is because the top of the AER's range of estimates of the historical average MRP (used by the AER as its MRP point estimate) would remain at 6.5%.[47]

There is also an interrelationship between the method for forecasting inflation and the amount that is deducted from forecast depreciation for indexation of the RAB, and between the allowed rate of return and the method for forecasting inflation. Due to these interrelationships, the forecast of inflation needs to be accurate (i.e. as close as possible to actual inflation, which is used to roll forward the RAB at the end of the regulatory period) and consistent with the implied forecast of inflation in the nominal rate of return. The best way to do this is to rely on the same dataset (i.e. market prices of securities) to estimate both.

ActewAGL Distribution does not accept that there is an interrelationship between the method for transitioning to the trailing average approach to estimating the return on debt and the equity beta. As noted by Chairmont, the required return on equity is not affected by the DRP mismatch risk as it is a diversifiable specific risk rather than a component of market systematic risk.[48] Therefore any change in the AER's approach to estimation of the return on debt (including any change to the transition method) will not affect the equity beta.

Finally, ActewAGL Distribution considers that the return on equity and return on debt need to be estimated on the basis of a consistent approach to the ARORO. As explained in Appendix 5.01, our proposed approaches to estimating the return on equity, return on debt and the overall rate of return, as set out in sections 1, 2 and 3 of Appendix 5.01, are consistent with the approach to the ARORO described in section 5.2.1 above.

5.2.3 Debt and equity raising costs

5.2.3.1 Debt raising costs

The AER has accepted ActewAGL Distribution's method for determining debt raising transaction costs.

ActewAGL Distribution had also proposed to apply two other forms of debt raising costs:

[47] For reasons set out in section 3.4 of Appendix 5.01, ActewAGL Distribution does not agree with the AER's approach to estimating the MRP. However we note that if the AER were to maintain the same approach to estimating the MRP while lowering its estimate of theta, its estimate of the MRP would not need to change.

[48] Chairmont, *Financing Practices Under Regulation: Past and Transitional*, 13 October 2015, p.40

- Liquidity costs—these are costs to establish and maintain bank facilities to meet Standard and Poor's (S&P's) liquidity requirements to maintain an investment grade credit rating.
- Three month ahead financing—these are costs to compensate S&P's requirement that businesses refinance their debt 3 months ahead of the maturity date of their existing debt.

The AER has rejected both of these additional costs. In rejecting these costs the AER has referenced the April 2015 Transgrid decision wherein the AER stated:

> *…. if costs are adequately compensated in one component of our decision, we must take that into account when considering the interrelated components of our decision. Otherwise, the overall decision may over- or under- compensate the service provider.*[49]

Moreover, within the Transgrid decision, the AER specifically stated:

> *We reached this decision primarily because the PTRM's timing assumptions already provide adequate compensation for the timing of revenue compared to expenses (liquidity related costs), to the extent that these cost streams are necessary.*[50]

The AER premised its Transgrid decision and, in turn, its draft decision in respect of our proposal, along the lines above and noting:

- the proponents had not engaged with the relevant Rule's interrelationship provisions;
- a belief that debt raising expenses were being 'double counted' as there were already being compensated for both through the opex forecast and the PTRM's timing assumptions; and
- Incenta had previously authored a report in which it was recommended that working capital costs did not have to be separately compensated in the regulatory decision due to the favourable timing assumptions in the PTRM. The AER goes on to note that '…. these working capital costs are very similar to the 'other' debt raising costs proposed by TransGrid. Both are costs associated with liquidity.'[51]

The AER's discretion in setting opex under the Rules is limited (clause 91(2)) and the AER's determination of opex, as per clause 91(1)), must reflect that which:

> *…. 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.*

[49] AER, 2015, *Final decision TransGrid transmission determination–Attachment 3 rate of return*, April 2015, pp. 3-545.

[50] AER, 2015, *Final decision TransGrid transmission determination–Attachment 3 rate of return*, April 2015, pp. 3-544.

[51] AER, 2015, *Final decision TransGrid transmission determination–Attachment 3 rate of return*, April 2015, pp. 3-546.

When the analysis of the interrelated components of the AER's decision is extended beyond the narrow confines of the PTRM's timing assumptions it becomes clear that, by not allowing the entire 24.3 bppa allowance sought by ActewAGL Distribution for the 2015-21 period, the AER is not:

- basing its assessment on the action of a prudent service provider acting efficiently and in accordance with accepted good industry practice (and more specifically good debt raising practices); nor,
- providing ActewAGL Distribution with a reasonable opportunity to recover its efficient operating costs as required under section 24 of the National Gas Law.

ActewAGL Distribution revises the appropriate estimate of debt raising costs to 9.2 bppa for the 2015-21 period, equivalent to only estimating debt raising transaction costs. However, it maintains that this renders its revised proposal conservative in that it will tend to under-compensate ActewAGL Distribution for its efficient debt raising costs and thus opex in the 2015-21 period. This revised estimate is conservative because:

- *ActewAGL Distribution has assumed a moderate estimate of forecast inflation*—As noted in Section 5.2.2.5 and Appendix 5.01, ActewAGL Distribution is proposing the use of a market-based method for forecasting inflation for the 2015-21 period. In advancing the use of this method, ActewAGL has adopted a 10 year break even estimate of 2.19 per cent even though there are robust grounds for assuming a lower inflation estimate, for example, using CEG's implementation of the Fisher equation method, which places 60 per cent weight on a 5 year inflation forecast and 40 per cent weight on a 10 year inflation forecast, and substitutes actual inflation into the forecast used for indexation of the debt-financed portion of the RAB, where actual observations are available.
- *The AER has not quantified the compensation provided through the PTRM's cashflow timing assumptions*—The AER points to the PTRM's timing assumptions providing compensation for 'working capital' requirements. However, while 'working capital' requirements relate to liquidity, and part of the costs in question here relates to 'liquidity', it does not follow that the allowance ActewAGL Distribution sought was a working capital allowance. ActewAGL Distribution requires a working capital allowance regardless of whether it was a bond issuer or not. This is because working capital facilities are used to manage cashflow timing mismatches arising out of the normal operating cycle. The liquidity facility described on our June proposal was designed to meet the requirements of S&P and it would need to be in addition to any working capital facilities held by ActewAGL Distribution. The arguments advanced by the AER are largely academic, as it has not sought to quantify the alleged compensation provided through the PTRM's cashflow timing assumptions (which ActewAGL Distribution believes would require a comparison of assumed cashflow timing assumptions and its actual cashflow timing). Accordingly, there is no basis for the AER's assertion that the purported generosity in the PTRM's cashflow timing assumptions would be adequate to compensate ActewAGL Distribution for its liquidity and three month ahead financing costs.

5.2.3.2 Equity raising costs

Equity raising costs are costs required to be paid by an entity when it raises equity, either internally (via reinvested dividends) or externally from new or existing shareholders. New equity is often needed to maintain a given capital structure (i.e. 60 per cent gearing) and credit rating, especially when capital expenditure grows faster than revenues. The costs of raising new equity include legal services and investment banking fees.

Given our forecast cost of service for the 2015-21 period, the forecast value of equity raising costs was immaterial. Hence, we did not include any equity raising costs in our proposal, and this was accepted by the AER's in its draft decision.

In our revised proposal, the calculation of equity raising costs over the 2015-21 period is set out in ActewAGL Distribution's PTRM (Appendix 10.01). Although we continue to estimate zero equity raising costs for the 2015-21 period at this stage, we propose retaining the calculation within the PTRM and updating it for any changes in forecast cash flows or RAB in the AER's final decision.

We advance the following methodology and input assumptions for estimating equity raising costs for a benchmark efficient entity with the same characteristics as ActewAGL Distribution, including:

- forecast RAB and cash flows over the 2015-21 period;
- leverage of 60 per cent; and
- dividend payout ratio of 70 per cent, consistent with ActewAGL Distribution's proposed value of imputation credits.

Consistent with recent AER decisions, we propose benchmark efficient equity raising costs of:

- *one per cent* on equity raised internally (through dividend reinvestment)—assuming a dividend payout of 70 per cent and dividend reinvestment take-up rate of 30 per cent; and
- *three per cent* on equity raised externally.

We also propose applying these percentages to ActewAGL Distribution's forecast RAB (and assuming 60 per cent gearing) using the AER's most recent method, and capitalising any equity raising costs to the RAB at the start of the 2021-26 regulatory period.

6 Capital expenditure

ActewAGL Distribution's capital program is focused on ensuring the continued safe, reliable, environmentally sustainable and efficient delivery of gas in the long term interests of our gas consumers.

In June 2015, ActewAGL Distribution forecast capex of $115.65 million ($2015/16) for the 2016-21 access arrangement period. This expenditure is required to continue to prudently and efficiently connect new customers, provide infrastructure to ensure reliability for existing customers, renew infrastructure to meet regulatory requirements, and ensure the integrity and safety of the gas network.

The AER did not accept our capex forecast in its draft decision, instead determining an alternative forecast of $76.8 million (2015/16). The lower capex forecast was primarily due to lower alternative estimates for:

- market expansion—due to a lower connection forecast for medium-density connections; and
- capacity development—the AER considered that two distinct capacity development projects in Molonglo (a primary and secondary to address separate constraints) were not yet required.

We have considered the AER's draft decision. This chapter provides a detailed response to the AER's concerns. In particular, we have developed a more granular capex forecast for medium-density connections, and updated the timings for our capacity development projects based on an updated new dwelling forecast. We have also accepted elements of the AER's draft decision, such as lower costs for the Watson Custody Transfer Station (CTS) pressure limiting station.

A summary of our revised capex forecast is provided in Table 6.1.

Table 6.1 Revised proposal forecast capex ($millions, 2015/16, escalated, including CMF, including overheads)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Market expansion	8.56	9.10	9.28	9.33	9.19	45.47
Capacity development	3.01	1.28	2.13	6.99	2.64	16.04
Stay in business	8.00	8.83	8.62	4.72	5.09	35.27
Non-system capex	0.21	0.11	0.22	0.00	0.00	0.54
Sub total	**19.78**	**19.32**	**20.26**	**21.05**	**16.92**	**97.32**
Capital contributions	0.74	0.83	0.83	0.84	0.84	4.08
Total	**19.04**	**18.49**	**19.43**	**20.21**	**16.07**	**93.24**

We consider that our revised forecast has been arrived at on a reasonable basis and is the best forecast possible in the circumstances, as required by Rule 74 of the NGR. Further, we consider that this revised forecast is materially preferable to the alternative forecast developed by the

AER. For instance, our forecast will ensure that the Molonglo Primary will be in place by 2021 to ensure that our consumers—who mainly live in the coldest capital city in Australia—do not experience either restricted or loss of supply in a severe winter (when they rely on, and value, their gas service the most).

In this chapter we provide further detail our initial proposal, the AER's draft decision and our revised proposal by the following elements: market expansion (section 6.1); capital contributions (section 6.2); the construction management fee (CMF) (section 6.3); capacity development (section 6.4); stay in business (section 6.5); non-system (section 6.6); corporate overheads (section 6.7); and labour and materials cost escalation (section 6.8).

6.1 Market expansion

Growing our customer base is an important element of our strategy to reduce network prices over time, and maintain the competitive advantage of natural gas in Canberra, Queanbeyan and Palerang. New economic connections have always been the foundation of our business's success and become even more important as natural gas competes more aggressively with other fuels.

Market expansion capex (ME capex) is required to safely and efficiently connect new customers to the gas network. It involves expenditure on new connection assets – mains (including internal mains), services, meters and associated equipment such as meter kits, meter data loggers and metretek devices.

In simplified terms, our forecast approach for ME capex in the initial proposal was to aggregate individual ME capex forecasts for each of the five new connection types: new estates, electricity-to-gas conversions (E-G), medium-density/high-rise, I&C tariff and I&C contract (including other non-routine connections). The forecast method for the first four connection types (collectively referred to as "tariff V connections") is a multiplication of three variables:

1. the forecast of the number of connections for the relevant connection type;
2. ratios of forecast activity volumes for each connection type – metres of mains, number of services, number of meters and volumes of associated equipment required to deliver each connection for the relevant connection type;
3. the unit rates for mains laid, service pipes laid, and meters (both gas and water) forecast to be installed for the relevant connection type.

The forecast for ME capex for I&C contract (including other non-routine connections) was based on four years historical average capex for this category.

Applying these methods resulted in an initial proposal ME capex forecast of $58.57 million ($2015/16, escalated direct cost, including the CMF, excluding overheads).

The AER's ME capex forecast of $39.05 million ($2015/16, escalated direct cost, including CMF, excluding overheads) differed substantially from our proposal for a number of reasons, most of which reflect a difference of opinion on key inputs.

In our view the AER's forecast of ME capex has not been arrived at on a reasonable basis and is not the best forecast or estimate possible in the circumstances, as required by Rule 74 of the NGR. ActewAGL Distribution's revised ME capex forecast is set out in Table 6.2. The revised unit rate derivation model and forecast capex model are provided in Attachment 6.01.

Table 6.2 Market expansion capex ($million, 2015/16, escalated, including CMF, excluding overheads)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Initial proposal	11.11	12.03	12.13	11.86	11.43	58.57
Draft decision	7.56	8.04	7.86	7.89	7.70	39.05
Revised proposal	8.08	8.59	8.76	8.81	8.67	42.90

The following sections provide further details on key elements of the ME capex forecast namely, the medium-density/high-rise forecast, the application of real price escalation, internal mains for medium-density/high–rise connections, data inconsistencies, and forecast I&C contract and non-routine expenditure.

6.1.1 Medium-density / high-rise forecast

The AER expects a more granular medium-density/high-rise ME capex forecast to:

- take account of the AER's expectation of a downturn in large apartment developments; and
- reflect the potential for different capex requirements within this market segment.[52]

Additionally, the AER have indicated that it expects the Boundary Code to impact how developers use gas as an energy source in medium-density/high-rise developments.

In response to the draft decision we have prepared a more granular forecast for medium-density/high-rise developments, applying a bottom-up forecasting methodology. The method involves the following steps:

1. disaggregate the forecast of medium-density/high-rise connections into two components: a medium-density connection forecast, and a high-rise connection forecast;
2. predict how gas will be used by developers in medium-density and high-rise connections, and on that basis what type of connection assets are likely to be required for medium-density and high-rise connections;
3. forecast an efficient and representative set of unit rates for the various connection assets forecast to be used in medium-density and high-rise developments; and

[52] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-25

4. forecast the ME capex requirements for the 2016-21 access arrangement period applying the connections forecast from step 1, the connection asset requirements from step 2, and the forecast unit rates from step 3.

Further detail on each step is detailed below. We also set out where the each step is undertaken in the relevant model. If the explanations or model updates are unclear in any way, we would be happy to meet with AER representatives to answer any questions.

Step 1 – disaggregate the combined medium-density/high-rise forecast into separate medium-density and high-rise connections forecasts

Refer to the Market Expansion Unit Rates Model (attachment 6.01.02) sheet 'Calc|MD-HR meter' cells N21:P25.

The first step in preparing our revised, bottom-up, medium-density/high-rise ME capex forecast is to disaggregate the single revised medium-density/high-rise connection forecast into separate medium-density and high-rise connection forecasts for the 2016-21 access arrangement period.

As explained in the demand chapter of this revised proposal, ActewAGL Distribution has not accepted the AER's alternative medium-density/high-rise connections forecast. Our revised proposal is set out in Table 6.3 below.

Table 6.3 Forecast of medium-density and high-rise connections 2016/17 to 2020/21

	2016/17	2017/18	2018/19	2019/20	2020/21
Forecast MD/HR connections	1,066	1,280	1,330	1,330	1,260

To disaggregate the medium-density/high-rise forecast, we used a report from HIA[53] that provides a new dwelling forecast by state and territory, divided into separate houses and five multi-unit dwelling categories:

1. semi-detached, row or terrace house, townhouse or duplex, etc with one storey;
2. semi-detached, row or terrace house, townhouse or duplex, etc with two or more storeys;
3. flat, unit or apartment in a building of one or two storeys;
4. flat, unit or apartment in a building of three storeys; and
5. flat, unit or apartment in a building of four or more storeys.

We classified the first four dwelling categories as medium-density dwellings, and the fifth as high-rise.

Using these HIA forecasts, we have calculated an annual forecast dwelling ratio for medium-density to high-rise developments as set out in Table 6.4. The dwelling ratio is applied to the aggregated new connections forecast set out in Table 6.3 above to disaggregate it into the separate medium-density and high-rise connections forecasts. Note that, because the HIA report

[53] HIA 2015, *HIA Housing Forecasts – Dwelling Starts by dwelling type by state and territory*. Attachment 6.02

does not provide a disaggregated dwelling forecast for 2019/20 or 2020/21, we have adopted the 2018/19 forecast ratio for these years, which we consider to be reasonable given the minimal variability in the ratio over 2016/17 to 2018/19.

Table 6.4 Forecast ratio (rounded) of medium-density and high-rise dwellings 2016/17 to 2020/21

	2016/17	2017/18	2018/19	2019/20	2020/21
Ratio					
MD %	44%	46%	44%	44%	44%
HR %	56%	54%	56%	56%	56%
New Connections					
MD	470	583	579	579	549
HR	595	697	751	751	711

Step 2 – use of gas in medium-density and high-rise developments

Refer to the Market Expansion Unit Rates Model (attachment 6.01.02) sheet 'Calc|MD-HR meter' cells R21:Z25.

The second step is to forecast how gas will be used in medium-density and high-rise developments. It is challenging to forecast the how gas will be used in medium-density/high-rise dwellings over the period to 2020/21. A significant degree of judgment is required. Based on our experience and understanding of the ACT market, we believe that the following assumptions are reasonable as regards future supply configurations for medium-density/high-rise connections:

- one dominant medium-density configuration: each end-customer has an individual gas meter for cooking and/or heating and/or an individual gas instantaneous hot water unit (no hot water meter required);
- two potential high-rise configurations, each with 50% market share:
    - boundary-metered gas cooking and/or heating, with a centralised hot water system (which will require a boundary gas meter and individual hot water meters) (HR1); and
    - centralised hot water system only (which will require a boundary gas meter and individual hot water meters) (HR2).

It has been particularly challenging to forecast developers' future gas configuration preferences in high-rise sites. Although it may be expected that the Boundary Code will move developers away from gas cooking and heating, our new volume-boundary reference tariff facilitates developer access to a regulated network tariff for boundary-metered gas cooking. Given these uncertainties, we have adopted a simple 50/50 split for the two predicted high-rise development configurations.

The new connections forecast for each connection type is set out in Table 6.5.

Table 6.5 Forecast number (rounded) of medium-density and high-rise dwellings 2016/17 to 2020/21

	2016/17	2017/18	2018/19	2019/20	2020/21
New Connections					
MD	470	583	579	579	549
HR1	298	348	375	375	356
HR2	298	348	375	375	356

We then assessed asset requirements (mains, services, individual and master boundary meters, and associated equipment such as MDLs and meter kits) for each forecast medium-density and high-rise connection type. Our proposal is set out in Table 6.6. Each high-rise development is assumed to have 30 customers.

Table 6.6 Ratio of assets per meter (or customer) for each dwelling type

Connection asset	MD	HR1	HR2	Assumption
Metres of mains / gas meter	8.25	8.25	8.25	Based on 2010/11 to 2013/14 ratios; refer item 10 in 'Input|RP changes' worksheet of the revised proposal capex model.
No. of services / gas meter	0.68	0.68	0.68	Based on 2010/11 to 2013/14 ratios; refer item 10 in 'Input|RP changes' worksheet of the revised proposal capex model.
Gas meter and kit / customer	1	0	0	Per standard configure described in section 6.1.1. Every residential gas meter requires a meter kit (includes regulator and meter bar).
Hot water meters / customer	0	1	1	Per standard configure described in section 6.1.1.
Master cold water meter / customer	0	1/30	1/30	Every master hot water meter installation requires a master cold water meter to validate total water consumption.
Hot water master gas meter / customer	0	1/30	1/30	Per standard configure described in section 6.1.1.
Cooking & heating master gas meter / customer	0	1/30	0	Per standard configure described in section 6.1.1.
Master kit / master meter	0	1	1	Every master gas meter requires a meter kit (includes regulator, meter bar other fixtures).

Step 3 – unit rate for each connection asset

Refer to the Market Expansion Unit Rates Model (attachment 6.01.02) sheet 'Calc|MD-HR meter' cells AB9:AH11.

The third step is to apply the unit rates to each forecast connection asset requirement for each medium-density/high-rise connection type. Our proposal is set out in Table 6.7.

Table 6.7 Basis for forecast unit rates, by asset type

Connection asset	Unit rate proposal
Mains	Weighted average unit rate based on: • RY11 to RY14 mains jobs DAMS unit rates for mains jobs
Services	Weighted average unit rate based on: • RY11 to RY14 services jobs DAMS unit rates for services jobs
Gas meter and kit	DAMS unit rate for MK3D domestic meter kit. This kit is sized for residential gas consumption.
Hot water meter	DAMS unit rate. Refer to 6.5.3 for explanation of prudency and efficiency.
Master cold water meter	DAMS unit rate for 40mm cold water meter. This meter is sized for a 30 dwelling high-rise development.
Master gas meter (cooking/heating/hot water)	DAMS unit rate for AL425 gas meter (2205)
Meter kit for a master meter	DAMS unit rate for MA22, which is the meter kit for the AL425.

Step 4 – forecast ME capex for the next AA period

Refer to the Market Expansion Unit Rates Model (attachment 6.01.02) sheet 'Calc|MD-HR meter' cells AB21:AK25.

Our revised proposal forecast ME capex for the 2016-21 access arrangement period applies the connections forecasts from step 1, the connection asset requirements from step 2, and the forecast unit rates from step 3. Table 6.8 compares the total MD/HR ME capex forecast from our initial proposal, the draft decision and this revised proposal.

Table 6.8 Medium-density market expansion capex ($million, 2015/16, escalated, including CMF, excluding overheads)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Initial proposal	3.54	4.34	4.36	4.16	3.97	20.36
Draft decision	0.79	1.01	1.03	1.03	0.95	4.82
Revised proposal	0.96	1.16	1.30	1.30	1.27	5.99

6.1.2 Application of real price escalation

The draft decision has not included real price escalation in the ME capex unit rates because the AER was unable to identify escalator provisions in the DAMS, and the ASA only refers to CPI escalation.[54]

[54] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-27

We do not accept the AER's draft decision to not include real price escalation for market expansion unit rates.

The AER has considered the escalation terms in the contract between Jemena Asset Management (JAM) and its subcontractor (ZNX(2) Pty Ltd , or ZNX(2)) – i.e. the Asset Services Agreement (ASA). However, the more relevant contract is the DAMS, as we noted in our information request response 017. The DAMS requires that:

- the unit rates be adjusted annually by CPI (subject to a small number of caveats); and
- importantly, the unit rates be reset against benchmark market rates on the fifth anniversary of the Effective Time (the Effective Time is defined as 1 July 2013).[55]

Therefore, in practice, the ME capex unit rates will be reset to benchmark rates to apply from 1 July 2018. Thus, adopting the AER's rationale of considering contract escalator provisions leads to applying:

- CPI escalation in 2016/17, 2017/18, 2019/20 and 2020/21; and
- in 2018/19, a change in unit rates reflecting real price escalation to 1 July 2018, because unit rates are matched to benchmark market rates on 1 July 2018 (and market rates can be expected to reflect actual real price escalation to 1 July 2018).

Our revised proposal reflects this approach by:

- applying no real price escalation in 2016/17, 2017/18, 2019/20 and 2020/21
- applying real price escalators in 2018/19, that reflects real price escalation to 1 July 2018. The materials and labour real price escalators adopted to perform this calculation are consistent with our revised proposal approach to price escalation, as explained in section 6.8.3.

6.1.3 Internal main for medium-density/high-rise connections

The AER has removed the forecast cost of internal mains for villas from the medium-density/high-rise connections capex forecast because it considers:

- the cost should be paid by the developer because the internal main is contained within the property; and
- it is not industry practice for a network provider to charge customers for an internal main.[56]

Clause 3.3 of the Boundary Code stipulates that the boundary between a gas distribution network and a customer's premises is at the point of supply. The gas distribution network is

[55] Distribution Asset Management Services Agreement between JAM and ActewAGL Distribution, sections 3.2(a) and (b). Submitted as appendix 4.1 of AAD's initial proposal.

[56] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-28

owned by ActewAGL Distribution. The point of supply is defined by the Code as the outlet of the meter assembly.

For villas and similar developments, the connection assets up to the outlet of the meter assembly includes mains in gazetted streets, internal mains, services and the meter assembly. Internal mains are part of the connection assets up to the outlet of the meter assembly. Therefore, they are part of the ActewAGL Distribution owned gas distribution network.

We do not charge developers for internal mains (or other connection assets) simply because they are on the villa (or any other) site. Any developer charges will follow from a capital contribution calculation that assesses the economics of the connection (or connections). The presence of internals main does not necessarily preclude a particular development from being economic (NPV>0). We encourage the AER to consider the current Jemena Gas Networks merits review of allowed tariff D connection costs when considering this issue.

The AER also does not think it is appropriate to include internal mains costs in the capex forecast because other distributors do not charge customers for an internal main. It is not clear how the practice of other distributors is relevant to whether the capex is conforming under Rule 79. The AER must approve the capex forecast if it meets the requirements of Rule 79. The AER would be in error to do otherwise. In our view this capex clearly meets the requirements of Rule 79 as offering connections is a regulatory obligation. Internal mains are part of the connection assets owned by ActewAGL Distribution.

6.1.4 Data inconsistencies

Appendix B of the draft decision's capex attachment sets out a comparison of certain connections data included in the ME capex unit rate model and Regulatory Information Notice response, and questions why the data does not reconcile.

We have reviewed the comparisons set out in Appendix B. We note that the AER uses the version of the RIN submitted with the initial proposal submitted 30 June 2015, rather than that subsequently submitted on 31 July 2015. Using this updated RIN data reduces some of the differences quite considerably. Nonetheless, there are still differences.

The main reason for the differences is due to different data sources being used to populate the RIN and unit rate model. The version of the unit rate model submitted with the initial proposal used mains and services job data from information system GASS+, and meter job data sourced from invoicing spreadsheets. The RIN data for mains, services and meter jobs was sourced from invoicing spreadsheets. The invoicing spreadsheets provide data on a different basis to GASS+, and so assumptions were made in preparing the RIN data. Our review of the data indicates that this led to discrepancies.

We have repopulated the unit rate model using job data from GASS+ for meters. We have not used GASS+ for meter kits and MDLs because the data is not readily available and would require cleansing. This has not been possible in the time provided by the AER to prepare the revised proposal.

6.1.5 I&C contract and non-routine

The AER's draft decision did not include any forecast expenditure related to I&C contract connection expenditure as the AER considered it could not verify historical expenditure.[57]

Table 6.9 sets out the historical expenditure, which was averaged and included in the capex forecast.

In preparing this revised proposal we identified that this expenditure did not solely relate to the I&C contract market segment. Non-routine connection expenditure for other market segments has also been captured. Accordingly we have renamed this category 'I&C contract and non-routine' expenditure.

Typically non-routine connection costs are incurred where a high-pressure connection is made using steel pipes, for instance in providing a high-pressure connection to a new development. As these costs are non-routine, as outlined in our June 2015 submission[58], there are no applicable unit rates.

We note that these costs have not been separately reported in the historical RIN data but instead have been included in the 'I&C tariff category.' However, these costs have been separated out in a discrete connection category in the unit rate model. We confirm that there has been no double counting of expenditure as the remainder of the ME capex forecast is composed using only unit rates. In contrast this I&C contract and non-routine expenditure reflects costs that are not unit rate based.

In this revised proposal we have retained this expenditure to ensure that the forecast is the best forecast or estimate possible in the circumstances, as required by Rule 74 of the NGR.

Table 6.9 Historical I&C contract and non-routine capex ($million, 2015/16, escalated, including CMF, excluding overheads)

	2010/11	2011/12	2012/13	2013/14	Average
Historical I&C and non-routine capex	0.2	0.35	0.22	0.20	0.24

6.2 Capital contributions

Capital contributions are required from customers or land developers when the cost of connecting the customer or the new residential area is less that the net present value (NPV) of the additional revenue from the new customer or customers (net of incremental operating costs). The capital contribution is calculated to ensure that the NPV of the new connection or connections is positive.

[57] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-28

[58] ActewAGL Distribution, *2016-20 access arrangement information, Attachment 4: Efficient delivery of services,* p.17

In the draft decision the AER indicated that it was unable to verify ActewAGL Distribution's proposed capital contribution amounts and forecast a capital contribution of $4.1 million ($2015/16).[59]

We have considered the AER's draft decision and accepted the AER's forecast. We have included this amount in our revised proposal, lowering proposed conforming capital expenditure.

6.3 Construction management fee

As outlined in our June 2015 submission, on behalf of ActewAGL Distribution JAM subcontracts capital works under $500,000 to ZNX(2) through an ASA. These costs have two components:

- the CMF, which includes the fixed costs incurred in managing routine works; and
- a set of unit rates which reflect the marginal cost incurred in undertaking a unit of work.

Our initial proposal included a CMF step change, required to comply with changes to the Gas Safety and Installation Code, Gas Network Boundary Meter Code and Gas General Metering Code.[60] We also applied labour price escalation to reflect expected changes in input cost. No materials escalators were applied.

The AER considered the CMF prudent and efficient but did not include the proposed step change to the CMF.[61] The AER also removed real price escalation.

After considering the AER's draft decision we have decided to accept the removal of the CMF step change. However, we consider that real price escalation should remain.

Unlike unit rates, which we note in section 6.1.2, are adjusted annually by CPI (subject to a small number of caveats), the CMF charges reflect actual costs incurred.[62] As detailed in information request response 019 Construction Management Fee, the CMF is largely made up of labour costs. Consequently, in our revised proposal we have continued to apply labour escalators to reflect the best forecast or estimate possible in the circumstances, as required by Rule 74 of the NGR.

6.4 Capacity development

Capacity development capex is expenditure related to augmenting and maintaining the integrity of the services provided by the shared network, the underpinning infrastructure which supports supply to all consumers.

---

[59] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-29

[60] ActewAGL Distribution, *2016-20 access arrangement information, attachment 6: capital expenditure,* p.41

[61] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-30

[62] See Attachment 4.01 to the June 2015 submission (The DAMS Agreement), schedule 4, clause 3.1.

Generally, capacity development expenditure is required to expand network capacity[63] in order to maintain supply to existing consumers and ensure the integrity of services. When the infrastructure only supports new consumers ActewAGL Distribution classifies this expenditure as ME capex.

Table 6.10 Capacity development capex ($million, 2015/16, escalated, including CMF, excluding overheads)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Initial proposal	3.02	5.23	2.73	6.57	1.14	18.70
Draft decision	2.84	1.21	0.71	0.27	1.16	6.19
Revised proposal	2.84	1.21	2.01	6.59	2.49	15.13

6.4.1 ActewAGL Distribution's proposal

The capacity development program was developed through the capacity planning process undertaken by JAM on ActewAGL Distribution's behalf, as detailed in our June 2015 submission.[64]

Over 80% of this capex in the initial access arrangement proposal is related to three distinct projects, being the Molonglo Primary Extension (stage 1) (Molonglo Primary), Molonglo Secondary Extension (stage 2) (Molonglo Secondary) and West Belconnen Secondary Main (West Belconnen Secondary).

These projects were included to ensure the integrity of services supplied to existing consumers is maintained by improving the resilience of the network. The new gas mains and associated facilities provide additional capacity to manage peaks and lessen the risk of a supply interruption while also improving security of supply.

6.4.2 The AER's draft decision

The AER did not accept ActewAGL Distribution's capacity development forecast. Instead the AER approved an alternative estimate of conforming capital expenditure which includes expenditure for West Belconnen Secondary and 24 smaller augmentation projects, but excluded the Molonglo Primary and Molonglo Secondary.

The AER considered that both the Molonglo Primary and the Molonglo Secondary would not be required in the 2016-21 access arrangement period.[65] In making this decision the AER relied on advice received from Sleeman Consulting.[66]

[63] In terms of peak hourly flow rate of the network rather than daily or annual throughput.

[64] ActewAGL Distribution, *2016-20 access arrangement information, attachment 6: capital expenditure,* pp.48-50

[65] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-32

6.4.3 ActewAGL Distribution's response

We have considered the AER's draft decision and Sleeman Consulting's advice and do not accept that expenditure for the Molonglo Primary and Molonglo Secondary is not required in the 2016-21 access arrangement period.

While we agree that new information—not available at the time our forecasts were prepared—indicates that both the Molonglo Primary and Molonglo Secondary can be deferred, we do not agree with that these projects can be deferred beyond the 2016-21 access arrangement period. Expenditure for these projects is still required in the 2016-21 access arrangement period to maintain the integrity of services and maintain capacity to meet levels of demand for existing services. Accordingly, these projects are justified under Rule 79(2)(c)(ii) and (iv).

We have prepared a revised capacity development forecast incorporating the updated timing for the Molonglo Primary and Molonglo Secondary projects.

We have also prepared a presentation,[67] which we would be happy present to the AER and Sleeman Consulting, that goes to addressing the concerns raised by the AER.

The Molonglo Primary and Molonglo Secondary are two distinct projects required to address two distinct network constraints. Accordingly, we provide further detail on each of these projects in turn below.

Molonglo Primary

The Molonglo Primary provides additional capacity to the shared network to alleviate a constraint at the secondary main along Streeton Drive (Streeton Drive Secondary). Without the Molonglo Primary, pressure will drop to a critical level[68], leading to potential restrictions of supply, and/or loss of supply, to consumers.

The AER did not accept forecast capex for the Molonglo Primary. The AER noted concerns raised in the Sleeman Consulting report around the peak load forecast and consideration of alternative options identified.[69] We agree that new information suggests that the Molonglo Primary can be deferred. However, capacity modelling incorporating the new information has determined that

---

[66] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-33

[67] Attachment 6.03

[68] Critical means below the emergency pressure level (which is again below the minimum design operating pressure of the network). When a network pressure is below the critical level supply will be unreliable and poor, district regulators may fail to operate effectively and close down. At this point operational measures will enacted, such as the active monitoring of the regulators by field personnel, adjusting pressure settings temporarily outside of normal operations etc. If unmonitored this may lead to a safety issue if loss of supply does occur.

[69] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-34

the project can only be deferred 1 year rather than beyond the 2016-21 access arrangement period.

Our reasoning is provided in two parts. First we respond to the concerns raised with the peak load forecast and implications for the new timing, and then we provide a summary of the alternative options considered.

Peak load forecast

We design and build the gas network to ensure that we can supply gas in a ‘1 in 20’ winter (which we define as ‘severe’), to ensure that we can provide reliable supply in the winter months of the coldest capital city in Australia.

The AER considered that ActewAGL Distribution’s modelling overestimated peak load, based on advice received from Sleeman Consulting. Sleeman Consulting’s analysis was based on a later dwelling forecast released by the ACT Government Land Development Agency than that used by ActewAGL Distribution in preparing the capex forecast.

We have considered this new dwelling forecast and agree that the Molonglo Primary could be deferred, but only by one year as the Molonglo Primary will be required by winter 2021. Our revised proposal reflects this updated timing.

Sleeman Consulting considered that our peak load estimate of 5,061 m^3/h in 2020 to be marginally high but not unrealistic.[70] We note that this estimate is for base load peak demand. Peak load in a severe winter would be higher, as outlined in Table 6.11.

Table 6.11 Peak load forecast for Molonglo ($million 2015/16)

	Base (m3/h)	Severe winter (m3/h)	Minimum pressure (kPa)
Winter 2018	3623	4203	709
Winter 2019	4342	5037	655
Winter 2020	5061	5870	599
Winter 2021	5779	6704	533 (Critical)
Winter 2022	6498	7538	454 (Critical)

If a severe winter in 2021 occurs without the Molonglo Primary in place then our customers will experience either restricted or loss of supply – when they rely on, and value, the supply of gas the most. There is also a safety risk arising from air ingress into the gas network when pressure is low and as such the project is also justified under Rule 79(2)(c).

It is important to note that consumer feedback supports maintaining the level of reliability provided to the ‘1 in 20’ standard. Our Energy Consumer Reference Council indicated that our

[70] Sleeman Consulting 2015, *Review of Capex Forecasts for Selected Projects Report to Australian Energy Regulatory,* p.3

consumers place a high value on safety and reliability.[71] Moreover we have conducted willingness to pay studies to understand how consumers value trade-off between price and service attributes, such as frequency, duration, time of year and time of day of service interruptions. A key result from our most recent study of 274 residential consumers in 2011, peer reviewed by Professor Riccardo Scarpa (a recognised expert in the field of choice modelling), found that:

> *Despite the fact that households are now less likely to agree that the prices for utilities services are reasonable (than they were in 2003), comparisons with the findings of the NERA and ACNielsen study show that households are now willing to pay more to avoid gas supply interruptions.*

This result indicates that consumers are not willing to accept a lower reliability standard in return for a lower price and affirming ActewAGL Distribution's target reliability standard.

Alternative options

The AER noted that information on alternative options to address supply constraints was not presented. The AER stated:

> *ActewAGL did not provide any information to demonstrate whether or the extent to which it has considered more optimal choices to meet any forecast constraints other than extensions to the primary and secondary systems.*[72]

The AER cited Sleeman Consulting who noted that:

> *If and when the Molonglo Primary Extension is required, consideration should have been and should still be given to alternative and potentially more optimal approaches that do not necessitate significant extensions of both the primary and secondary systems. For example, consideration could have been given to designing and constructing the Molongo Secondary Extensions to have capability for upgrading of their operating pressure, potentially to primary level, thereby avoiding the need for parallel extensions.*[73]

Assessing alternative solutions to address network constraints occurs as part of our continual assessment of the optimal design of the gas network. Our long term focus ensures that the right network is constructed in the long term interests of consumers. Below we outline how the historical network design decisions we have made were in the long term interests of consumers. We also provide detail on alternative options we considered to identify that the Molonglo Primary is the best solution to relieve the network constraint.

---

[71] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 1 – Consumer Engagement p.16

[72] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-34

[73] Sleeman Consulting 2015, *Review of Capex Forecasts for Selected Projects Report to Australian Energy Regulatory,* p.4

Our long term focus is evident in the construction of the existing network in Weston Creek. The medium-pressure network is supported by a series of secondary mains, including the main along Streeton Drive, which were sufficient to maintain supply. At the time the network was constructed (the Streeton Drive Secondary was commissioned in 1981) the Molonglo suburb was not envisaged. Molonglo was first included as part the strategic plan for Canberra 23 years later as part of the 2004 Canberra Spatial Plan.[74]

Given that the Weston Creek area could be supplied with secondary mains and Molonglo was not part of the strategic plan for Canberra, no primary main was required and none was installed.[75]

A different approach is required for the Molonglo area as the secondary network (unlike in Weston Creek) will need support from the primary network in the future. Although the Molonglo Primary will be built to primary standard it will initially operate at secondary pressure and alleviate the forecast constraint on the Streeton Drive secondary. As the Molonglo area grows the Molonglo Primary will be able to operate at primary pressure and provide supply through a Primary Regulatory Station (PRS) to the secondary network in Molonglo.

The installation of the Molonglo Primary by winter 2021 is the lowest cost option. The next best alternative is the duplication of the Streeton Drive Secondary (at least $2.2m). However, the Molonglo Primary (operating as a secondary main) will still be required in winter 2023. The additional cost of the Streeton Drive duplication exceeds the time value of money advantages from deferring the Molonglo Primary by two years.[76] Consequently, the alternative option has a higher total forecast cost and has therefore not been proposed by ActewAGL Distribution.

Molonglo Secondary

The AER considered that the Molonglo Secondary was not required as it considered, based on advice from Sleeman Consulting, that any gas requirements in the early stages of the Molonglo Development could be met through existing infrastructure.

As with the Molonglo Primary, Sleeman Consulting relied on an updated dwelling forecast from the ACT Government Land Development Agency. We have considered the AER's draft decision, the Sleeman Consulting report and updated dwelling forecast from the ACT Government Land Development Agency.

---

[74] The Molonglo suburb was first identified as part of the 2004 Canberra Spatial Plan. See Attachment 6.04: ACT Government 2004, *The Canberra Spatial Plan*, p.31

[75] Installing a primary main in Weston Creek would have been uneconomic even with perfect foresight, as a primary main operating a primary pressure cannot deliver supply direct to the medium pressure network. A pressure regulating station (PRS) and a supporting secondary network are required to allow gas to flow from the primary to medium pressure network levels. Temporarily operating the main at secondary pressure does not avoid the additional redundant infrastructure which would have to be installed, either at the time the primary is laid or later on (with expensive restoration costs), before the main could operate at primary pressure.

[76] ~$1m based on a real WACC of 6% and a project cost of $8.4m.

We agree with Sleeman Consulting that the existing District Regulator set will be capable of supplying gas into the initial stages of the Denman Prospect development.[77] We also agree that, based upon the latest information, the Molonglo Secondary will not be required in the timeframe that we initially proposed (early 2019).

However, the Molonglo Secondary will be required to be in place by 2023 to avoid supply restrictions and loss of supply. While the bulk of the expenditure is forecast in the 2021-26 access arrangement period, some costs (relating to the assessment, requirements and definition phases) are expected to be incurred in the last year of the 2016-21 access arrangement period to ensure delivery prior to winter 2023. Our revised proposal reflects our proposed change in timing for the Molonglo Secondary.

6.5 Stay in business

Stay in business capex comprises capex on upgrading, renewing and replacing assets to meet regulatory obligations and ensure the safe and reliable operation of the network. Stay in business capex over the 2016-21 access arrangement period, has two components.

- *Network renewal and upgrade* – related to the replacement and upgrade of network infrastructure to ensure the reliable transport of gas through the ACT network, to ensure the integrity of the gas network infrastructure and replace outdated equipment.
- *Meter renewal* – expenditure for the replacement and upgrade of meters and related equipment.

Table 6.12 Stay in business ($million, 2015/16, escalated, including CMF, excluding overheads)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Initial proposal	6.80	7.69	8.09	4.31	4.54	31.43
Draft decision	6.58	7.33	7.17	4.43	4.82	30.33
Revised proposal	7.55	8.33	8.14	4.46	4.81	33.27

6.5.1 ActewAGL Distribution's proposal

ActewAGL Distribution forecast that over the 2016-21 access arrangement period a total of $31.43 million ($2015/16) would be spent on stay in business projects and programs. This expenditure related to:

- *Network renewal and upgrade* – key projects required included inlet piping rectification, the installation of a pressure limiting station at the Watson CTS, undertaking integrity digs and upgrading the compliance of facilities. Expenditure related to projects such as the installation of isolation values, on-site communications equipment and intelligent pigging was also included.

[77] Sleeman Consulting 2015, *Review of Capex Forecasts for Selected Projects Report to Australian Energy Regulator,* p.4

The proposed Network renewal and upgrade capital expenditure is justified under Rule 79(2)(c)(i) – (iv) as it is required to maintain the integrity and safety of ActewAGL Distribution's network and to ensure continued provision of existing services

- *Meter renewal* – this expenditure was for the replacement and upgrade of meters and related equipment as it reaches the end of its economic life (or is found to be defective) to ensure the safety of customers and accurate customer billing.

  Meter renewal and upgrade capex is required to replace aging and degrading meters and to meet the requirements of the *Utilities Act 2000* (ACT) and *Gas General Metering Code* administered by the ACT Environment and Planning Directorate, and the NSW Department of Fair Trading which administers the regulation for NSW. Accordingly, it is justified as conforming capital expenditure under Rules 79(2)(c)(ii), 79(2)(c)(iii) and 79(c)(iv).

6.5.2 The AER's draft decision

The AER did not accept ActewAGL Distribution's forecast stay in business capex. The AER substituted an alternative capex forecast. The forecast was based on the forecast capex proposed by ActewAGL Distribution, but with four adjustments:

1. A reduction of $0.6 million (revised from $1.9 million to $1.3 million) in expenditure to build the Watson CTS pressure limiting station, based on advice from Sleeman Consulting (network renewal and upgrade).[78]
2. The removal of $1.4 million required to implement the ACT facilities compliance program as the AER considered that the need for the project was not demonstrated (network renewal and upgrade).[79]
3. A reduction of $0.4 million as the AER considered that the most cost-effective and reliable hot water meters were not selected.
4. The removal of $0.02 million required for ActewAGL Distribution funded relocation projects.

6.5.3 ActewAGL Distribution's response

ActewAGL Distribution has considered the AER's draft decision. In relation to the four adjustments:

1. *Watson CTS pressure limiting station* – we accept the draft decision.
2. *ACT facilities compliance program* – we do not accept the draft decision and maintain that this project is justified under Rule 79. Below we provide further explanation for why

[78] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-36

[79] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-37

this project is needed, and is justified under Rules 79(2)(c)(i) – (iv). We have also revised our proposal to incorporate an updated cost forecast.

3. *Hot water meters model type* – we do not accept the draft decision as we do not consider the hot water meter selected by the AER to be a prudent option, and therefore the alternative forecast does not comply with Rule 79(1).
4. *ActewAGL Distribution funded relocation projects* – we do not accept the draft decision as we consider this expenditure is required.

Further details on each adjustment are provided below.

Watson CTS pressure limiting station

Following consideration of the Sleeman Consulting report and the AER's draft decision we have reviewed the proposed costs for undertaking the Watson CTS pressure limiting station. We accept that the scope of work for the Watson project is less than the Coolamon POTS upgrade and in turn would require less capex. Therefore we have accepted the AER's draft decision on this project and revised our proposal accordingly.

ACT facilities compliance program

In regards to the ACT facilities compliance program both Sleeman Consulting and the AER considered that instances of non-conformance on another gas distribution system do not establish the case for ActewAGL Distribution's proposal.[80]

ActewAGL Distribution agrees that, in general, non-conformance on one gas distribution system does not establish that non-conformances exist on another. However, in many respects the ActewAGL Distribution gas network and the Jemena Gas Networks NSW gas network are alike, as they have been built and managed by the same organisation.[81]

Since our June 2015 submission we have conducted electrical and instrumentation holistic audits on four sites (attachment 6.05) confirming that the ACT facilities compliance program is required. We therefore maintain that this project is justified under Rules 79(2)(c)(i) – (iv).

We have also updated the forecast expenditure required for this project to reflect the outcomes from these audit reports and have incorporate the updated forecast in our revised proposal.[82]

Hot water meters

The AER did not accept ActewAGL Distribution's hot water meter approach for either new connections (as part of market expansion) or replacement (stay in business). The AER considered

[80] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-37 and Sleeman Consulting 2015, *ActewAGL Access Arrangement 2016-21 ACT Queanbeyan and Palerang - Review of Capex Forecasts for Selected Projects,* p.13

[81] A history of the ActewAGL Distribution partnership and how the gas network was installed and has been operated is provided in section 4.1 of Attachment 4 of our June 2015 submission.

[82] Updated costs are provided in confidential attachment 6.06

that ActewAGL Distribution applied a unit rate for a hot water meter which is materially more expensive than three other hot water meter types. The AER noted that:

> *On the information available, we cannot see why it would be appropriate for ActewAGL to use the materially more expensive hot water meter than the alternatives recommended in the tender reports. We therefore have not accepted ActewAGL's proposed step change for hot water meters on the basis that using the more expensive hot water meters would result in a forecast that is not arrived at on a reasonable basis.*[83]

To assist the AER we attach a confidential document explaining JAM's approach to prudently and efficiently managing hot water meters on behalf of ActewAGL Distribution (attachment 6.07). This report explains how the hot water meter approach delivers the best overall outcome for consumers when reliability, accuracy, cost and risk are considered. Each of these factors are interrelated. The cost of a strategy cannot be evaluated purely on the upfront cost of a meter. The replacement costs of the meter, which is dependent life of the meter and the probability of a failure must be taken into account. Further the costs to consumers from the inconvenience of inaccurate billing and early replacement of the hot water meters must also be considered.

When these factors are all taken into account the hot water meter chosen by ActewAGL Distribution has the lowest life cycle costs and is likely to cause the least amount of inconvenience to consumers. For this reason the capex proposed by ActewAGL Distribution is conforming capex as per Rule 79(1).

ActewAGL funded relocation projects

From time to time ActewAGL Distribution is requested by a third party to relocate assets. In a majority of cases the third party covers this cost. However, ActewAGL Distribution cannot recover the cost when it does not have the right guaranteeing the location of its assets, (e.g. on road infrastructure such as bridges, leased land or privately held land where no license or easement exists). ActewAGL Distribution included $20,000 for these costs.

We also provided the AER two examples of where infrastructure was required to be relocated to maintain both the integrity of supply and safety of services following changes to the environment from when the infrastructure was first installed.[84]

The AER removed these costs in its draft decision modelling, but provided no explanation for why these costs were removed.

Our revised proposal has retained these costs as they are necessary to maintain and improve the safety of services and maintain the integrity of services and therefore justified under Rule 79(2).

---

[83] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-26

[84] See response to information request 007 third party relocations.

6.6 Non-system capex

ActewAGL Distribution proposed $0.5 million (2015/16) for non-system capex. The AER stated that it is satisfied that the estimate of costs has been arrived at on a reasonable basis and is consistent with Rule 79 and is necessary to maintain the integrity of services and to improve the safety of services and is therefore justified under Rule 79(2)(i) and (ii).[85] ActewAGL considers that this decision achieves the NGO to the greatest extent.

6.7 Corporate overheads

In our June 2015 submission we applied corporate overheads in accordance with the CAM consistent with the methodology approved to apply for our electricity network. The new CAM allocates a proportion of corporate costs to the capex program better reflecting the role corporate costs have in supporting the capital program.

The AER, in its draft decision, found the overhead allocation rate to be prudent and efficient.[86] The AER applied ActewAGL Distribution's proposed allocation rate to the AER's alternative capex estimate. Importantly, the rate only changes the proportion of overhead costs allocated to capex and opex rather than total overheads. Any change to the amount of overheads allocated to capex must also be reflected in the opex forecast.

While we do not accept the AER's alternative capex estimate we do consider that the AER's decision to accept our proposed overhead allocate rate achieves the NGO to the greatest extent. We have maintained this methodology and applied the allocation rate to our revised capex forecast.

6.8 Labour and material cost escalation

In this section we outline our proposal, the AER's draft decision and our revised proposal in regards to labour and material cost escalation, specifically this section addresses whether material escalation should be applied and which labour escalators are used. The application of these escalators to ME capex and the construction management fee are covered in sections 6.1.2 and 6.3 respectively.

6.8.1 ActewAGL Distribution's proposal

In our June 2015 submission we included an estimate of the impact of price changes of labour and materials in forecast capex, through the application of real price escalators. These escalators are designed to predict the price changes to the expenditure categories that are inputs to ActewAGL Distribution's capital expenditure, which mostly consists of specialised labour to install

[85] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-38

[86] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-38

mains, connections of meters and station construction, plus the cost of combined materials used (e.g. a length of steel main).

The AER's expenditure forecast assessment guideline recognises the need to forecast both labour and material price escalation noting that '…labour prices changes are an important consideration when forecasting expenditure.'[87] and '[m]aterials price changes are an important driver of costs, particular capex, given their potential volatility'.[88]

6.8.2 The AER's draft decision

In the draft decision however, the AER was not satisfied that a forecast of real cost escalation for materials is robust and considered it could not determine a robust alternative forecast. The AER considered that real cost escalation over and above CPI should not be applied.[89]

The AER did accept the application of labour cost escalation as the AER considers it more reasonably reflects a realistic expectation of the cost inputs required to achieve the capex objectives.[90] However, the AER did not accept the proposed labour escalators and instead substituted escalators calculated on an average of different forecasts.[91]

6.8.3 ActewAGL Distribution's response

In regards to the material cost escalation we do not agree with the AER that the proposed real cost escalation was not robust nor that no material cost escalators should be applied. However, we have decided to accept the AER's draft decision and have not applied material cost escalators in our revised proposal. The consequence of this is a conservative revised capex forecast.

We have also accepted the AER's labour cost escalators.

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

[88] AER 2013, *Expenditure Forecast Assessment Guideline, Explanatory Statement*, p. 50

[89] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-53

[90] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 6 – Capital Expenditure p.6-54

[91] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21*, Draft Decision, Attachment 7 – Operating Expenditure p.7-20

7 Operating expenditure

7.1 Draft decision summary

The AER's draft decision on opex was $10.8 million ($2015/16) lower than ActewAGL Distribution's proposed forecast opex of $143.8 million ($2015/16) for 2016/17 – 2020/21. In addition, due to the AER's decision to include a true-up of 2015/16 revenue, it determined an opex allowance for 2015/16 to apply retrospectively.

The key areas of difference between our proposed forecast opex and the AER's draft decision are summarised below.

- The AER has rejected several of our proposed category specific forecasts and instead included these in its base-step-trend forecast.
- The AER has adopted a notional allowance of 20 per cent of costs associated with the 2016-21 access arrangement revision proposal and disallowed a step change for the 2021 access arrangement revision, instead of our proposal to fully remove these costs from the base and include a step change in the last three years of the next access arrangement period for the 2021 access arrangement revision.
- The AER has not accepted that our proposed rate of change was the best estimate of forecast price change, output growth and productivity growth in ActewAGL Distribution's circumstances, and instead applied alternative forecasts for each of these components of the rate of change.
- The AER has not accepted several of our proposed step changes, including those that are periodic in nature and not incurred in the base year, capex driven step changes, part of the IT asset utilisation fee, additional RIN reporting requirements, and the 2021 access arrangement revision project as noted in the second point above. The AER also revised our proposed change in capitalisation policy step change to reflect its capex decision.

Our response to these draft decisions and revised proposal are provided in this chapter.

7.2 Base year opex

7.2.1 Draft decision

The draft decision accepted 2014/15 as an efficient base year for forecasting opex. The AER made the following adjustments to base year opex:

- Removed $0.014 million for provisions reported in the RIN response;
- Removed ActewAGL Distribution's proposed $0.178 million in one-off costs included in JAM fees in 2014/15; and

- Removed 80 per cent of base year costs associated with the access arrangement revision project, leaving 20 per cent of these costs in base opex, but not accepting the related step change for the next AA revision project costs.
- Because the AER considered that several category specific forecasts should be included in the base-step-trend forecast, it did not remove these costs. This included insurance, water bath heater operations and ancillary services.
- The AER accepted that the utilities network facilities tax (UNFT), energy industry levy (EIL) and unaccounted for gas (UAG) should be separately forecast, and so removed these from total base year opex for the base-step-trend forecast.

With these adjustments made, the AER's draft decision estimate of base year opex was $18.6 million ($2015/16), compared with our proposed $16.9 million.

7.2.2 Response to draft decision and revised proposal

We have considered the AER's draft decision on base opex together with its draft decision on the efficiency carryover mechanism (ECM) carryover amount calculations. To assist us with this assessment, we engaged HoustonKemp to provide expert advice on the appropriate treatment of these costs, the interrelationship between forecast opex and the operation of the opex incentive mechanism and the manner in which that mechanism provides for a fair sharing of any outperformance or underperformance, (compared with efficient opex forecasts) between us as the regulated business and our customers.[92] This report is attachment at appendix 9.01.

In accordance with this report, and in light of our acceptance of the AER's approach to the application of the incentive mechanism proposed in the draft decision, including in particular the application of that incentive mechanism to opex in the 2014/15 base year, we have made some changes to our proposal on base opex. As previously foreshadowed, we have also incorporated the actual expenditure data for the 2014/15 base year in place of the forecast we had previously used (as actual data was not available at the time of our access arrangement information in June).[93]

[92] See appendix 9.01: HoustonKemp 2016, *Efficiency carryover mechanism*, 4 January

[93] ActewAGL Distribution, 2015, *2016 – 21 access arrangement information | Attachment 5: Operating expenditure,* p.20

7.2.2.1 Updated actual base year opex

In preparing our revised opex forecast, we have updated the starting point with actual opex in the base year. This is because at the time of preparing the opex proposal in our June 2015 submission, we did not yet have actual opex for the full 2014/15 year, and so base opex reflected actual expenditure to February, with remaining months based on budget forecasts.

ActewAGL Distribution's actual 2014/15 total opex used as the starting point for our revised opex forecast was $28.6 million ($2015/16), $0.7 million higher than forecast based opex of $27.8 million ($2015/16). The $0.7 million variance is driven mainly by:

- Higher than forecast UFT and EIL costs (+$0.2 million);
- Higher than forecast corporate services charges (+$0.5 million) following improvements being made in the cost allocation methodology whereby the main allocation driver is now estimated effort, rather than the previous drivers of the business' FTE numbers and total opex. This resulted in additional costs being allocated to the gas network business through the annual true up process for the corporate services charge. Note that these additional costs are included in the corporate services charge and not included as part of the access arrangement revision project budget upon which the access arrangement revision project step change forecast is based.
- Other minor offsetting positive and negative variances between forecast and actual amounts.

As explained in chapter 9, we have updated the ECM model with actual base year opex for calculating the carryover amounts to be applied in determining total revenues for 2016/17 - 2020/21.

7.2.2.2 Base year adjustments

We do not agree with the AER's base year adjustments and have revised our position on base year adjustments for our revised opex proposal to ensure consistency between base opex and our position on the calculation of ECM carryover amounts. Reasons for our acceptance of the AER's draft decision on the calculation of ECM carryover amounts are explained in section chapter 9 of this response to the draft decision. Our acceptance of the draft decision on this matter is on the expectation that the AER will correct the excessive penalties imposed on ActewAGL Distribution through the combined operation of the AER's draft decisions on the application of the ECM and the base opex for opex forecasting purposes, and so ensure the principles and intentions of a continuous incentive mechanism that inform the AER's approach to the application of the ECM are upheld.

Our revised position on base year adjustments is provided below.

7.2.2.2.1 Provisions

The AER has not explained why it has made an adjustment to exclude $0.014 million in provisions from ActewAGL Distribution's base opex, and it is not clear to us why this adjustment has been made. We note that the AER has made a corresponding adjustment to actual base year opex for the purpose of calculating the ECM carryover amount. Notwithstanding the AER's lack of explanation for this base opex adjustment, we have adopted this treatment in our revised opex proposal, as well as the AER's exclusion of this expenditure amount from the calculation of ECM carryover amounts so as to ensure that the required relationship between base opex and the ECM is maintained.

7.2.2.2.2 Reset Project and DAMS Agreement costs

The draft decision forecasts opex using a 'base-step-trend' approach with 2014/15 as the base year. However, in determining efficient base year opex, the draft decision:

- included only 20 per cent of the 2014/15 costs associated with the preparation of a revised access arrangement proposal (access arrangement revision project costs); and
- removed entirely the one-off costs arising from allocation changes associated with the Distribution Asset Management Agreement (DAMS costs).

Our initial proposal also removed these costs from the base year for the purposes of forecasting opex. However, we suggested that approach in the context of our initial proposal that the ECM would be closed out in 2014/15 and restarted in 2016/17, a zero incremental efficiency gain (loss) would be ascribed to the 2014/15 base year under the ECM and a step change would be included to address access arrangement revision project costs.

The draft decision proposes an alternative approach to the ECM under which that incentive mechanism is not closed out but continues to operate, and a non-zero incremental efficiency loss is ascribed to the 2014/15 base year under that ECM. As is explained in chapter 9 and set out in appendix 9.02, we now accept the approach to the application of the ECM set out in the draft decision.

In consequence, and in contrast to the draft decision, our revised opex forecast has been calculated using actual expenditure incurred in the base year, including the access arrangement revision project costs and DAMS costs, as the starting point for forecasting opex for 2016/17 - 2020/21. We explain below the reasons for our view that this is the correct approach.

The ECM is intrinsically linked to the forecasting approach to opex. It is by applying an ECM in combination with a revealed cost base-step-trend forecasting approach that a service provider is provided with a continuous and time-invariant incentive to achieve efficiency gains and the providers and consumers share efficiency gains 30:70. Where opex is not forecast using a single year revealed cost forecasting method, the ECM may not share efficiency gains (losses) 30:70 between the service provider and consumers, there is a risk the ECM may provide windfall gains or losses, and the ECM's objective of delivering a continuous and time-invariant incentive for the service provider to make efficiency gains will be undermined.

This inter-relationship between an ECM operating in one regulatory period and the approach to forecasting opex for the next regulatory period has been recognised by the AER in section 1.3 of its Efficiency Benefit Sharing Scheme for Electricity Network Service Providers[94] (2013 EBSS), throughout section 2 of AER's accompanying Explanatory Statement Efficiency Benefit Sharing Scheme for Electricity Network Service Providers[95] (2013 EBSS Explanatory Statement) and, more recently, in the AER's final decision on the efficiency benefit sharing scheme for ActewAGL Distribution's electricity network[96] (see Attachment 9 of this final decision). In section 2.2 of its 2013 EBSS Explanatory Statement, in particular, the AER recognised the need for consistent treatment of one-off factors in the base year as between the calculation of efficiency carryover amounts arising from the incentive scheme applicable in one regulatory period and the base year opex used for forecasting opex for the next regulatory period. Similarly, the AER expressly recognised the inter-relationship between the operation of the ECM in the 2010/11 to 2014/15 access arrangement period and the forecasting of opex for 2016/17 - 2020/21 in its draft decision.[97]

Nonetheless, the AER's draft decision does not correctly reflect this inter-relationship. Whereas the AER includes our 2014/15 access arrangement revision project costs and DAMS costs in actual opex used to determine the 2014/15 incremental efficiency loss arising under the ECM, it nonetheless excludes those same costs from our 2014/15 base opex used to forecast opex for 2016/17 - 2020/21 with the exception only of 20 per cent of our access arrangement revision project costs.

ActewAGL Distribution contends that this approach imposes excessive penalties on it, and is inconsistent with the objectives of the ECM to effect a sharing by it in the incremental efficiency loss for 2014/15 of 30 per cent and provide it with continuous and time-invariant incentives to achieve opex efficiency gains.

We have obtained a report from HoustonKemp (attached as appendix 9.01) which discusses the operation of the ECM and why it would be incorrect to include the entire access arrangement revision project costs and DAMS costs in actual opex for the purposes of determining the incremental efficiency loss for 2014/15 to be carried forward but to exclude all but 20 per cent of the access arrangement revision project costs for the purposes of determining forecast opex in

[94] AER 2013, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November, pp. 6 to 7

[95] AER 2013, *Explanatory Statement Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November

[96] AER 2015, *Final decision ActewAGL distribution determination 2015-16 to 2018-19 – Attachment 9 - Efficiency Benefit Sharing Scheme,* April, pp20-22

[97] AER 2015, *Draft decision, ActewAGL Distribution Access Arrangement, 2016-21 – Attachment 7 – Operating Expenditure,* p7-13

2016/17 - 2020/21. HoustonKemp demonstrates that the effect of the AER's adjustments to base year opex in its draft decision is:

- the imposition on ActewAGL Distribution of excessive penalties in relation to our access arrangement revision project costs and DAMS costs, which effects an unanticipated retrospective change to the intended incentives under and operation of the ECM;
- an unfair sharing of efficiency gains and losses between ActewAGL Distribution and consumers; and
- the undermining of the ECM objective of continuous and time-invariant incentives for ActewAGL Distribution to achieve opex efficiency gains.

In essence, this is because the penalty associated with any overspend by ActewAGL Distribution in the 2014/15 base year is not matched with an equivalent increase in forecast opex for 2016/17 - 2020/21 such that the draft decision allocates to ActewAGL Distribution much more than 30 per cent of the incremental efficiency loss in the base year.

ActewAGL Distribution further observes that, in circumstances where the AER has not sought to ascertain whether expenditure in other opex cost categories was unusually low in 2014/15, the exclusion of our access arrangement revision project costs from base year opex is likely to result in a biased forecast of efficient opex. An analogy can be drawn with the AER's discussion, in its 2013 EBSS Explanatory Statement, of opex cost categories with 'lumpy' expenditure profiles. There, the AER expressly stated that, even in the presence of particular opex categories that are lumpy, opex should still be forecast based upon actual expenditure in the base year provided that overall opex is not lumpy. Specifically, the AER observed:

> *'The EBSS works as follows … The actual opex incurred in the base year is used as the starting point for forecasting opex in the next regulatory control period.'*[98]
>
> *'We have further considered the interactions between the forecasting approach and the form of the EBSS. We agree with Incenta Economic Consulting that caution is required where there are significant lumpy costs. However, the question is not whether individual cost categories are lumpy but whether total opex is lumpy. … If total opex is not lumpy, then a revealed cost forecast is appropriate regardless of whether individual categories are lumpy or not.'*[99]

In the context of selecting the appropriate base year, the AER expressly acknowledged in the draft decision that ActewAGL Distribution's opex is relatively stable across the 2010/11 - 2014/15 access arrangement period. Specifically, the AER stated:

[98] AER 2013, *Explanatory Statement Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November, p.7

[99] AER 2013, *Explanatory Statement Efficiency Benefit Sharing Scheme for Electricity Network Service Providers,* November, p.30

'ActewAGL's opex is relatively stable across the 2010-15 period. While there is an increase in 2014-15 opex when compared to opex in 2013-14, the level of 2014-15 opex expenditure is consistent when compared across the 2010-15 period.'[100]

In consequence, the 'lumpy' expenditure profile for our access arrangement revision costs provides no basis for the draft decision failing to include the entire revealed access arrangement revision project costs in our base year opex for the purpose of forecasting opex for 2016/17 - 2020/21. Indeed, a decision to remove such costs would invite questions as to whether expenditure for other cost categories (which may have been unusually low in 2014/15) should be adjusted up for the purposes of forecasting opex.

As discussed above, we accept the AER's approach to the application of the ECM in its draft decision. This includes its decision to determine a non-zero incremental efficiency loss for the 2014/15 base year by reference to our actual opex in that year, inclusive of our access arrangement revision projects costs and DAMS costs. For this reason and having regard to the inter-relationship between the application of the ECM and the forecasting of opex for 2016/17 - 2020/21, in our revised proposal, we now propose that the forecast opex for each year of the 2016/17 - 2020/21 period should be based upon the actual costs incurred in the 2014/15 base year, inclusive of our access arrangement revision projects costs and DAMS costs. Our approach is consistent with the correct application of the ECM which is designed to provide a continuous and time-invariant incentive to achieve opex efficiency gains by sharing opex savings (or cost overruns) between ActewAGL Distribution and consumers in the proportion of 30:70.

7.2.2.2.3 Hoskinstown operation and maintenance contract costs

ActewAGL Distribution's opex forecast included a step change for additional costs for the renegotiation of the operations and maintenance (O&M) agreement for the Hoskinstown customer transfer station (CTS). We have considered the draft decision in respect of the step change for the renegotiation of the Hoskinstown O&M contract and the AER's reasons for rejecting the new costs for O&M of the Hoskinstown CTS as a step change. We agree that the O&M work currently performed by JAM is a business as usual service on ActewAGL Distribution's network. It is the unusually low price in the O&M contract with Jemena, and the circumstances leading to its renegotiation, that distinguish this proposed opex step change from others that the AER may consider to be recurrent, business as usual opex. As such, we have included an upward base opex adjustment of $0.04 million for business as usual Hoskinstown CTS O&M, rather than maintaining these costs as a step change. This amount is based on an average of these forecast costs between 2015/16 and 2021/21.

Full details of the requirement for this base year adjustment are provided in appendix 7.02.

[100] AER 2015, *Draft decision, ActewAGL Distribution Access Arrangement, 2016-21 – Attachment 7 – Operating Expenditure,* p7-15

7.2.2.3 Inclusion of additional cost categories in base opex

We have accepted the AER's draft decision to leave insurance, water bath heater operations and ancillary services costs in base opex. With regard to ancillary services opex, we note that our ancillary services opex included in base opex is on the basis that our proposed ancillary services charges are accepted. As these charges have been based on a cost build-up of these services, if these charges are not accepted by the AER in its final decision ActewAGL Distribution will not be provided with an opportunity to recover its efficient costs.

7.2.2.4 Revised base opex

As a result of the above considerations, our revised opex forecast has been formed from a starting point base opex of $21.4 million ($2015/16).

7.3 Rate of change

7.3.1 AER's draft decision

In the draft decision the AER does not accept ActewAGL Distribution's forecast of input price, output and productivity growth rates. The differences between ActewAGL Distribution's forecast and that in the draft decision are set out in Table 7.1:

Table 7.1 Rate of change parameter forecasts

Rate of change component	ActewAGL Distribution's proposal	Draft decision
Price growth	Applied BIS Shrapnel forecast of NSW and ACT for labour cost increases. Weightings: ACT: NSW - 53%: 47% Labour : non-labour - 61.4%: 38.6%	Applied an average of BIS Shrapnel and Deloitte Access Economics forecasts Weightings: applied ActewAGL Distribution's proposed weightings
Output growth	Capex-driven step changes for new High Pressure assets plus Incremental cost per customer of $26.04	Applied output growth weights from Economic Insights' report for JGN Throughput: 55% Customer numbers: 45%
Productivity growth	Zero productivity growth	Applied ACIL Allen productivity growth rate forecast of 0.50% on average p.a.

7.3.2 Response to draft decision and revised proposal

7.3.2.1 Price growth

While we consider our proposed labour escalation forecast to have been arrived at on a reasonable basis by our expert consultant BIS Shrapnel, we accept the AER's draft decision to apply an average of forecasts by BIS Shrapnel and Deloitte Access Economics. We have adopted the AER's draft decision on real price growth in our revised opex forecast.

7.3.2.2 Output growth

The AER's draft decision opex forecast includes a rate of change with output growth based on econometric analysis by Economic Insights undertaken for Jemena Gas Networks (JGN). This analysis determined output weights between throughput (55 per cent) and customers (45 per cent). The AER adopted these weights in the rate of change used to trend our opex forecast.

Appendix 5.01 of our 2016-21 access arrangement information submitted in June 2015 explained our concerns regarding the use of econometric and statistical modelling in the determination of opex forecasts. We maintain that this type of analysis should be used with caution due to issues with model selection, model parameter specification, multicollinearity between variables, data limitations, including limited sample size. We remain of the view that because of these issues, this type of analysis is best used alongside more robust evidence to test and support conclusions as well as to identify anomalies that require further investigation.

Noting these views, our initial opex forecast included an output growth forecast based on an 'incremental cost per customer' approach, coupled with a step change for new capex driven opex. This represented a 'bottom-up' approach to forecasting these costs.

We maintain that this bottom-up method for forecasting output growth reflects a better forecast that the top-down approach applied by the AER in its draft decision. Our forecast was arrived at on a reasonable basis and represents the best forecast possible in our circumstances.

Our bottom-up approach estimates costs based on the specific circumstances of the ActewAGL Distribution network, and is activity driven. That is, it is a better reflection of the actual efficient costs likely to be incurred and should therefore set a floor for the opex output growth forecast. The alternative approach in the draft decision applies the outputs of a generalised industry model that only accounts for high-level parameters relevant to the estimation of opex. In addition to the issues mentioned above and previously in our June 2015 submission, this type of analysis does not take into account some factors specific to ActewAGL Distribution's gas network, including:

- the high proportion of dual mains in ACT streets (in excess of 70 per cent of streets have a main on either side of the road), which impacts the meaningfulness of customer density as a model input;
- the ACT customer mix is heavily weighted towards small users, with a limited number of customers with demand in excess of 10TJpa compared to those connected to other networks;
- the very sharp peak in demand, which is a key driver of cost in the network (not throughput); and
- network layout and geographic differences, such as Canberra's largely non-grid layout based around town centres, which impacts ease of access to customers.

We are particularly concerned by the applicability of Economic Insights' output growth weights to ActewAGL Distribution's network, because these heavily weight output growth to throughput over customer numbers. We do not consider this to be appropriate for ActewAGL Distribution's gas network for the reasons set out below:

- Opex growth has, at best, a weak relationship to throughput growth or decline. A more important driver instead of throughput is peak demand, and while throughput is forecast to decrease, peak demand is forecast to increase. This is because network load factor is increasing as a result of the introduction of new high efficiency appliances that, while reducing energy requirements, impose a higher peak demand on the network.
- A small reduction in throughput has no impact on network opex. Existing assets will continue to require the same level of operating and maintenance costs, even if throughput being delivered by these assets declines.

These considerations were supported by ACIL Allen's analysis for ActewAGL Distribution, which found:[101]

> *A key characteristic of these [cost function] models is that the energy variable (TJ of gas throughput) has a negative coefficient. Moreover it is not statistically significant at the 1 per cent level in three of the five models. These results are not surprising given that gas throughput has been declining for the majority of distribution businesses over the period from 2005 to 2013, while operating expenditures have continued to increase.*
>
> *This suggests that energy (gas throughput) is no longer a key driver of increasing operating expenses for the nine gas distribution businesses under consideration. As a result an additional model specification is estimated excluding gas throughput.*

Consequently, we are of the view that if the AER maintains a preference for the use of a top-down forecast rather than our bottom-up forecast for output growth using cost function analysis output weights, ACIL Allen's analysis provides a more reasonable estimate of output growth, by excluding throughput as a variable and therefore applying 100 per cent of the weight to customer numbers and zero to throughput. However, we reiterate our view that econometric models must be applied with appropriate rigour. Notwithstanding the evidence presented above, there is no statistical test to assess which model is statistically more robust. Therefore we consider the next best alternative is to apply the average of the two consultants' models (Economic Insights and ACIL Allen), in a similar manner as has been applied by the AER in the draft decision for price growth.

Accordingly, ActewAGL Distribution's revised proposed opex forecast includes forecast output growth rates based on an average of the output weights derived by ACIL Allen and Economic Insights, as presented in Table 7.2 below.

[101] ACIL Allen Consulting 2015, *Productivity study ActewAGL Distribution Gas Network – final report*, 29 April, p. 31

Table 7.2 Output growth weights adopted in revised opex forecast (per cent)

	Economic Insights	ACIL Allen	Average
Throughput	55	0	**27.5**
Customers	45	100	**72.5**

7.3.2.3 Productivity growth

Our proposed opex forecast did not include a productivity growth factor. This was because we consider the ECM provides adequate incentive for productivity improvements and drives efficient costs. Notwithstanding this position, we engaged ACIL Allen to undertake a productivity study and provide estimates of forecast partial productivity factor growth rates to provide insight as to the general direction and size of ActewAGL Distribution's forecast productivity growth over the 2016-21 access arrangement period. Due to the general concerns we have about this type of analysis as explained above and in our appendix 5.01 of the 2016-21 access arrangement information, we did not believe that a suitably robust estimate was available, and considered that the most reasonable opportunity to recover at least our efficient costs was provided through no imposed productivity growth forecast, but continuation of the ECM.

The AER's draft decision did not accept our position on productivity growth and instead included a growth rate of 0.5 per cent per annum, based on ACIL Allen's analysis. In setting this rate in the draft decision, the AER also had regard to the forecast growth rate adopted by JGN of 0.59 per cent, and noted that these were similar.

We maintain our position that the most reasonable opportunity to recover at least our efficient costs is through the operation of the ECM with no explicit productivity growth rate applied to the opex forecast.

Nevertheless, we note the AER's preference to include a productivity growth factor in its opex forecasts, and in particular a preference to have regard to econometric model estimates in setting this forecast. If a productivity growth factor is to be included in opex forecasts, we consider it essential to consider this together with the setting of output growth rates when both are set using econometric model estimates.

Specifically, we note that the draft decision has taken results from two different reports by different experts for different businesses and mixed and matched the results in determining the output growth forecast (from Economic Insights' analysis) and productivity growth forecast (from Acil Allen's analysis). We are concerned that this results in an internal inconsistency in the two components of the forecast rate of change (productivity growth and output growth). The AER has not provided a rationale for this in the draft decision.

As with the output growth forecast, we consider Acil Allen's analysis provides a more reasonable estimate of productivity growth, as this analysis was undertaken specifically for ActewAGL Distribution's gas network. We consider it appropriate for the AER to adopt this as the basis for its forecast if it maintains its position that a productivity factor should be applied in its opex forecast. However, again noting our concerns regarding the robustness of this type of analysis and the need for consistency between the growth rates adopted for output and productivity, we consider the next best alternative is to adopt a similar approach as we have for output growth and apply the average of the two consultants' models (Economic Insights and Acil Allen).

To achieve consistency between the treatment of output and productivity growth, our revised proposed opex forecast includes forecast output growth rates based on an average of the average opex partial productivity growth factors estimated by Economic Insights for JGN (0.59 per cent) and Acil Allen for ActewAGL Distribution (0.50 per cent), resulting in an average of 0.55 per cent. By including these factors in our revised opex forecast, we consider it essential that the AER assess these together with the alternative output growth forecast we have presented. That is, we would not consider it appropriate for the AER to accept one without accepting the other.

7.3.2.4 Revised proposal rate of change

Taking into account our revised proposed approach to each of the elements of the rate of change as detailed above, the rate of change applied in our revised opex forecast is set out in Table 7.3 below.

Table 7.3 Revised forecast rate of change (per cent)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Price growth	0.28	0.41	0.60	0.75	0.75	0.91
Productivity growth	1.21	1.30	1.26	1.43	1.44	1.34
Output growth	0.55	0.55	0.55	0.55	0.55	0.55
Total rate of change	**0.95**	**1.16**	**1.31**	**1.64**	**1.64**	**1.70**

7.4 Step changes

7.4.1 AER draft decision

In the draft decision the AER only accepts ActewAGL Distribution's step change proposals for National Energy Customer Framework compliance, national business to business harmonisation and change in capitalisation policy, and partially accepts the IT asset utilisation fee (ITAUF) step change. The reasons for rejecting all or part of the other proposed step changes are set out in Table 7.4.

Table 7.4 Summary of the AER's reasons for rejecting proposed step changes

Step change	Summary of reasons for rejecting step change
IT Asset Utilisation fee	Costs associated with the replacement for the existing services provided by GASS+ on the assumed basis that the base year costs (that is existing fees from JAM) include costs associated with GASS+
Network risk and security management	There will be variation of opex activity from year to year and this will include periodic activities and the materiality is low
Hoskinstown O&M contract renegotiation	There is a business as usual service and the extent to which the additional cost arises from throughput increases it will be covered in the output growth component of the rate of change factor
Periodic inspections of exposed mains and water bath heater assets	There will be variation of opex activity from year to year and this will include periodic activities and these step changes are not material.
New capex-driven opex	Increased costs associated with capex-driven opex is appropriately covered through the output growth component of the rate of change factor
Revised metering and technical codes compliance	There is no increase in regulatory obligations, the need for increased inspections is part of business as usual activities, plus the expected year to year variation in activity
RIN reporting requirements	No expectation of increased reporting obligations
2021 access arrangement revision	Portion added to base year

7.4.2 Response to draft decision and revised proposal

We have maintained the following step changes in our revised opex forecast. In addition, we have added two new step changes. Our reasons are set out below.

Table 7.5 Revised opex forecast step changes ($million, 2015/16)

Proposed step change	Total
National Energy Customer Framework	0.77
National B2B harmonisation	1.05
IT asset utilisation fee	4.17
Network risk and security management	0.54
Periodic Inspections	0.30
2021 access arrangement review	4.03
Change in capitalisation policy	(5.51)
New tariff strategy implementation	0.78
Tariff variation notice gas quantities	0.14
Total	**6.28**

We accept the draft decision in respect of the following step changes:

- National Energy Customer Framework compliance,
- National business to business harmonisation,
- RIN reporting requirements,
- Change in capitalisation policy, and
- Revised metering and technical code compliance.

7.4.2.1 ITAUF

The draft decision does not accept the proposed opex step change for the increased ITAUF resulting from the replacement of the GASS+ system.

In not accepting this step change, the AER states that the replacement does not result in new functions, and continued delivery of business as usual services would be captured in base year opex. The draft decision also notes that the Customer Challenge Panel (CCP) suggested that the AER scrutinise this step change to ensure there was no double-counting of costs between JGN and ActewAGL Distribution.

We acknowledge that the AER's approach to considering opex step changes is not undertaken in isolation of its overall opex forecasting method. We understand this method assumes that base year opex is generally sufficient for recurrent opex, and generally it is only a change in service requirements (e.g. through a change in regulatory obligations) that may justify a change from a base year level of opex.

However we believe it is problematic to apply this forecasting method in this specific circumstance. The reason is that this particular IT investment would normally be considered *capex*.

The AER considered JGN's share of the GASS+ replacement project IT investment to be prudent and efficient capex for JGN's access arrangement review. The JGN GASS+ replacement project IT capex proposal was approved as prudent and efficient under rule 79.

For ActewAGL Distribution, however, this IT investment is charged by JAM through the DAMS fees, and it is only because of a technical requirement of Australian Accounting Standards (AAS) that we must treat this IT investment cost as opex. Under AASB 116, there are three elements to be satisfied for an Asset to be defined as a Property, Plant and Equipment Asset (and capitalised). These elements are:

- control;
- a 'past transaction or event' which gave rise to control; and
- the existence of 'future economic benefits'.

We do not "control" the OneSAP system—Jemena does. It is only because of this technical accounting requirement that we treat the IT charge from JAM as opex. The IT charge is not recurrent in nature (and therefore amenable to the base-step-trend method). From a regulatory forecasting perspective, the cost is more like capex in nature—it is a cyclical cost that reflects an IT asset lifecycle.

As such, we consider it is inappropriate to bluntly apply the AER's preferred opex forecasting approach in this particular circumstance. This IT investment cost is not recurrent. It is only because we do not control the IT asset in this case that we must treat this IT investment cost as opex under the Australian Accounting Standards.

In regard to the CCP's concern about the cost allocation, the cost reflects a 10.14 per cent allocation of the total GASS+ replacement project cost, based on customer number relativities across JGN and ActewAGL Distribution's gas network. We have been advised by Jemena that section 13.4.1 of the GASS+ replacement business case that JGN submitted with its June 2014 access arrangement RIN response will validate the cost allocation assumptions. We also note that the DAMS fees in the 2014/15 base year do not include a return on or return of capital associated with the GASS+ IT system because the GASS+ system had been fully depreciated by this time. There is, therefore, no issue of double counting or double recovery of both GASS+ and One SAP costs.

As such, we maintain that the full ITAUF step change of $4.2 million is required opex for the 2016-21 access arrangement period to ensure that we are able to fully recover our efficient costs.

7.4.2.2 Periodic step changes

The activities covered by the "Network risk and security management" step change and the "Periodic inspections of exposed mains and water bath heater assets" step change are periodic in nature, rather than recurrent. They are not activities undertaken every year, but at intervals of up to five years between activity. The activities nominated were not undertaken in the 2014/15 base year.

We do not consider the AER's draft decision that the amount forecast for these items is not material is an acceptable reason to reject a step change. While we acknowledge that there is some scope for variation in activity from year to year for opex, we consider the total value of these step changes of $0.8 million represent periodic costs that are not included in our base year opex, and are material.

For these reasons, we maintain the view that these periodic step changes should be approved and included in our opex forecast for the 2016-21 access arrangement period.

7.4.2.3 Capex-driven step changes

The capex-driven step changes proposed in our June 2015 submission relate to new opex associated with known additional high pressure assets that are essential to maintaining sufficiently reliable capacity in the network. These are assets operating at pressures greater than 1,050 kPa and form part of the Trunk and Primary systems. These costs do not include opex increases associated with other capex on ActewAGL Distribution's network which are estimated using the incremental cost per customer.

We have considered the AER's view that these costs are provided for as part of the forecast rate of change. We accept that the capex-driven step changes could be expected to be captured in an econometric approach to forecasting output growth, where that modelling is correctly specified and the costs derived are a reasonable representation of a gas network's actual cost drivers. However, there are several reasons why the use of the capex driven step changes – along with the incremental cost per customer – provides a better estimate of output growth.

As observed in the discussion of the rate of change above, the use the Economic Insight's output growth weights results in negative output growth. This is because output growth is weighted 55 per cent to throughput. As identified above, this result is completely at odds with the facts that despite declining throughput additional assets are required to maintain reliable supply, for which there must be additional opex. This does not appear to be acknowledged by the AER in its draft decision.

As explained above, there will be no reductions in opex for high pressure assets (other than that for the shutdown of Jerrabomberra POTS, which has effectively been replaced by the Hume PRS) and any estimate for output growth derived from econometric models would need to at least cover the estimate of costs using our 'bottom up' approach (capex driven step changes along with the incremental cost per customer based output growth) to reflect the addition of the new network assets, including the high pressure network assets. This is not achieved in the AER's draft decision which applies the Economic Insights cost function modelling, resulting in forecast negative output growth. This is because the capacity expansion capex, which drives the increased opex, can largely be attributed to growth in peak demand, for which throughput is an inadequate proxy.

The reason that additional high pressure capex and resulting opex is required, when throughput is declining, is that while throughput is declining peak demand is growing. This is a result of the appliance mix changing towards appliances that are more efficient, but have higher instantaneous demand.

In addition to the cost function models not reflecting the realities of efficient network cost increases, the estimates of the costs of the new opex activities, which were presented in ActewAGL Distribution's access arrangement proposal, provide better estimates because they reflect specific maintenance activities which have applied detailed costings.

As set out section 7.3.2.2, there is persuasive evidence for adopting our approach to forecasting output growth (capex-driven step changes plus incremental cost per customer on the Secondary and Medium pressure networks). However, if the AER is to apply a forecast of output growth using the econometric models, the output growth forecast should be sufficient to cover the additional costs to ActewAGL Distribution to meet the requirements of Rules 79 and 91.

As such, our revised opex forecast does not include the capex driven step changes, on the condition that our proposed output growth forecast is accepted. We maintain that these step changes are required if an alternative approach to output growth resulting in an inadequate allowance for these costs was to be applied by the AER in its final decision.

7.4.2.4 2021 access arrangement revision project

As noted in section 7.2, the AER's draft decision did not accept our proposed step change for the costs associated with the next access arrangement revision for the access arrangement expected to commence 1 July 2021, and instead adjusted the base year to leave 20 per cent of costs for the current project incurred in the base year in base opex. The AER did not explain its reasoning for this treatment, or for the 20 per cent allocation of costs in the base year.

We do not accept this decision and have maintained the need for a step change for the next access arrangement revision in our revised opex forecast.

The AER's reasoning for not approving this step change states that it does not consider there to be a change in regulatory reporting burden or material change in circumstances associated with the preparation and submission of the 2021-26 access arrangement proposal compared to that for the 2016-21 access arrangement proposal.[102] To be clear, our proposed step change was not related to a change in regulatory burden or material change in circumstances, but rather was based on actual and budget expenditure for the current access arrangement proposal, uplifted only for labour cost escalation.

As explained in section 7.2.2.2.2, our June 2015 opex forecast included a base year adjustment to remove these costs to be consistent with our proposed treatment of the ECM carryover amount calculation. Because these costs were removed from opex in the base year, we proposed a step change for costs in the final three years of the access arrangement period.

[102] AER 2015, *Draft Decision, ActewAGL Distribution Access Arrangement, 2016-21 – Attachment 7 – Operating Expenditure,* p7-33

Because we have accepted the AER's draft decision on the calculation of ECM carryover amounts as explained in section 7.2.2, we have not excluded these costs from base year opex in our revised proposal. Nonetheless, we maintain that a step change is required to compensate us for our efficient opex associated with the preparation and submission of access arrangement revision proposals for the period expected to commence in 2021. This is because, in circumstances where our access arrangement revision costs incurred in the 2014/15 base year are retained in actual opex used to calculate the incremental efficiency loss for 2014/15 under the ECM, the retention of those access arrangement revision costs in base opex for forecasting purposes suffices only to ensure that that loss is shared between ActewAGL Distribution and consumers on a 30:70 basis. Any compensation for the costs associated with the access arrangement revisions for the period expected to commence on 1 July 2021 must be effected by means of an opex step change. This is explained in the Efficiency carryover mechanism report by HoustonKemp, provided at appendix 9.01.

The AER's approach of including 20 per cent of our access arrangement revision project costs in forecast opex for each regulatory year of 2016-21 understates our efficient access arrangement revision costs for that period. The draft decision approach of forecasting that the cost of preparing access arrangement revisions for each year of the period expected to commence in 2021 will be equal to 20 per cent of the access arrangement revision project costs incurred in 2014/15 appears to be based upon an assumption that the entire cost of the access arrangement revision project for 2016-21 was incurred in 2014/15. If so, that assumption is incorrect. The costs associated with the preparation of our regulatory proposals span a number of years. In consequence, the actual cost of the preparation of our regulatory proposals is higher than the expenditure in any one financial year. The forecast reset associated opex costs for each of the years 2016/17 to 2020/21 set out in the draft decision, which, for each year, are equivalent to only 20 per cent of the 2014/15 financial year reset associated costs, are a significant underestimate of the costs likely to be associated with the access arrangement revision project for the period expected to commence in 2021.

Because our forecast for this step change is based on actual and budgeted costs for the current access arrangement revision project, as with base year opex, we have adjusted the forecast to be consistent with our actual 2014/15 costs and revised budget for 2015/16. This has resulted in a revised forecast of $4.0 million ($2015/16) for this step change. The increase in actual and revised budget costs for the current project are a result of the extremely limited timeframe in which to respond to the draft decision, which has meant the need to engage additional external resources to meet this tight timeframe, as well as the volume and detail of information requests received following submission of our June 2015 submission. We have no reason to expect that the circumstances in which we will be required to prepare our access arrangement revisions for the period expected to commence in 2021 will be any different.

We note that this material step change is required for ActewAGL Distribution to meet its obligations under clause 52 of the Rules, which requires us to submit an access arrangement revision proposal to the AER. As this forecast has been based on actual and budget expenditure for the current access arrangement revision proposal, it reflects the best estimate possible and has been arrived at on a reasonable basis.

7.4.2.5 New step change – RSA tariff reassignment

We have identified the need to introduce an additional step change as a result of likely new obligations regarding tariff reassignment, which will arise if the AER maintains its draft decision to approve the tariff assignment provisions in the 2016-21 access arrangement.[103] These changes were proposed to allow consumers to benefit by applying downward pressure on ActewAGL Distribution's network charges over time by encouraging new customers to connect to the network and stay connected to the network, and 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).

This step change was not identified at the time of the June 2015 submission proposal because we had assumed that Jemena's system, SAP, could facilitate bulk customer transfers. Further assessment by Jemena has identified that this is not the case.

Step change driver

This step change is necessary to enable customers and retailers to transition from our old tariff structure under our current GTA to a new, more efficient RSA tariff structure. We have proposed and, in its draft decision, the AER has accepted a more granular tariff structure for the volume market to replace the existing structure.

In moving from the old tariff structure to the new, we will need to be in a position to reassign up to an estimated 46,000 customers in 2016/17 as existing customers (or retailers on their behalf) choose the tariff that best meets their situation.

We estimate that customers switching to the heating tariff (VRH) will benefit by approximately $21 per annum on average or $105 for the full access arrangement period. There are 36,800 such customers on ActewAGL Distribution's network, which equates to customer benefits of approximately $3.9 million for these customers alone.

In proposing the new tariff structures, we assumed that tariff re-assignment from the old to the new tariff structures could be performed by Jemena's new OneSAP system. As outlined in the ITAUF step change Jemena is currently in the process of moving from its GASS+ system to its OneSAP system which includes making large-scale changes. At the time of the original proposal, the full scope of those changes was unclear. In November it become clear that, given the scope and timing of the project, the new OneSAP system will not provide for automatic tariff reassignments for *existing* customers in the near term (tariff assignments for new customers will be done automatically).

As a result, in order to implement the change from the old tariff structure to the new, JAM will need to manually process reassignment requests from existing customers and their retailers on ActewAGL Distribution's behalf under the DAMS agreement.

[103] Australian Energy Regulator, 2015, *Draft Decision, ActewAGL Distribution Access Arrangement, 2016-21,* p10-6

Manual reassignments will require additional staff, primarily in the first year of the new regulatory period. Without these additional resources, JAM will not be able to action requested tariff reassignments for existing customers in a timely way. This would delay or negate the benefits to customers of switching to a more suitable tariff. Impacted opex activities

The activity impacted by this step change is that of manually reassigning tariffs to existing customers on request from retailers or customers. Typically, we would expect approximately 800 ongoing tariff reassignments per year. The change from the GTA tariffs to the RSA tariffs is forecast to generate approximately 46,000 requests for tariff reassignment in the first year of operation of the RSA and then reduce to the ongoing rate. This estimate is based on mapping of tariffs that was the basis of our proposal to introduce the RSA tariff structure.

Prudence assessment

We have considered the following options:

Option 1: Do nothing (approximate net benefit -$3.9 million or less)

Benefits: Nil

Cost: Not implementing the new tariff structure, which would forgo customer benefits of at least $3.9 million

Option 2: **Alter SAP project scope to build automated re-assignment solution (approximate net benefit +$1.9 million)**

Benefits: Customer benefits of at least $3.9 million.

Cost: In the order of $2 million for additional IT works to design, program, test and implement the necessary changes to SAP. This also materially increases risk of late delivery of the SAP project as a whole.

Option 3: Temporarily boost manual processing of tariff reassignments (recommended, approximate net benefit +$3.2 million or more)

Benefits: Customer benefits of at least $3.9 million.

Cost: $770,000 over the 2016-21 access arrangement period (see forecast below).

Option 3 has the highest net benefit of the three options and is therefore the preferred option.

Opex step change forecast

The opex step change is forecast with the following assumptions:

First year - 2016/17

- Six FTEs to process approximately 46,000 reassignments in 2016/17 at an estimated time of 15 minutes to process one reassignment.
- Retailers and customers request reassignments throughout the first year and the workload is evenly spread. If the assumption is wrong, and retailers concentrate on seeking reassignments (say) in the first half of the year, twice as many staff would be required for those first six months. However, those staff would then not be required in

the second half of the year, and therefore total cost would remain unchanged. JAM will need to make sure that resourcing is flexible to ramp up or down depending on the pace of retailer requests to avoid back logs or over-resourcing.

Subsequent years – 2017/18 to 2020/21

- 0.11 FTE to process approximately 800 reassignments per year, based on an estimate of 15 minutes per reassignment.

Table 7.6 RSA Tariff Reassignment forecast summary ($million, 2015/16)

Step change component	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
FTEs - Service desk tariff officer	0.00	0.72	0.01	0.01	0.01	0.01	0.77
Total	**0.00**	**0.72**	**0.01**	**0.01**	**0.01**	**0.01**	**0.77**

7.4.2.6 New step change – tariff variation notice gas quantities

In our June 2015 submission we made a revision requiring annual tariff variation notices to include a statement to support the gas quantity inputs (refer to chapter 13). This was part of the changes we made to reflect the AER's new regulatory requirement, in a manner that promotes consistency with JGN's access arrangement. The AER accepted this change in its draft decision (refer to section 11.4 of attachment 11 of the draft decision). As a result, we will incur additional costs to meet this new requirement that were not included in our initial opex forecast, and so have included a new step change in our revised opex forecast. The associated costs are not captured in base year opex or the rate of change.

We have based our proposed step change on that proposed by JGN in its revised proposal[104] and accepted by the AER in its final decision.[105]

JGN's forecast was based on an estimated quote from KPMG for annual independent audit of supporting gas quantity inputs to ensure compliance with the tariff variation process specified in the access arrangement. KPMG estimated an annual cost of $0.03 million. No costs were included in the final year of the access arrangement period as there is no tariff variation notice in this year.

ActewAGL Distribution has adopted this estimate for its opex forecast, as shown in Table 7.9 below.

[104] JGN 2015, *2015-20 Access Arrangement - Response to the AER's draft decision and revised proposal - Appendix 5.4 - Operating expenditure step changes report,* p.1

[105] Australian Energy Regulator 2015, *Final decision, Jemena Gas Networks Access Arrangement, 2015-20, Attachment 7 – operating expenditure,* p7-24

Table 7.7 Tariff variation notice gas quantities step change forecast summary ($million, 2015/16)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Tariff variation notice gas quantities	0.00	0.03	0.03	0.03	0.03	0.00	0.14
Total	**0.00**	**0.03**	**0.03**	**0.03**	**0.03**	**0.00**	**0.14**

7.5 Category specific forecasts

7.5.1 AER draft decision

The AER's draft decision accepted our proposal to use category specific forecasts for UNFT, EIL and UAG costs, but did not accept the category specific forecasts for insurance, water bath heater operations and ancillary services costs. Instead, the AER has retained these costs in the opex base to be forecasting using the base-step-trend approach.

7.5.2 Response to draft decision and revised proposal

We accept the AER's draft decision on category specific forecasts. With regard to insurance, water bath heater operations, and ancillary services, we note that our category specific forecasts for these categories were not materially different to our expenditure in the base year.

As noted in section 7.2.2.3, our acceptance of ancillary services opex being included in base opex is on the basis that our proposed ancillary services charges are accepted. As these charges have been based on a cost build-up of these services, if these charges are not accepted by the AER in its final decision ActewAGL Distribution will not be provided with an opportunity to recover its efficient costs. Should the AER not accept these charges, we remain of the view that these costs are better forecast using a category specific forecast to ensure we can recover at least our efficient costs.

We have updated our forecasts of the UNFT, EIL and UAG to reflect the best available estimates at the time of providing our revised opex forecast. Our forecasts for these costs are provided in Table 7.8 below.

Table 7.8 Revised category specific forecasts ($million, 2015/16)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total 2016/17 – 2020/21
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 category specific forecasts	**8.1**	**8.3**	**8.6**	**8.8**	**9.1**	**8.9**	**43.7**

7.6 Revised opex forecast

Our resulting revised opex forecast for the 2016-21 access arrangement period is $162.9 million ($2015/16), which is 13 per cent higher than our initial opex forecast. Annual forecasts are provided in Table 7.9 below. Our revised opex forecast (excluding debt raising costs) is also provided in detail in our revised opex model, provided at appendix 7.01

Table 7.9 Revised opex forecast 2015/16 – 2020/21 ($million, 2015/16)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total 2016/17 – 2020/21
Base opex	21.4	21.4	21.4	21.4	21.4	21.4	**107.2**
Real price growth	0.0	0.1	0.1	0.2	0.3	0.5	**1.2**
Output growth	0.1	0.3	0.4	0.6	0.8	1.0	**3.1**
Productivity growth	0.1	0.1	0.2	0.3	0.3	0.4	**1.3**
Step changes	(0.0)	1.2	0.3	0.2	2.9	1.7	**6.3**
Category specific forecasts	8.1	8.3	8.6	8.8	9.1	8.9	**43.7**
Total	**29.7**	**31.4**	**31.0**	**31.6**	**35.0**	**34.0**	**162.9**

8 Corporate income tax

8.1 AER's draft decision

The AER has approved ActewAGL Distribution's proposed approach for: calculating its forecast income tax allowance via the post-tax revenue model; rolling forward the tax asset base (TAB) via the roll forward model; standard tax asset lives; and calculating the remaining asset lives via the weighted average method.

The AER has not accepted our proposed opening TAB value of $254.1 million ($nominal) as at 1 July 2016 nor our proposed corporate income tax allowance of $15.0 million ($nominal) over the 2016-21 period.

The AER's draft decision is that there has been an interval of delay in 2015/16. As a result, the AER's draft decision rolls forward ActewAGL Distribution's TAB to 1 July 2015 at a value of $231.9 million (nominal) and provides an income tax allowance of $17.1 million (nominal) for the periods 2015/16 and 2016-21. The AER's draft decision on the income tax allowance is premised on its other decisions on gamma (chapter 5 refers); the rate of return (chapter 5 refers), forecast capex (chapter 6 refers) and forecast opex (chapter 7 refers).

As part of its draft decision the AER has created an additional 'land and easement' asset class to capture ActewAGL Distribution's forecast land capex for 2016-21. This 'land and easement' asset class will not be depreciable for tax purposes. The AER has also amended ActewAGL Distribution's roll forward model to better capture the impact on remaining asset lives of the actual capex from 2009/10.

8.2 ActewAGL Distribution's response and revisions

We do not accept the AER's draft decision on the income tax allowance to be included in our revenue requirement and our revised proposal includes a revised proposed tax allowance. This is mainly due to our position on gamma, as detailed in chapter 5.

We accept the AER's creation of a 'land and easement' asset class and the modifications to the roll forward model. ActewAGL Distribution has applied this revised model for determining the roll forward of its TAB after also updating the model to include actual capex for 2014/15.

Chapters 5 (rate of return and gamma), 6 (forecast capex) and 7 (forecast opex) cover ActewAGL Distribution's response to the AER's other decisions which impact the determination of the income tax allowance.

As detailed in section 2.6, for our revised proposal we have accepted that a true-up will occur for 2015/16. As such, we have determined a revised proposed income tax allowance based on a roll forward of the TAB from 1 July 2015, with an opening TAB of $231.4 million (nominal). This variance with the AER's opening TAB is due to updated actual 2014/15 capex. Our revised proposal includes a revised tax allowance of $20.0 million ($nominal).

9 Efficiency carryover mechanism

9.1 Carryover amounts from the 2010-15 period

9.1.1 ActewAGL Distribution's June 2015 proposal

In our June 2015 proposal, we proposed that a total carryover amount of $11.1 million ($2015/16) arising from the operation of the efficiency carryover mechanism (ECM) in the 2010–15 access arrangement period be added to the revenue building blocks for the 2016–21 access arrangement period.

We made that calculation in the context of our June 2015 proposal that the ECM would be closed out in 2014/15 and restarted in 2016/17 with the consequence that a zero incremental efficiency gain (loss) would be ascribed to the 2014/15 base year under the ECM.

9.1.2 The AER's draft decision

The draft decision proposed an alternative approach to the ECM under which that incentive mechanism is not closed out but continues to operate, and a non-zero incremental efficiency loss is ascribed to the 2014/15 base year under that ECM.

On the basis of this alternative approach, the AER considered that ActewAGL Distribution should receive a carryover amount of $1.4 million ($2015/16) in the 2016–21 period from the application of the ECM during the 2010–15 period. The AER also included a carryover amount of $1.5 million in the revenue building blocks for 2015/16. Accordingly, the total carryover amount included in the revenue building blocks was $2.9 million.

9.1.3 ActewAGL Distribution's response to draft decision

We accept the approach to the application of the ECM in the previous period set out in the draft decision and acknowledge a benefit of that approach is that the ECM operates in a continuous manner (as is generally intended for efficiency carryover mechanisms, including the AER's Efficiency Benefit Sharing Scheme for electricity network service providers[106]).

In accordance with the rolling carryover mechanism in clause 4.6 of the 2010-15 access arrangement and the AER's draft decision on the formulae to be applied for the calculation of carryover amounts in 2014/15 and 2015/16, we have calculated the carryover amounts as shown in Table 9.2 below. The carryover amounts for each year of the 2016-21 access arrangement period, as shown in Table 9.2, have been added to the revenue building blocks for that year.

[106] AER 2013, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November.

Table 9.1 Carryover amounts from 2010-15 period

$ million	2010/11	2011/12	2012/13	2013/14	2014/15
Forecast opex for the incentive mechanism, $2009/10	15.9	18.0	18.6	18.6	18.0
Forecast opex for the incentive mechanism, $2015/16	18.4	20.9	21.6	21.6	20.9
Total actual opex, $2015/16	26.6	28.4	27.6	26.1	28.6
Excluded costs, $2015/16	6.0	8.4	7.9	8.4	7.3
Opex subject to the incentive mechanism, $2015/16	20.6	20.0	19.8	17.8	21.2
Incremental gain/loss ($2015/16)	-2.2	3.0	1.0	2.0	-4.2

Table 9.2 Carryover amounts for 2015/16 – 2020/21 ($million, 2015/16)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Carryover amount	-0.4	1.8	-1.2	-2.2	-4.2	0.0	**-6.2**

While we have adopted the AER's approach to calculating the carryover amounts from 2010-15, our values are different to those calculated by the AER (as shown in the draft decision[107]) because we have identified and corrected an error in the AER's calculation. Correcting the AER's error in the treatment of the cost pass through amount in 2014/15 results in a $4 million lower total carryover amount for the 2015/16 – 2020/21 period. We have also updated the 2014/15 values with actual amounts. Our revised ECM calculations are provided in appendix 9.02 to this Response.

Finally, our acceptance of the AER's approach to calculating the ECM carryover amount is on the expectation that the AER will correct, via the opex allowance, the excessive penalties imposed on ActewAGL Distribution through the combined operation of the AER's draft decisions on the application of the ECM and the base opex. Our response to the AER's draft decision and our revised proposal are set out in detail in the opex chapter of this Response, and in the expert report submitted as appendix 9.01.

[107] AER 2015, *Attachment 9: Efficiency carryover mechanism| Draft decision, ActewAGL Distribution access arrangement 2016-21*, Table 9-3, November, p. 9-13

9.2 ECM applicable during the 2016-21 period

9.2.1 ActewAGL Distribution's June 2015 proposal

In our June 2015 proposal, we proposed an ECM to apply to the 2016–21 access arrangement period which was based largely on the AER's electricity network Efficiency Benefit Sharing Scheme, albeit with certain exclusions and adjustments. In particular, we:

- proposed a formula for calculating the incremental efficiency gain or loss in the 2016/17 financial year that assumed the ECM would be closed out in 2014/15 and restarted in 2016/17; and
- proposed the inclusion of a clause to address the application of the ECM in the event that an interval of delay occurs at the end of the 2016-21 period.

9.2.2 The AER's draft decision

The AER's draft decision largely accepted the ECM proposed in our June 2015 submission, but required changes to certain features including that:

- consistent with the AER's approach of not closing out the ECM in the 2014/15 financial year and calculating a non-zero incremental efficiency loss for that year, the formula for calculating the efficiency gain or loss in the 2016/17 financial year (the first year) should be the same as the formula for the second, third and fourth years of the regulatory period;
- the clause addressing the application of the ECM in the event an interval of delay occurs at the end of the 2016-21 period should be deleted as intervals of delay are dealt with by the National Gas Rules;
- certain of the adjustments and exclusions from the application of the ECM proposed by ActewAGL Distribution should be deleted; and
- the ECM should not be a fixed principle for the 2026-31 period.

9.2.3 ActewAGL Distribution's response to draft decision

We have largely accepted the revisions required by the AER. In particular, we have:

- in accordance with the draft decision, accepted the change to the formula for calculating the incremental efficiency gain or loss in the 2016/17 financial year (the first year of the 2016-21 period);
- in accordance with the draft decision, deleted the clause addressing the application of the ECM in the event of an interval of delay;
- accepted the AER's proposed amendments to the ECM adjustments and exclusions (other than those discussed below); and
- in accordance with the draft decision, altered clause 3 of the access arrangement and the fixed principle to make clear that the fixed principle does not operate to require the

application of the ECM established in the access arrangement in the 2021-26 period but rather requires only that the total revenue for the 2021-26 period reflect the carry forward of the incremental efficiency gains (losses) arising under that ECM in the 2016-21 period.

In its draft decision, the AER proposed the amendment of the access arrangement to remove:

- provision for adjustment of the forecast opex used to calculate carryover amounts under the ECM to take account of any difference between actual and forecast connections;
- the exclusion of debt raising costs from the application of the ECM; and
- the exclusion of uncontrollable costs from the application of the ECM.

In our revised access arrangement, we have retained provision for adjustment of forecast opex to take into account any difference between actual and forecast connections. We maintain our position, as set out in our June 2015 submission. If the adjustment for differences between forecast and actual connections is not retained in the 2016-21 access arrangement, ActewAGL Distribution will be penalised when connections exceed the forecast (to the extent that this results in higher than forecast opex), and rewarded for situations where demand falls below the forecast. This will be inconsistent with the revenue and pricing principles in the NGL. We also re-iterate that we disagree with the AER's comment that the adjustment would be unnecessarily complex. A continuation of the treatment which has applied for 2010-15 would involve low administrative costs, which will be more than offset by the benefits of having an incentive scheme which provides incentives for properly measured efficiency gains.

In addition, while we have removed the general exclusion of non-controllable costs from the application of the ECM, we have replaced this with specific exclusions for UAG, licence and carbon costs, and relevant taxes, and the conferral on the AER of discretion to exclude other specific uncontrollable costs incurred and reported by ActewAGL Distribution during the 2016-21 period. We anticipate that this approach will be acceptable to the AER, as the JGN access arrangement for 2015-20 recently approved by the AER contained analogous exclusions. We have also retained the specific exclusion for debt raising costs, noting that this exclusion has been approved by the AER in the JGN access arrangement.[108]

[108] AER 2015, *Final decision Jemena Gas Networks access arrangement, Approved access arrangement*, June, p. 33

10 Revenue requirement and price path

10.1 AER draft decision

10.1.1 Revenues

The AER's draft decision did not accept our proposed forecast smoothed revenue requirement for the 2016-21 access arrangement period of $358.4 million ($nominal). Instead the draft decision included forecast smoothed revenue of $279.1 million ($nominal), which is 20 per cent lower than our proposal.

As discussed in section 2.6, the AER's draft decision includes a reconciliation or 'true up' of revenue for 2015/16, because it took the position that an internal of delay occurred between the revision commencement date in ActewAGL Distribution's current access arrangement and the actual date on which revisions will take effect. The result of this was a true-up of $18.3 million, being the difference between forecast 2015/16 actual revenues and the AER's building block assessment of revenues required in 2015/16. This amount is to be returned to customers over the 2016-21 access arrangement period.

10.1.2 Price path

The AER's draft decision revenue requirement resulted in a price path of a 25.68 per cent real decrease in weighted average tariffs in 2016/17, followed by real increases of one per cent for each subsequent year of the period.

10.2 ActewAGL Distribution's response and revisions

10.2.1 Revenues

We do not accept the AER's draft decision on our revenue requirement as it is does not allow ActewAGL Distribution a reasonable opportunity to recover at least its efficient costs of providing pipeline services and meeting its relevant obligations (as required by the revenue and pricing principles in the NGL).

ActewAGL Distribution's revised total annual pipeline service building block revenue requirement for the 2016-21 access arrangement period and resulting smoothed revenue requirement and X-factors are set out in Table 10.1 below.

Our revised proposed unsmoothed revenue for the 2016-21 access arrangement period is 8.7 per cent higher than our initial proposal. This is mainly driven by our revised proposed WACC of 8.586 per cent, compared to 7.15 per cent included in our initial proposal.

Table 10.1 ActewAGL Distribution total revenue, 2015/16-2020/21 ($million, nominal)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Return on capital	29.2	31.3	32.6	33.8	35.0	36.3	**198.2**
Return of capital (depreciation)	4.4	5.4	6.2	7.0	7.9	8.8	**39.6**
Operating expenditure	29.9	32.3	32.6	33.9	38.4	38.1	**205.1**
Revenue adjustments	-0.4	1.8	-1.3	-2.4	-4.6	0.0	**-6.8**
Corporate income tax	2.2	2.6	3.3	3.8	4.0	4.1	**20.0**
Total revenue (unsmoothed)	65.4	73.5	73.4	76.1	80.7	87.3	**456.2**
Total revenue (smoothed)	**70.4**	**74.4**	**75.3**	**76.4**	**77.6**	**79.0**	**453.0**
X-factor	2.14%	-3.78%	0.00%	0.00%	0.00%	0.00%	N/A
Forecast inflation	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	N/A
Nominal price change	0.00%	6.05%	2.19%	2.19%	2.19%	2.19%	N/A

As explained in section 2.6, for our revised proposal we have accepted the AER's position that a revenue true-up will apply for 2015/16. As such, the smoothed revenues and X factors for the 2016-21 access arrangement period in Table 10.1 above include a revenue reconciliation or 'true up' of revenue for 2015/16 of $5.0 million. This is the difference between our estimate of revenue to be recovered in 2015/16 and our forecast building block revenue requirement. This has been calculated using an approach consistent with that proposed in our initial proposal and adopted by the AER in its draft decision,[109] which uses the PTRM to calculate the building block revenue requirement and smoothing of these revenues across the access arrangement period. For this purpose, the building blocks proposed are consistent with our proposal for the 2016-21 access arrangement period. A nominal vanilla WACC of 8.64 per cent has been applied in 2015/16, which is based on a placeholder averaging period for the return on equity risk free rate of the last 20 business days in September 2015 and ActewAGL Distribution's actual return on debt averaging period for the 2015/16 year (accepted by the AER in its Draft Decision) of the 15 business days commencing on 4 June 2015. Details of this rate of return estimate are provided in section 5 and appendix 5.01. Details of our other proposed building blocks for 2015/16 are provided in their respective sections.

[109] AER 2015, *Overview | Draft decision, ActewAGL Distribution access arrangement 2016-21*, November, pp.20-22

10.2.2 Price path

Our revised proposal includes a revised price path of a 3.78 per cent real increase in weighted average tariffs in 2016/17, followed by CPI only increases for each subsequent year of the period. In developing our revised price path and tariff schedule we have applied the same principles that we applied in developing the June 2015 proposal. These principles take account of the feedback we have received from consumers, particularly through the ECRC, and also the requirements of the Rules and the NGL.

Our proposed price path is consistent with the preference of consumers for a stable price path with limited shocks. In contrast, the AER's draft decision price path involves a larger 2016/17 price adjustment, followed by increases above the CPI for the remaining four years.

While the AER's draft decision involves an average price reduction in 2016/17, and our revised proposal involves an increase, we do not consider the AER's draft decision to be in consumers' long term interests. As we noted in our June 2015 submission, achieving the NGO requires sustainable prices and the maintenance or enhancement of quality, safety, reliability and security over the long term. Short-term price reductions that cannot be sustained may result in outcomes that are contrary to consumers' long term interests. This has been recognised by the Australian Competition Tribunal (Tribunal):[110]

> *As noted at the outset, customers will benefit in the long run if resources are used efficiently, ie if investors receive a return on efficient investment which covers the opportunity cost of the capital required to deliver the services. While consumers might benefit today from the lowest possible prices which do not provide an adequate return on investment, such prices are not in their long term interests … If those prices were sustained, they would not generally support the allocation of sufficient resources including capital, to maintain and increase the supply of the affected service in accordance with the value the consumers place on it. This would be contrary to the promotion of efficient investment and the long term interests of consumers.*

We believe that the price path adopted by the AER is not sustainable and would result in outcomes contrary to the NGO.

10.2.3 Customer impacts

Table 10.2 sets out the estimated customer network bill impacts resulting from the revised proposal revenue requirements and demand forecasts. Network charges represent about a third of customers' total retail bill.

A key objective for our tariff strategy is to maintain and grow utilisation of the shared gas network because this will put downward pressure on average prices over time. We have also listened to our customers, who have expressed a preference for stable bills.

[110] *Re Application by ElectraNet Pty Limited (No 3)* [2008] ACompT 3, p. 251.

As a result, for small, medium and large (without heating) residential customers, the bill impacts are broadly in line with the overall weighted average price path – upfront bill increases (in real terms) in 2016/17, followed by stable bills (in real terms) in the subsequent years.

Key markets are our large residential customers with gas heating appliances, and business customers. For these groups, in real terms, we plan to keep bills effectively unchanged in 2016/17, followed by bill decreases in each of the final four years of the period. This strategy will support gas usage and new gas appliance installation, which is consistent with our objective of growing network utilisation to lower average prices.

Our major customers have told us that they value price stability. This helps them plan their investments and operations. We have proposed stable real price increases of 2.7 per cent for the final four years of the next period. We have balanced this approach against the need to recover a fair share of our total revenue requirement from this market segment. Taking this need into account, we have proposed a real price increase in 2016/17 for our major customers.

Table 10.2 Customer network bill impacts, 2015/16-2020/21

Customer type	Average consumption and tariff type	2015/16 current bill	Anticipated distribution bill change $ real				
			2016/17	2017/18	2018/19	2019/20	2020/21
Small Residential	15GJ VRI	$239	$18	$0	$0	$0	$0
Medium Residential	25GJ VRI	$319	$24	$0	$0	$0	$0
Large Residential without Heating	45GJ VRI	$478	$36	$0	$0	$0	$0
Large Residential with Heating	45GJ VRH	$478	$2	-$1	-$1	-$1	-$1
Very Large Residential with Heating	90GJ VRH	$836	-$2	-$3	-$3	-$3	-$3
Small Business	200GJ VBS	$1,732	-$18	-$6	-$7	-$6	-$6
Small Business	2,000GJ VBS	$15,926	-$225	-$62	-$65	-$62	-$63
Medium Business	8,000GJ VBM	$55,208	-$698	-$208	-$219	-$210	-$211
Small Major Customer	10,000GJ DBC	$73,775	$14,374	$2,424	$2,491	$2,559	$2,629

11 Reference tariff setting

11.1 Introduction

This chapter sets out ActewAGL Distribution's response to the Australian Energy Regulator's (AER's) draft decision on the proposed reference tariffs over the 2016-21 access arrangement period.

ActewAGL Distribution's June 2015 submission proposed improvements to the reference tariff classes and tariff structures over the 2016-21 access arrangement period, including:

- New tariff classes and tariff categories that respond to the changes occurring in the gas market;
- Tariff structures that encourage the efficient use of gas and growth of the gas network;
- A mechanism to enable us to introduce or withdraw reference tariffs via the annual tariff variation mechanism; and,
- A tariff assignment process to enable customers to respond to the proposed reference tariffs.

These improvements were designed to respond to the changes occurring in the gas market in a way that promotes the long term interests of our customers. We engaged extensively with customers and stakeholders to understand and respond to their priorities and preferences in proposing the reference tariffs.[111] The proposed changes to the reference tariffs are underpinned by the proposed change to a single haulage reference service (see Chapter 3 of this document).

ActewAGL Distribution's welcomes the AER's approach to assessing our proposed reference tariffs and its acceptance that the proposed structure of reference tariffs is compliant with the Rules.[112] This approach recognises that gas is a fuel of choice in the ACT, with this competition aligning our interests with those of our customers.

ActewAGL Distribution has not submitted further evidence on the elements of our reference tariff proposal that the AER has accepted in the draft decision. Should the AER receive any further evidence or submissions from stakeholders on any of these matters, we would appreciate the opportunity to review and respond in a timely manner.

[111] Details on our consumer engagement program, and the feedback we received, are provided in our *Access arrangement information, Attachment 2: Consumer engagement*, submitted to the AER in June 2015.

[112] AER 2015, *Attachment 10– Reference tariff setting, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 6.

11.2 AER's draft decision

The AER reviewed ActewAGL Distribution's proposed reference tariffs against the criteria set out in clauses 93 and 94 of the National Gas Rules (Rules), which require that:

- Reference tariff classes group customers together on an economically efficient basis, and avoid unnecessary transaction costs[113]
- Revenue from reference tariffs compares with the cost of providing each individual reference tariff (stand-alone and avoidable cost)[114]
- Reference tariff structures take into account the long run marginal cost for the reference service and consideration be given to whether customers are able or likely to respond to price signals.[115]

As outlined in Table 11.1, the AER has:

- Accepted ActewAGL Distribution's proposed reference tariff classes[116] and tariff structures[117], and indicated that it is satisfied that the proposed reference tariffs are consistent with the Rules;[118]
- Accepted ActewAGL Distribution's proposed mechanism to enable it to introduce or withdraw reference tariffs via the annual tariff variation mechanism; but
- Requested the level or quantum of the reference tariffs be amended to reflect the revised revenue allowance set out in its draft decision.[119]

With respect to ActewAGL Distribution's proposed tariff categories and tariff structures, the AER stated that:

> *"We accept ActewAGL's proposed new tariff structure. While it involves significant changes to the tariff structure in ActewAGL's current access arrangement, we note the new tariff structure is consistent with those applied by other gas distribution networks in recent years. We also consider it is compliant with the requirements of the NGR.*

[113] Rule 94(2)

[114] Rule 94(3)

[115] Rule 94(4)

[116] AER 2015, *Attachment 10– Reference tariff setting, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 16.

[117] AER 2015, *Attachment 10– Reference tariff setting, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 6.

[118] For example, the draft decision notes that the proposed reference tariffs are consistent with the cost of providing each individual reference tariff, use well-accepted LRMC methodologies and have been determined with regards to customers' ability to respond to price signals. AER 2015, *Attachment 10– Reference tariff setting, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 17-18.

[119] AER 2015, *Attachment 10– Reference tariff setting, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 6.

A number of submissions were concerned about ActewAGL's proposed new tariff structure. However, we found no compelling evidence in submissions that would lead us to not accept ActewAGL's proposed tariff structure." [120]

The AER draft decision on ActewAGL Distribution's reference tariffs is summarised in Table 11.1 below.

Table 11.1 AER draft decision on ActewAGL Distribution's proposed reference tariffs

Aspect of proposed reference tariffs	AER draft decision	AER comment
Tariff classes and categories		
Tariff categories and classes	Accept AAD proposal	Consistent with NGR 94(1)-(2)
Tariff assignment process	Accept AAD proposal	Customers will not be discriminated against because they have choice about assignment to a multi-appliance tariff category
Ability to add, vary or remove tariffs	Accept AAD proposal	Using the annual tariff mechanism is administratively simpler and more efficient for network operators and customers, than reopening an access arrangement
Tariff Structures		
Tariff structures	Accept AAD proposal	Consistent with NGR 93 and 94. Proposed tariff structure allows a more cost reflective approach to tariffs. This is an efficient outcome.
Tariffs take into account LRMC of providing services	Accept AAD proposal	The approach taken is generally consistent with that applied by other gas distribution networks and has historical precedent in pas access arrangements
Tariff Levels		
Allocation of revenues and costs to reference tariffs	Accept AAD proposal	Consistent with NGR 93(1) – (2)
Tariff classes and revenue limits	Accept AAD proposal	Consistent with NGR 94(3)
Quantum of reference tariffs	Reject AAD proposal	The quantum of the proposed reference tariffs must be amended to reflect the revised revenue allowance set out in the AER draft decision

[120] AER 2015, *Attachment 10– Reference tariff setting, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 10.

11.3 ActewAGL Distribution's response

The improvements ActewAGL Distribution proposed to the reference tariff structure over the 2016-21 access arrangement period were designed to respond to the changes occurring in the gas market in a way that promotes the long term interests of our customers. We engaged extensively with customers and stakeholders to understand and respond to their priorities and preferences in proposing the reference tariffs. The changes to the reference tariffs are underpinned by the proposed change to a single haulage reference service, which the AER has accepted in the draft decision (see chapter 3 of this *Response*).

ActewAGL Distribution welcomes the AER's approach to assessing our proposed reference tariffs and its acceptance that the proposed structure of reference tariffs is compliant with the Rules.[121]

In our view, this approach recognises that the competitive tension resulting from gas being a fuel of choice in the ACT aligns our interests with those of our customers. This ensures that we will respond to the changes occurring in the gas market in a way that promotes the long term interests of our customers.

However we recognise that the AER:

- Notes the concerns of stakeholders regarding the complexity of the proposed tariff structure, yet recognises that the proposed reference tariff structures allows a more cost reflective approach to tariffs which is an efficient outcome.[122]
- Encourages ActewAGL Distribution to include further information in its revised access arrangement relating to the proposed tariff structure, including the declining block structure that ActewAGL Distribution is proposing to maintain.[123]
- Encourages ActewAGL Distribution to work with retailers to establish an administratively simple and cost effective process for demonstrating a customer's qualification for these tariffs.[124]

Our response to the AER's draft decision is summarised in Table 11.2 and is to:

- Accept all aspects of the AER draft decision.
- Note the issues raised by stakeholders in the AER's draft decision (recognising that some of the requested information was provided in the ActewAGL Distribution's Tariff Structures Statement[125]).

[121] AER 2015, *Attachment 10– Reference tariff setting, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 6.

[122] AER 2015, *Attachment 10– Reference tariff setting, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p.11.

[123] AER 2015, *Attachment 10– Reference tariff setting, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 13.

[124] AER 2015, *Attachment 10– Reference tariff setting, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 14.

- Engage further with stakeholders, including retailers and community groups, and provide further information in the updated Tariff Structures Statement on the process for assigning customers to tariffs categories and the benefits of the proposed tariff structures[126].
- Update the quantum of the proposed reference tariffs to reflect the revenue allowance in our revised proposal (See chapter 10 of this document).

Table 11.2 Summary of ActewAGL Distribution's response to the AER draft decision on reference tariffs

Aspect of proposed reference tariffs	AER Draft Decision	AAD response	AAD comment
Tariff classes and categories			
Tariff categories and classes	Accept AAD proposal	Accept draft decision	AAD recognises that the proposed tariffs are more complex, yet as AER notes, it will allow a more cost reflective approach to tariffs which is an efficient outcome. AAD will update the Tariff Structures Statement to assist stakeholders understand the new proposed tariff classes and categories. AAD also intends to engage further with consumers, through its Energy Consumer Reference Council (ECRC) and wider consumer engagement program.
Tariff assignment process	Accept AAD proposal	Accept draft decision	AAD is committed to working with retailers to establish a simple process for assignment to other tariffs categories and have initiated a process for engaging with retailers to identify and issues or concerns
Ability to add, vary or remove tariffs	Accept AAD proposal	Accept draft decision	AAD recognises that introducing or withdrawing reference tariffs as part of the annual tariff mechanism requires AER approval prior to changes coming into effect.
Tariff Structures			
Tariff structures	Accept AAD proposal	Accept draft decision	AAD recognises that some stakeholders such as the North Canberra Community Council raised concerns about the pricing objectives of the proposed tariff structures. However we agree with the AER that a more simple tariff structure (involving a flat $/GJ tariff) would not send efficient

125 For example, Section 8.1.1 of the Tariff Structures Statement explains how fixed charges are set. *ActewAGL Distribution - Access Arrangement Information: Appendix 12 01 Tariff Structure Statement* - July 2015.

126 Including in relation to how the size of the blocks, associated price levels and fixed charge price levels were determined.

			price signals with potential for cross-subsidisation between customers. AAD will engage further with stakeholders and provide more information (including in relation to how the size of the blocks, associated price levels and fixed charge price levels were determined) in its updated Tariff Structures Statement. AAD also intends to engage further with consumers, through its Energy Consumer Reference Council (ECRC) and wider consumer engagement program.
Tariffs take into account LRMC of providing services	Accept AAD proposal	Accept draft decision	No further comment
Tariff Levels			
Allocation of revenues and costs to reference tariffs	Accept AAD proposal	Accept draft decision	No further comment
Tariff classes and revenue limits	Accept AAD proposal	Accept draft decision	No further comment
Quantum of reference tariffs	Reject AAD proposal	Reject draft decision	The quantum of the proposed reference tariffs reflects the revenue allowance in AAD's revised proposal (See chapter 10)

.

12 Reference tariff variation mechanism

ActewAGL Distribution's proposed 2016-21 access arrangement includes a reference tariff variation mechanism, which comprises the mechanisms and processes for varying reference tariffs during the access arrangement period.

Our June 2015 submission included several proposed changes to the reference tariff variation mechanism in the 2010-15 access arrangement, including:

- Replace the fixed schedule of tariffs with a weighted average price cap (WAPC). This is designed to provide ActewAGL Distribution with incentives aligned with the long term interests of customers and flexibility to respond to changes in the gas market, including changing consumption patterns, during the access arrangement period.
- Refresh the cost pass through events, largely to reflect regulatory developments since the approval of the 2010-15 access arrangement. This includes removing unnecessary events, updating definitions to improve clarity and certainty and adding new events.
- Streamline the process for adjusting tariffs due to changes in specified uncontrollable costs. Instead of the cost pass through mechanism, ActewAGL Distribution proposed to use a symmetrical automatic adjustment factor in the reference tariff variation formula.
- Align the tariff variation process with other access arrangements and the National Electricity Rules (NER).

The proposed reference tariff variation mechanism promotes the National Gas Objective (NGO) by:

- Providing incentives for ActewAGL Distribution to increase volumes and improve utilisation, which reduces costs per customer and ultimately the prices consumers face;
- Providing a clear mechanism for ActewAGL Distribution to fully recover its efficient costs (including those that are unexpected and uncontrollable); and
- Reducing the administrative burden associated with annual tariff adjustments, which will reduce costs and prices.

12.1 AER's draft decision

In the draft decision the AER has accepted ActewAGL Distribution's proposal to transition to a weighted average price cap (WAPC) from a schedule of fixed prices. The AER has also accepted the proposed automatic adjustment factor (within the WAPC formula), noting that the adjustment factors are consistent with those it has approved for other gas distribution networks.[127]

[127] AER 2015, Draft Decision, Attachment 11, p 11-15

However, the AER has:

- not accepted the definitions for certain parameters within the WAPC formula;
- not accepted our proposed side constraint on annual tariff changes;
- not accepted our proposal to vary reference tariffs during a financial year to apply at a date prior to the start of the next financial year;
- not accepted the proposed fixed principle in relation to inter-period cost pass through events; and,
- not accepted all of our proposed cost pass through events. Specifically:
    - The AER requires amendments to the definitions of the regulatory change event, service standard event, insurance cap event, insurer credit risk event, terrorism event, natural disaster event and network user failure event.
    - The AER also requires the deletion of the proposed short term trading market event, supply curtailment event and general pass through event from the access arrangement in our June 2015 Submission.

12.2 ActewAGL Distribution's response and revisions

Our responses to each of the AER's required revisions (as set out in *Attachment 11: Reference tariff variation mechanism* of the draft decision) are summarised in Table 12.1 below. Where we have not adopted the AER's revisions, further explanation is provided in the following sections.

While we have worked through each of the AER's proposed revisions we note that the AER has not provided any mark up or itemised list of changes. The AER has also not provided any explanation for many of the changes made, instead just providing blocks of text to replace sections of our proposed mechanism. This has made it difficult to fully respond and address the AER's concerns and ultimately ensure that the access arrangement meets the long term interests of consumers. Nevertheless we have worked through the changes in the limited time made available by the AER and responded to all revisions we have identified.

In the case that our revised proposal had not addressed a specific revision, if we have mistaken the rationale behind the change or if the AER has any other concerns we would like to re-extend our offer to meet with the AER to discuss and resolve any issues.

In working through AER's the proposed revisions changes we have found that our proposed access arrangement (which we carefully prepared in the long term interests of consumers) already had, in many cases, features which addressed what we presume were the AER's concerns. We consider that a more open dialogue between with the AER could avoid needless revisions, lower administrative costs and ultimately lower costs for consumers. We look forward to adopting a more collaborative approach in the lead up the AER's final decision.

Table 12.1 Reference tariff variation mechanism – summary of responses to draft decision

Element (Required revision*)	Draft decision	AAD response
Annual tariff variation formula (11-1)	**Amend** to be consistent with : Figure 11.1 such that: 1. The notation of indices is changed 2. Clarifies that if the ABS ceases to publish specified CPI, AER will decide on replacement. 3. Changes the definition of q_t to include “audited” sales quantities. 4. Definition of p_{t-1} no longer includes reference to scaling in AA clause 7.24 (ie how to set prices when the TVN is not submitted or rejected).	 1. **Reject.** The notation proposed is consistent and unambiguous. 2. **Accept.** 3. **Reject.** This requirement has already been captured in clause 7.18 of the Access Arrangement. 4. **Reject.** We consider our approach is preferable as it provides guidance as to what happens should a tariff variation notice be not submitted or rejected. We note that the AER has not provided reasons for rejecting this clause.
	Figure 11.2 such that: 1. Changes to the notation of indices 2. Repeats the definition of parameters already defined. 3. Sets the side constraint to allow a 2 per cent side constraint;	 1. **Reject.** 2. **Reject** Repetition of definitions is unnecessary. 3. **Reject.** We maintain our position that a 10 per cent side constraint is appropriate. This is discussed in section 12.2.1.
	Figure 11.3 such that it: 1. Changes to the notation of indices 2. Repeats the definition of parameters already defined. 3. Removes the requirement for A'_t to be zero in 2017/18 4. Substitutes 'AER' for ‘Relevant Regulator. 5. Adds a requirement for a Carbon Scheme to be approved by the AER. 6. Changes the definition of Definition of real WACC; 7. Removes ‘Relevant’ from the name of the ‘Relevant Tax Factor’	 1. **Reject.** 2. **Reject.** 3. **Partially accept.** See section 12.2.2**.** 4. **Reject.** Unnecessary and inconsistent with the remainder of the Access Arrangement. 5. **Reject.** The Access Arrangement provides a clear definition for what constitutes a Carbon Scheme. 6. **Reject.** We maintain that our definition is clearer and more appropriate. 7. **Reject.** Using the term ‘Relevant tax’ is more accurate.
	Figure 11.4 such that 1. Changes to the notation of indices 2. Repeats the definition of parameters already defined. 3. Defines PT_t to be zero in 2016/17 rather than 2015/16. 4. Changes the definition of AP_t to only include any determined pass through amount that the AER approves in whole or in part.	 1. **Reject.** 2. **Reject.** 3. **Partially accept.** See section 12.2.2**.** 4. **Reject.** The Determined Pass Through Amount by definition (see clause 7.11) only includes amounts the AER has approved to be passed through.
Intra-year tariff variation (11-2)	Remove clause 7.5 of AA	**Reject.** We maintain our position that allowing intra-year tariff adjustments, in exceptional circumstances and with AER approval, is in consumers’ long term interests. This is discussed in section 12.3.3.
Cost pass through events (11-3)	Remove: 1. short term trading market event; 2. supply curtailment event; 3. general pass through event.	**Reject.** Our consideration of the pass through events is provided in section 12.3.

(11-4)	Amend definition: 4. regulatory change event; 5. service standard event; 6. insurance cap event; 7. insurer credit risk event; 8. terrorism event; 9. natural disaster event; 10. network user failure event	
Fixed principle (11-5)	Amend to provide that the principle is a fixed principle for 2016-2021 AA period only	**Reject.** See section 12.3.4.

12.2.1 Side constraint

While not required by the Rules, ActewAGL Distribution proposed to apply a side constraint at the tariff class level, recognising that:

- the AER has adopted side constraints in previous gas access arrangement determinations where a WAPC has applied;
- a side constraint reduces price volatility and provides additional certainty to customers on annual price movements; and
- the Energy Consumer Reference Council (ECRC) has told ActewAGL Distribution that price shocks should be avoided.

In the draft decision the AER accepts the proposal to apply a side constraint, but requires ActewAGL Distribution to replace the proposed 10 per cent constraint with a tighter constraint of 2 per cent.

The AER says that ActewAGL Distribution argued for a 10 per cent constraint on the basis that the AER had approved a 10 per cent constraint for Jemena Gas Networks (JGN). In rejecting our proposed 10 per cent constraint the AER said that it had accepted JGN's 10 per cent due to specific historical circumstances and that the same circumstances did not apply to ActewAGL. The AER went on to observe that those circumstances included that fact that the AER's approval of a 10 per cent constraint was "required to allow it [JGN] to set its reference tariffs on a cost reflective basis" and that the 10 per cent figure could be applied to JGN for the second consecutive regulatory period because JGN was "*still in the process of moving tariffs to cost reflective levels*".[128]

In addition, the AER also noted that a 2 per cent side constraint had "*precedence*" because it was the "*constraint adopted for electricity networks as set out in the NER*".[129]

ActewAGL Distribution disagrees with the AER's reasoning and conclusions for the following reasons.

[128] AER 2015, *Draft decision, Attachment 11, Reference tariff variation mechanism*, November, p. 11-15

[129] AER 2015, *Draft decision, Attachment 11, Reference tariff variation mechanism*, November, p. 11-15

ActewAGL Distribution also needs flexibility to move to new cost reflective tariffs

We disagree with the AER's conclusion that the need to transition to cost reflective tariffs was particular to JGN's circumstance. In our view, ActewAGL Distribution is in the same circumstance.

As the AER notes several times in *Attachment 10: Reference tariff setting* of the draft decision, ActewAGL Distribution has proposed a shift to a more cost reflective tariff structure. For example, the AER comments that:

> *the proposed tariff structure provides for more cost reflective tariffs which will send more appropriate price signals to end customers about their use of the network.*[130]

In the draft decision the AER has accepted the new reference tariff structure, and also the proposed shift from the fixed schedule of tariffs to a WAPC. To properly implement these significant changes, and ensure that the potential benefits can be delivered to consumers, we need greater flexibility than a 2 per cent side constraint would provide. In our Tariff Structure Statement (submitted to the AER as part of our June 2015 submission), we signaled that changes greater than, and less than, the average price path may be required in the shift to the new tariff structure. We have also discussed with the ECRC the potential changes in network charges for different types of customers, and how these will need to vary from the average.

The National Electricity Rules recognise the need for flexibility

In our June 2015 submission we noted that while a 2 per cent side constraint is specified in the National Electricity Rules (NER), the constraint does not apply to electricity network service providers in the first year of the regulatory period. The NER recognise that it is important for service providers to have flexibility to align, or re-align, costs and tariffs. However, in contrast to the side constraint in the NER, the 2 per cent side constraint required in the AER's draft decision would apply in each year, including the first year of the access arrangement period. This would unnecessarily constrain our ability to move to cost reflective tariffs.

Furthermore, flexibility is even more important in gas network pricing than in electricity network pricing, as volumes and consumer behavior in relation to gas are less stable than they are for electricity.

In consequence, we do not agree that a 2 per cent constraint is in the long term interests of consumers and we have therefore not adopted it in our revised proposal. Instead, we have retained the 10 per cent side constraint that we proposed in our June 2015 submission.

12.2.2 Annual tariff mechanism formulae

The AER's draft decision made two changes to formulae in the annual tariff variation mechanism relating to the cost pass through and automatic adjustment factors.

[130] AER 2015, *Draft decision, Attachment 10, Reference tariff setting*, November, p. 10-18

Pass through factor

For the pass through factor the AER defined PT_t to be zero in 2016/17 rather than 2015/16. We presume that the AER intended to set PT'_{t-1} (rather than PT_t) to zero in 2016/17 and if so agree with the AER and have made this change. The revised pass through factor is as follows (changes in green highlight):

Cost Pass Through factor

$$PT_t = \frac{(1 + PT'_t)}{(1 + PT'_{t-1})} - 1$$

where:

PT'_{t-1} is:

(a) zero when t-1 refers to Financial Year ~~2015/16~~ 2016/17; and

(b) the value of PT_t determined in the Financial Year t-1 for all other Financial Years in the ~~Applicable~~ 2016 Access Arrangement Period,

and

$$PT'_t = \frac{AP_t}{(1 + CPI_t)(1 - X_t)(1 + A_t)\sum_{x=1}^{n}\sum_{y=1}^{m} p_{t-1}^{xy} q_{t-2}^{xy}}$$

The first annual tariff variation mechanism formula will be applied to set prices for 2017/18. This means that t will be 2017/18 and t-1 will be 2016/17. As there has been no previous annual tariff variation we set $PT'_{2016/17}$ to be zero to ensure that the pass through factor only works to recover (or return) the determination pass through amount.

Automatic adjustment factor

In regards to the automatic adjustment factor the AER removed the requirement for A'_t to be zero in 2017/18. We accept this change which has the effect of applying the automatic adjustment factor to 2015/16. However, this needs to be coupled with also changing the requirement for A'_{t-1} to only be zero in 2016/17 (rather than 2016/17 and 2017/18). Otherwise the formula may generate an over or under recovery in 2018/19.

The revised automatic adjustment factor is as follows (changes in green highlight):

1. Automatic adjustment factor (A)

$$A_t = \frac{(1 + A'_t)}{(1 + A'_{t-1})} - 1$$

where:

A'_{t-1} is:

1.1. zero when t-1 refers to Financial Year~~s~~ 2016/17 ~~or 2017/18~~; and

1.2. the value of A'_t determined for the Financial Year t-1 for all other years;

and

A'_t is:

~~1.3. zero when t refers to Financial Year 2017/18; and~~

~~1.4. for all other years:~~

$$A'_t = \frac{(L_{t-2} + U_{t-2} + C_{t-2} + T_{t-2})\left[(1 + realWACC_t)^2 (1 + CPI_{t-1})\right]}{(1 - X_t)\sum_{x=1}^{n}\sum_{y=1}^{m} p_{t-1}^{xy} q_{t-2}^{xy}}$$

The automatic adjustment factor will first be applied as part of the annual tariff variation mechanism in setting prices for 2017/18. There is no $A'_{2016/17}$ from a prior year so we have set it to zero for completeness. This ensures that the automatic adjustment factor correctly adjusts for the license fee, UAG, Carbon Cost and Relevant Tax factor amounts.

12.3 Cost pass through mechanism

Cost pass through mechanisms provide network service providers an opportunity to recover (and return) unexpected and uncontrollable changes in cost in a manner akin to a workably competitive market. The purpose is to allow recovery of efficient costs, thereby promoting the efficient operation and use of, and efficient investment in, gas services and thus the NGO.[131]

12.3.1 Access arrangement proposal

In preparing the 2016-21 access arrangement proposal we reviewed the cost pass through events defined in the 2010-15 access arrangement having regard to the NGO, the revenue and pricing principles and, although they do not form part of the gas regulatory framework, the nominated pass through event considerations as defined in the NER.

[131] AEMC 2012, *National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012 Rule Determination,* November, p.18 Appendix 12.01. See where the AEMC recognized that cost pass throughs enable the service provider to recover the efficient unforeseen costs of events outside the provider's control and that the inability to recover these efficient costs would, over the long term, adversely affect the efficient investment in, and operation of, the provider's network.

Taking the nominated pass through event considerations into account, as well as the NGO and the revenue and pricing principles, we proposed, in our June 2015 submission, the following revisions to the cost pass through events in the 2010-15 access arrangement:

- Removing four cost pass through events. We considered that these events would no longer be needed as cost changes would be captured by the regulatory change and general pass through events (in the case of the National Energy Customer Framework/National Gas Connections Framework Event) or will be captured by the introduction of the automatic adjustment factor (in the case of the Carbon Pollution Reduction Scheme, and Specified Uncontrollable Cost Event).
- Retaining five cost pass through events. We proposed changes to the definition of some events to enhance consistency with other access arrangements and address the AER's previously stated concerns.
- Adding five cost pass through events, including the insurance cap event, insurer credit risk event, terrorism event, natural disaster event and network user failure event which have been largely accepted by the AER in other regulatory decisions.

We also proposed changes to the cost pass through notification and approval process specified in the 2010-15 access arrangement to provide for greater consistency with JGN's 2015-20 access arrangement to reduce the administrative burden for both the AER and ActewAGL Distribution.

Finally, we proposed to introduce a clause to allow cost pass through amounts incurred in one access arrangement period to be recovered in subsequent access arrangement periods, consistent with the cost pass through provisions in the NER. Without such provision, cost pass through amounts occurring late in a regulatory period would likely not recovered (or returned) unless an administratively costly mid-year tariff variation is implemented.

12.3.2 The AER's draft decision and our response

12.3.2.1 Overview

The AER did not approve the proposed cost pass through mechanism, instead requiring a series of revisions summarised in Table 12.2 below.

Table 12.2 Summary of the AER's proposed revisions to the cost pass through mechanism

Component	AER draft decision
Cost pass through events	Amendments to the definitions of the following events: • Regulatory Change Event • Service Standard Event • Insurance Cap Event • Insurer Credit Risk Event • Terrorism Event • Natural Disaster Event • Network User Failure Event Removal of the following events: • Short Term Trading Market Event • Supply Curtailment Event • General Pass Through Event
Intra-year tariff variation	Removal of this mechanism
Fixed principle	Amend the access arrangement to provide that the principle is a fixed principle for the 2016-21 access arrangement period only

The following sections discuss pertinent elements of the cost pass through mechanism such as the allocation of risk, the incentive properties and how the cost pass through mechanism is in the long term interests of consumers. We then summarise our proposal, the AER's draft decision, and explain the reasoning behind our revised proposal first by pass through event, then with regard to the intra-year tariff variation and finally the fixed principle.

12.3.2.2 Cost pass through mechanism

The allocation of risk

The AER indicated that its approach, although not required by the Rules or the NGL, would consider "…whether the risk transferred to consumers via the pass through mechanism is appropriate."[132] The AER explains that:

> *A factor for us to consider, which is reflected in our approach to assessing pass throughs, is who is best placed to manage risk. It is acknowledged practice that the party who is best placed to manage the risk should bear the risk. If the service provider, or customers, are fully exposed to a risk this may lead to adverse outcomes.*

Consideration of this factor, however, must complement the fundamental purpose of the cost pass through mechanism. The purpose of the cost pass through mechanism is not solely to allocate risk between service providers and consumers but to support the incentive regime that underpins the regulatory framework. As the AEMC notes the fundamental objective of regulation is:

[132] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, November, p.11-26 – 11-27

> *..to reproduce, to the extent possible, the production and pricing outcomes that would occur in a workably competitive market in circumstances where the development of a competitive market is not economically feasible.*[133]

Following from this objective (and in the same decision) the AEMC introduced the cost pass through mechanism into the NER explaining that:

> *The objective of the cost pass-through is to provide a degree of protection for the TNSP from the impact of unexpected changes in costs outside of its control. The Commission considers that such a mechanism provides a reasonable reflection of the operation of a competitive market where efficient costs are eventually passed through to customers, whether they are expected or not. Such a mechanism lowers the risks faced by the TNSP, which would otherwise have to be compensated for in the calculation of regulated revenues.*[134]

The cost pass through mechanism works to ensure that prices reflect unexpected efficient cost movements, as prices do in workably competitive markets.

The AEMC subsequently added the nominated pass through event considerations to the NER. These considerations guide what allocation of risk is appropriate:

> *…the intention of the nominated pass through considerations, is that a pass through event should only be accepted when it is the least inefficient option and event avoidance, mitigation, commercial insurance and self-insurance are found to be inappropriate. That is, it is included after ascertaining the most efficient allocation of the risks between NSPs and end consumers. However, these are considerations only, therefore the NSP and the AER can come to a mutual understanding that a cost pass through event is inconsistent with the factors for consideration, but may still be the more efficient mechanism.*[135]

Incentives inherent in the cost pass through mechanism

We also note that the cost pass through mechanism in the NER (and implemented in ActewAGL Distribution's proposed access arrangement) maintains incentives on NSPs to only incur efficient costs by creating a credible threat of a retrospective review.[136] Clause 7.12(c) of ActewAGL Distribution's access arrangement enacts this by requiring the AER in determining the Determined Pass Through to take into account:

> *the efficiency of the Service Provider's decisions and actions in relation to the risk of the Cost Pass Through Event, including whether the Service Provider:*

---

[133] AEMC 2006, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006) no.18,* p.93 Appendix 12.02

[134] AEMC 2006, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) rule 2006 No.18,* p.104 Appendix 12.02

[135] AEMC 2012, *Rule Determination: National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012,* p.20 Appendix 12.01

[136] AEMC 2006, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) rule 2006 No.18,* p.106 Appendix 12.02

(A) *has failed to take any action that could reasonably have been taken in respect of that event; or*

(B) *has taken or omitted to take any action in response to the event, where such action or omission has materially increased the magnitude of the change in costs in respect of the event*.

How the cost pass through mechanism is in the long term interests of consumers

The long term benefits to consumers from the cost pass through mechanism are apparent when the counter factual of a regulatory regime without cost pass throughs is considered. Without the cost pass through mechanism service providers cannot recover efficient costs from the occurrence of an unexpected uncontrollable event. This leaves service providers with two options.

First, a service provider could reduce expenditure below efficient levels. This could be achieved by either limiting measures to address the impact of the event or inefficiently reducing expenditure elsewhere. For instance, if an insurer became insolvent and premiums materially increased, a service provider could simply not obtain insurance in order to achieve expenditure below efficient levels. This option would not be in the long term interests of consumers as it could leave the service provider (and in turn consumers) exposed to risks it would be efficient to insure against. Alternatively, expenditure in another area (such as maintenance) could be inefficiently reduced or postponed to offset the increase in costs, which could ultimately result in higher long terms costs. Both of these outcomes would not be in the long term interests of consumers as they would result in the inefficient operation of network services and inefficient long-term outcomes with respect to the price, quality, safety, reliability and security of supply of gas.

The second option service providers have is to absorb the cost impact, thereby lowering the return on investment. As a result, service providers would no longer expect to recover the efficient costs of future investments in the network, such as the replacement of assets as they reach the end of their economic life. This creates the incentive to reduce or cease future efficient investment resulting in the delivery of services that are not in the long term interests of consumers with respect to price, quality, safety, reliability and security of supply.

Consequently, a regulatory regime that provides an opportunity for service providers to recover their efficient costs, and in doing so provides appropriate incentives to service providers, is in the long term interests of consumers.

12.3.2.3 Cost pass through events

Regulatory Change Event and Service Standard event

In our June 2015 submission, we proposed a Regulatory Change Event, based on the regulatory change event specified in the NER, to ensure that any cost changes (which exceed the Administrative Cost Threshold) due to changes in regulatory obligations can be recovered or returned.

The words 'fall within no other category of cost pass through events' were not included in our definition of Regulatory Change Event. These words appeared in the definition of General Pass Through Event and so were not needed in the definition of Regulatory Change Event. For efficacy, there can only be one pass through event which includes these words. We also noted that these words are superfluous as the opening words of clause 7.6 of our proposed 2016-21 access arrangement provide that an event that falls within more than one of the pass through events defined in the access arrangement constitutes a single 'Cost Pass Through Event' for the purposes of clause 7.6.

ActewAGL Distribution also proposed a Service Standard Event that is triggered when a legislative or administrative act or decision changes how Reference Services are to be provided. This enables the consequent cost changes (which exceed the Administrative Cost Threshold) to be recovered or returned.

For both the Regulatory Change Event and Service Standards Event we considered that the word ‘substantially’ included in the NER definition added uncertainty[137] and, in any event, is unnecessary given that an Administrative Cost Impact threshold applies. Accordingly, we removed ‘substantially’ from these definitions.

AER draft decision

The AER, while agreeing in principle to a Regulatory Change Event and Service Standard Event, did not accept the proposed definitions. The AER required amendments to the definition in the case of the regulatory change event to ensure that the event only occurs if it falls within no other category of pass through event.

In relation to both the service standard event and regulatory change event, the AER required revisions to the definitions of those events to ensure that:

1. the event only occurs during the course of an access arrangement period;
2. the word <u>substantially</u> is included consistent with the NER; and
3. the event must materially increase or materially decrease the costs to the service provider of providing the Reference Service.

The AER noted that its alternative definitions provide greater regulatory consistency across ActewAGL Distribution’s electricity and gas networks.[138] The AER noted that the cost pass through events in the NER were developed by the AEMC to achieve consistency with the NEO, that the NEO and NGO are sufficiently similar and therefore that the events should be defined consistently.[139]

[137] JGN 2015, *Response to the AER’s draft decision & revised proposal,* p.127 Appendix 12.03

[138] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21, Attachment 11 – Reference tariff variation mechanism*, p.11-25

[139] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21, Attachment 11 – Reference tariff variation mechanism*, p.11-25

The AER also reiterated its previous consideration, in the final decision for JGN's 2015-21 access arrangement, that the word 'substantially' in the definition for the regulatory change event in the NER created an additional requirement to the materiality threshold.

ActewAGL Distribution response

We have considered each of the four changes made by the AER. We have accepted the change to ensure that the event only occurs during the course of the 2016 Access Arrangement period. However, we do not agree with the AER's three other revisions and have not made the corresponding changes.

Our revised Regulatory Change event is as follows (change in green highlight):

> ***Regulatory Change Event*** *means a change in a regulatory obligation or requirement that occurs during the 2016 Access Arrangement Period and affects the manner in which ActewAGL provides the Reference Service.*

In the alternative, if the AER is not convinced by our reasoning, we consider the AER should apply the regulatory change event definition it approved for JGN's 2015-20 access arrangement:

> ***Regulatory Change Event*** *means a change in regulatory obligation or requirement that falls within no other category of Cost Pass Through Event and substantially affects the manner in which the Service Provider provides the Reference Service.*

Although we consider that this definition does not achieve the NGO to the greatest degree (as the events we propose do) the event is preferable to the event included in the draft decision. We consider the event to be simpler and will enhance consistency in access arrangements in NSW/ACT, a consideration the AER must have regard to as per Rule 97(3)(d).

Similarly we have revised the definition of the Service Standard Event (change in green highlight)

> ***Service Standard Event*** *means a legislative or administrative act or decision that occurs during the 2016 Access Arrangement Period and has the effect of:*
>
> *(a) varying the manner in which ActewAGL is required to provide the Reference Service; or*
>
> *(b) imposing, removing or varying the minimum service standards applicable to the Reference Service; or*
>
> *(c) altering the nature or scope of the Reference Service provided by ActewAGL*

We provide our response by proposed revision in turn below.

1. *the event can only occur if it falls within no other category of pass through event*

In principle we agree that any event can only fall into the definition of a single cost pass through event. For this reason our proposed access arrangement is written such that there cannot be more than one cost pass through event even if it fits the definition of more than one event (see the introductory sentence of clause 7.6).

We agree with the AER that these words can only appear in one definition. However, we have retained the general cost pass through event and therefore no change is needed for the regulatory change event.

2. *only occurs during the course of an access arrangement period*

We have accepted this revision. We discuss how our revised access arrangement addresses cost pass through events from the 2010-16 access arrangement period in section 12.3.4.

3. *The inclusions of the word 'substantially'*

We proposed removing the word 'substantially' as it adds unnecessary uncertainty. While we are sympathetic to the AER's desire for consistency we consider that this must be balanced against the need to ensure that the pass through mechanism is in the long term interests of consumers.

We note that AER considers an event to be substantial if the change was beyond the service provider's control, there were no other available means of mitigation, there was a financial impact on the service provider's business that well exceeded the financial threshold and there was a clear and demonstrable impact on the provision of the reference service.[140]

We are concerned by the AER's interpretation of the word 'substantially' in the NER, specifically the AER's apparent view that it creates a dual threshold for a cost pass through event to be both 'substantial' and 'material'. This interpretation is inconsistent with the policy intent expressed when the NER provision was introduced. Specifically, at no point in its determination does the AEMC indicate that a dual threshold is intended. Instead, the materiality threshold is referred to as a single threshold. The AEMC determination states:

> *…the threshold for a pass through is important to ensuring the stability and predictability of the revenue cap regime for both the regulator and regulated businesses. Removing the threshold would lead to greater uncertainty and increase the administrative costs for the AER to determine what constitutes a material event.*[141]

This policy intent is not reconcilable with the AER's interpretation of the meaning of the regulatory change event.

4. *must materially increase or materially decrease the costs to the service provider of providing the Reference Service.*

ActewAGL Distribution considers this clause unnecessary as ActewAGL Distribution can only seek a cost pass through if as a result of a cost pass through event there is a change in costs that satisfies the Administrative Cost Impact threshold - that is, a change in costs in any financial year as a result of the event equal to or greater than 1% of smoothed forecast revenue for that year in the AER's final decision (see clause 7.7). The materiality threshold established by the NER is therefore already reflected in the access arrangement. We also note that the AER's required addition adds uncertainty and adds administrative costs (which the AER must have regard to under Rule 97(3)(b)) as it uses the word "materially" rather than using the "Administrative Cost Impact" phrase which is already defined in the Access Arrangement.

---

[140] AER 2015, *JGN Access Arrangement 2015-20 Final Decision, Attachment 11 – Reference tariff variation mechanism*, p.11-13 – 11-14 Appendix 12.11

[141] AEMC 2006, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006) no.18* p. 106 Appendix 12.02

Insurance Cap Event

In our June 2015 submission, we proposed to include an Insurance Cap Event for the circumstances where an insurance claim is made but the actual costs exceed the policy limit.

As part of ActewAGL Distribution's electricity distribution determination process, the AER altered ActewAGL Distribution's proposed insurance cap event definition to define the relevant policy limit to be the greater of the actual policy limit and the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums in ActewAGL Distribution's forecast opex allowance. In its final decision on ActewAGL Distribution's 2015-19 electricity distribution determination, the AER describes the policy intent of its proposed definition as being to:

> *…counter purchasing insurance at a lower level than that which informed its approved opex forecast. It does this by adopting, as a threshold, the greater of the assumed insurance level and that which the distributor goes on to purchase. In this way, consumers will not bear the cost of an insurance cap event where the distributor has chosen to spend less on insurance than was prudent and efficient given its approved opex.*[142]

ActewAGL Distribution has concerns with the AER's alternative definition as it:

- lacks certainty of meaning in that the policy limit commensurate with the allowance for insurance premiums in ActewAGL Distribution's forecast opex allowance is incapable of being ascertained; and
- is, in any event, unnecessary to address the AER's policy concern.[143]

While the policy intent is unobjectionable, we outlined significant concerns with the AER's alternate definition as it is premised on a policy limit that is 'explicitly or implicitly commensurate' with the allowance being ascertainable.[144] The difficulty in determining this amount was highlighted by the AER itself in its Final Decision on ActewAGL Distribution's electricity distribution determination where it stated its '…task is to determine an efficient level of total opex for a prudent service provider to meet the opex objectives over a five year regulatory control period' and not to 'approve specific projects.'[145]

We addressed the AER's policy concern by the operation of the pass through event definition together with the pass through framework in the access arrangement, specifically clause 7.12 which requires the AER, in making a pass through decision, to take matters into account which include the efficiency of ActewAGL Distribution's decision and actions (see section 12.3.2.2). This consideration could include the policy limit of the relevant insurance policy.

---

[142] AER 2015, *Final Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination:* Attachment 15, April, p. 15-12 - 15-13 Appendix 12.12

[143] ActewAGL Distribution 2015, *Revised Regulatory Proposal 2015-19,* January, pp. 541-542 Appendix 12.04

[144] ActewAGL Distribution 2015, *Revised Regulatory Proposal 2015-19,* January, p.542 Appendix 12.04

[145] AER 2015, *Final Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination: Attachment 7*, April, pp.7-37 – 7-38 Appendix 12.12

We considered that the proposed definition for this event achieves the NGO to a greater degree as, combined with the operation of the pass through framework in the access arrangement, it addressed the AER's policy concern and avoids creating unnecessary uncertainty.

AER draft decision

The AER accepted that an insurance cap event would protect ActewAGL from high cost impact events that would be uneconomical to insure against considering that consumers benefit because they are not required to fund excessive premiums where insurance, if available, would be uneconomic.[146]

The AER proposed revisions to the definition for consistency with its recent decision for JGN for the period 2015-20. Specifically this required:

1. Defining the relevant policy limit to be the greater of the level of insurance ActewAGL has purchased and that assumed or provided for in determining its approved opex.
2. Clarifying that both ActewAGL Distribution's actual insurance policy and the level of insurance that an efficient prudent service provider would obtain are relevant.
3. Although not explained, adding a requirement for a benefit of a payment to be received under a relevant insurance policy.
4. Including in the definition a requirement that actual costs increase.

ActewAGL Distribution response

We have considered the AER's draft decision and accepted the revisions to clarify what the AER will consider and to require that there is an actual cost increase. However, we have not accepted the two other changes as we consider that they do not implement the policy intent of the cost pass through event. The revised Insurance Cap Event is now defined in the access arrangement as follows (changes shaded in green):

> ***Insurance Cap Event*** *means the occurrence of an event whereby:*
>
> *(a) ActewAGL makes a claim or claims under a relevant insurance policy that satisfies the conditions of insurance under that policy;* ~~*and*~~
>
> *(b) ActewAGL incurs costs beyond the actual policy limit of the relevant insurance policy as a result of the event that gives rise to the relevant claim; and*
>
> *(c) The costs beyond the actual policy limit of the relevant insurance policy increase the costs to ActewAGL of providing the Reference Service.*
>
> *For the purposes of this definition:*
>
> *(d) A relevant insurance policy is an insurance policy held during the* ~~*Applicable*~~ *2016 Access Arrangement Period or a previous period in which access to the* ~~*Network*~~ *pipeline services was regulated; and*

[146] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, p.11-26 – 11-27

(e) *ActewAGL will be deemed to have made a claim on a relevant insurance policy if a claim is made by a related party of ActewAGL in relation to any aspect of the Network or ActewAGL's business.*

Note for the avoidance of doubt, in making a determination on an Insurance Cap Event, the Relevant Regulator will have regard to, amongst other things:

(f) *the insurance policy for the event; and*

(g) *the level of insurance that an efficient and prudent service provider would obtain in respect of the event.*

Our consideration of the AER's proposed revisions to the relevant policy limit, clarifications to what the AER will have regard to and the requirement for a benefit of a payment or payments to be received are addressed in turn.

1. *The relevant policy limit*

We agree with the AER's reasoning, in that care must be taken to ensure the service provider does not have a perverse incentive to reduce its expenditure on insurance. As we noted in our June 2015 submission we consider this policy concern unobjectionable. However, we are concerned that the AER's proposed revision does not implement the AER's intent. The AER draft decision states:

> *…Our preferred definition makes these considerations explicit in the context of this event, and provides transparency and increased regulatory certainty around how we will assess an application.*
>
> *Applied to the supporting definition of the relevant policy limit for this event, it allows us to measure the level of insurance actually purchased with that assumed by the service provider and/or approved by us in the total forecast opex for the period. For example, to the extent that a change in approved opex was informed by an assessment that an increase in the level of insurance was prudent and efficient, we would take into account the service provider's reasons for not proceeding with that increased amount. This does not preclude a finding that a decision not to proceed was appropriate, and that the actual policy limit should prevail. It simply balances the incentive to reduce opex through underspending rather than through genuine efficiencies.* (underlined emphasis added)[147]

This text highlights a scenario where a network service provider may make a decision, acting efficiently in accordance with accepted good industry practice, to reduce opex by lowering the insurance cap. Here the AER presumes it has the power to make a finding that this decision is appropriate and the actual policy limit should prevail.

[147] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, p.11-28

Although we agree that the AER should have the discretion to determine what the appropriate policy limit and consequent pass through amount is, the definition proposed by the AER needlessly limits this discretion as it defines the relevant policy limit as the greater of:

- the Service Provider's actual policy limit at the time of the event that gives, or would have given rise to the claim; and
- the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the Access Arrangement Period.

Under such a definition, the AER's discretion would be limited as the definition may prevent the event from occurring. Specifically, the policy limit assumed or provided for in forecasting opex at the time of the access arrangement is approved (putting aside the ambiguity in determining what is implicitly commensurate with the allowance) may be substantially different from a new actual policy limit. If the new limit is lower and ActewAGL Distribution incurs costs beyond that new limit, even if the decision to change the policy limit was made acting efficiently in accordance with good industry practice, no insurance cap event would occur and the AER would not be able to exercise its discretion in the manner foreshadowed in its draft determination.

Our proposed definition solves this issue by not defining the relevant policy limit. As the pass through event is coupled with clause 7.12 of our proposed access arrangement the AER is required to take into account ActewAGL Distribution's decisions and actions and in turn whether any change to the policy limit was efficient. With this definition the AER has the discretion to determine what the appropriate policy limit should be and the consequent pass through amount. This definition thereby implements the AER's policy intent.

2. *Clarifications regarding what the AER will have regard to*

We have no objection to the AER's clarifications that both ActewAGL Distribution's actual insurance policy and the level of insurance that an efficient and prudent service provider would obtain are relevant to the assessment of an application under this event. These changes have been accepted and implemented.

3. *Requirement for a benefit of a payment or payments to be received*

ActewAGL Distribution has also not accepted the proposed revision to require a benefit of a payment or payments under a relevant insurance policy to be made for the Insurance Cap event to occur.

In contrast to ActewAGL Distribution's proposed definition, the AER's alternate definition conditions the occurrence of an insurance cap event on ActewAGL Distribution 'receiv[ing] the benefit of a payment or payments under a relevant insurance policy'.

We object to the conditioning of the occurrence of an insurance cap event on the receipt of a benefit under the relevant policy because this will prevent ActewAGL Distribution from recovering costs beyond the policy limit where a benefit is not received regardless of the circumstances in which this occurs. ActewAGL Distribution may not receive a benefit notwithstanding that a claim is made in accordance with the insurance policy for various reasons, including for example the insolvency of an insurer.

While the AER has accepted an insurer credit risk event this will only enable recovery of costs that would have been covered by the insolvent insurer. It would not enable us to recover costs above the insurance cap, the purpose of this pass through event.

It follows that the conditioning of the occurrence of an insurance cap event in the manner proposed by the AER would operate to deny ActewAGL Distribution the very protection from high cost impact events it would be uneconomical to insure against that the AER recognises is necessary. For example, the AER's alternative definition would not benefit consumers because it would not cover circumstances where ActewAGL Distribution does not receive any benefit under the policy for reasons wholly unrelated to the merits of its claim and notwithstanding that ActewAGL Distribution could not have acted to prevent this. Such an outcome would likely operate to deny ActewAGL Distribution the opportunity to recover its efficient costs and is not consistent with the nominated pass through event considerations, the NGO or the RPPs.

Insurer Credit Risk Event

In our June 2015 submission, we proposed a cost pass through event for circumstances whereby an insurer becomes insolvent and, as a result, ActewAGL Distribution:

- incurs higher or lower costs for insurance premiums than would have otherwise applied;
- is subject to a materially higher or lower claim limit or a materially higher or lower deductible than would have otherwise applied under the relevant policy; or
- incurs additional costs associated with self-funding an insurance claim, which would otherwise have been covered by the insolvent insurer.

While we take precautions to mitigate exposure to an insurer credit risk event, there remains an ongoing risk that an insurer may fail. Accordingly, ActewAGL Distribution undertakes a series of precautions including, where possible, scrutinising market developments, insurer reputation, credit rating and financial stabilities of potential insuring entities. If an insurer does fail, ActewAGL Distribution could face considerable exposure, in circumstances that would be beyond its ability to control. To ensure that ActewAGL Distribution has the opportunity to recover at least its efficient costs, we proposed an Insurer Credit Risk event.

AER draft decision

The AER accepted that the options available to service providers to manage the risk of an insurer failure are limited and, given the rarity of such events, may in fact result in greater expenditure on insurance than is prudent or efficient.

The AER proposed three revisions to the cost pass through event. First to remove the provision to pass through costs associated with changes to insurance premiums as a result of an insurer becoming insolvent. The AER reasoned that insurance premiums are a typical business expense subject to ordinary market factors in the economy. The AER considered that this is a risk businesses are best placed to manage rather than customers. [148]

Second the AER defined the event to only occur when a nominated insurer becomes insolvent.

Third the AER limited the costs to specific existing or potential claims to the failed insurer. The AER considered this limitation important so that service providers do not have an incentive to delay purchase of alternative insurance.[149]

ActewAGL Distribution response

We have considered the AER's draft decision and do not accept the proposed revisions.

We have made this decision primarily because if an insurer fails it may be very costly for an insurer to issue new equity due to agency costs that arise from asymmetrical information in capital markets.[150] This could result in an increase to insurance premiums and/or deductibles regardless of whether ActewAGL Distribution insured with the failed insurer.

This occurred following the HIH collapse which led to large and sustained insurance premium increases – reported to be as much as 1,000 per cent for professional indemnity insurance and by 900% for public liability insurance.[151] HIH's competitors did not have capacity to absorb the market share left by HIH leading to a crisis in the availability and affordability of insurance.[152]

ActewAGL Distribution therefore maintains the pass through event as proposed as it allows for higher or lower costs arising from changes to either the insurance premiums or deductibles regardless of whether ActewAGL Distribution insured with the failed insurer, thereby ensuring this definition does not create an incentive to inefficiently delay obtaining insurance.

We agree with the AER that insurance costs are typical business expenses subject to ordinary market factors in the economy. However, there is a very low probability of costs rising so much as to exceed the materiality threshold. Further, as noted earlier in section 12.3.2.2, the purpose of the cost pass through mechanism is to allow material unexpected cost increases to flow through to prices as they would in a workably competitive market.

Terrorism Event

In our June 2015 submission, we included a terrorism cost pass through event based on the AER's definition in ActewAGL Distribution's 2014-19 electricity distribution determination and

---

[148] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, November, p.11-28

[149] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, November, p.11-28 – 11-29

[150] Cagle J. and Harrington, S 1995, *Insurance supply with capacity constraints and endogenous insolvency risk*, Journal of Risk and Uncertainty, Vol. 11 Issue 3, December, pp. 219-220

[151] The Treasury 2015, *Economic round up,* Issue 1, p.44 Appendix 12.05

[152] Attorney-General's Department 2006, *Available and affordable – Improvements in liability insurance following tort law reform in Australia*, .p.5 Appendix 12.06

JGN's 2015-20 access arrangement. We made amendments to clarify that cyber terrorism is included.

AER draft decision

The AER accepted the Terrorism event but proposed two revisions.

First, the AER did not accept the clarification that cyber terrorism is included. The AER considered that the risk of cyber-related attacks should be managed primarily through prudent and efficient steps to protect IT systems. The AER expressed concern that if there is too much reliance on ex-post measures ActewAGL Distribution will have disincentives to take prudent actions to manage risk.[153]

Second, the AER considered that it is preferable if the event definition explicitly requires the event to increase costs to the service provider.

ActewAGL Distribution response

We have considered the AER's draft decision. We maintain that the clarifications regarding cyber terrorism should be included for the reasons set out in our June 2015 submission but accept the AER's preference regarding the explicit requirement for a terrorism event to increase costs. Our revised definition (revisions shaded green):

> ***Terrorism Event*** *means an act (including, but not limited to, the use of force or violence, the threat of force or violence, attacks or other disruptive activities against, or the deliberate introduction of harmful code or viruses to, computer systems, computer networks, data and/or communication systems, or the threat of such attacks or disruptive activities, or of the deliberate introduction of such harmful code or viruses) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which increases the cost to ActewAGL in providing the Reference Service.*
>
> *Note for the avoidance of doubt, in making a determination on a Terrorism Event pursuant to clause 7.11 of this Access Arrangement, the AER will have regard to, amongst other things:*
>
> *(a) whether ActewAGL ~~the Service Provider~~ has insurance against the event;*
>
> *(b) the level of insurance that an efficient and prudent service provider would obtain in respect of the event; and*
>
> *(c) whether a declaration has been made by a relevant government authority that a terrorism event has occurred.*

Our reasoning in regards to the clarification of cyber terrorism and requirement for an increase in cost is provided below.

[153] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, pp.11-30 – 11-31

1. *Cyber terrorism*

We agree with the AER that the risk of cyber related attacks can and should be managed primarily through prudent and efficient steps to protect IT systems. As we outlined in our 2014-15 electricity networks revised proposal dated 20 January 2015 we have a range of measures in place to prevent acts of terrorism affecting our operations or to mitigate the impact of an event if one should occur. These include review and creation of security management plans based on ISO 31000 and HB 167 Security Risk management, detailed security standards, comprehensive security frameworks policies and procedures and participation in joint security exercises at both the federal and local government level.[154]

However, despite these prudent and efficient actions which are in accordance with good industry practice, a cyber terrorism event may still occur which cannot be avoided. This has been recognised by the Australian Government's Cyber Security Strategy, which notes:

> *The inherent characteristics of a borderless, lightly regulated and largely anonymous online environment make it impossible to prevent all security incidents from occurring.*[155]

The recent ACSC Threat Report describes the threats networks of Australian organisations face from cyber espionage, cyber-attacks and cybercrime.[156] It notes that Australia's systems of national interest and critical infrastructure are vulnerable to malicious cyber activity. Significantly, in 2014 the top five non-government sectors assisted by the Computer Emergency Response Team Australia (CERT Australia) in relation to cyber security incidents were energy, banking and financial services, communications, defence, industry and transport.[157]

The following figures from the ACSC Threat Report set out:

- the number of incidents responded to by the Australian Signals Directorate (ASD) from 2011 to 2014. The figure on the left demonstrates that the number of incidents increased by approximately 72 per cent from 2011 to 2014;[158] and
- the number of incidents responded to by CERT Australia in 2014 which affected systems of national interest and critical infrastructure. The figure on the right demonstrates that the energy sector is the most likely target for cyber security threats.

[154] ActewAGL Distribution 2015, *Revised Regulatory Proposal 2015-19*, pp.550-551 Appendix 12.04

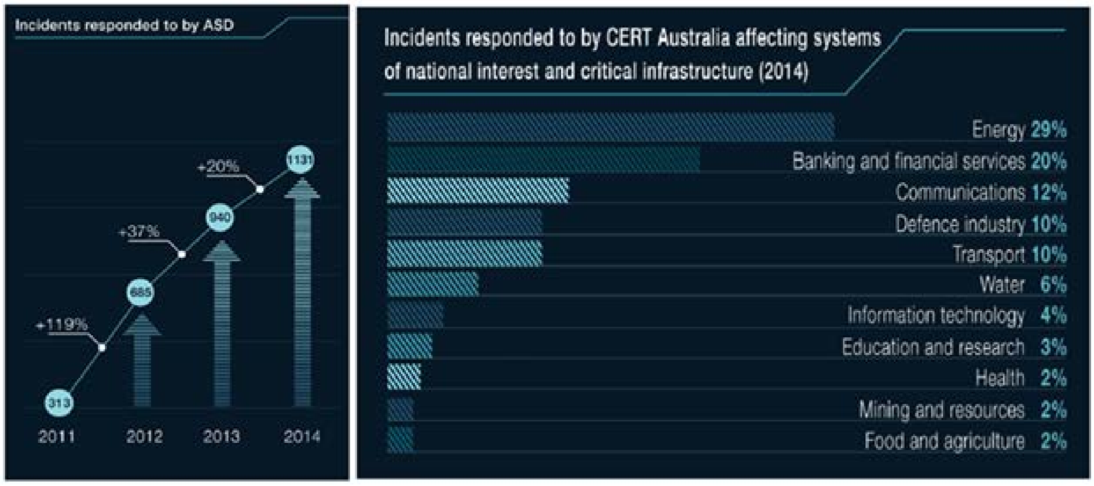
[155] Commonwealth of Australia 2009, *Cyber Security Strategy,* p.10 Appendix 12.07

[156] Australian Cyber Security Centre 2015, *2015 Threat Report*, July Appendix 12.08

[157] Australian Cyber Security Centre 2015, *2015 Threat Report*, July, p. 7 Appendix 12.08

[158] Australian Cyber Security Centre 2015, *2015 Threat Report*, July, p. 7 Appendix 12.08

Table 12.3 Cyber security incidents responded to by ASD 2011–2014 and incidents responded to by CERT Australia in 2014 affecting systems of national interest and critical infrastructure



Source: Australian Cyber Security Centre, *2015 Threat Report*, July 2015, figure 1, pp. 10 and 11.

A report by Gartner notes the cyber security incident concerning Sony Pictures as an example of potential impacts.[159] A recent breach of Target's IT systems resulted in approximately 40 million US citizens having their financial information stolen and a further 70 million having their personal data stolen. In addition, according to news reports there was a recent cyber attack on the Bureau of Meteorology's IT systems in response to which a classified report recommended the complete replacement of the Bureau's computer systems.[160]]

We note that the retrospective review enabled by clause 7.12 (see section 12.3.2.2) requires the AER to take into account the efficiency of the service provider's decisions and actions in relation to the risk of the event. This could include an analysis of the adequacy of the measures ActewAGL Distribution had in place at the time of a cyber terrorism event.

Accordingly, the cost of a cyber terrorism event is appropriately recovered through the cost pass through mechanism as it reflects an efficient allocation of risks and is in the long term interests of consumers.

2. *Requirement for an increase in cost*

No requirement for a change in cost was included in the terrorism cost pass through event as we considered it unnecessary. If there is no change in cost then the pass through mechanism will have no effect. However, we acknowledge the AER's preference for an explicit requirement to be included in the definition and have incorporated the proposed revision.

[159] Gartner, *Attack on Sony Pictures is a digital business game changer*, 9 February 2015.

[160] ABC News report (online), C*hina blamed for massive cyber attack on Bureau of Meteorology computer*, 2 December 2015 Appendix 12.09; ABC News report (online), *Classified report on Bureau of Meteorology cyber attack recommends computer system overhaul*, 3 December 2015 Appendix 12.10.

Natural Disaster Event

Our June 2015 submission included a cost pass through event for natural disasters. ActewAGL Distribution made two changes to the AER's definition included as part of the 2015-19 ActewAGL distribution determination and JGN's 2015-20 access arrangement:

- to clarify that natural disasters negligently caused by ActewAGL Distribution are excluded rather than all natural disasters which were a consequence of the acts or omissions of ActewAGL Distribution; and
- to ensure the cost pass through event is not restricted to natural disasters occurring during the 2016-21 access arrangement period.

AER draft decision

The AER considered that inclusion of a natural disaster event is consistent with the NGO and revenue and pricing principles. However, the AER did not accept the two changes made by ActewAGL Distribution and proposed revisions to remove these changes.

The AER did not accept the clarification to only exclude events negligently caused by ActewAGL Distribution rather than all events that were a consequence of acts or omissions made by ActewAGL Distribution. The AER considered that clause 7.12 of the proposed access arrangement (which requires the AER to take into account factors such as the efficiency of ActewAGL Distribution's decisions and actions in relation to the risk of the event) already provides an appropriate level of accountability in this respect and reinforces the importance of ActewAGL taking appropriate steps to prevent and mitigate the loss resulting from natural disasters.[161]

The AER also did not agree to remove the restriction of the event only applying to natural disasters occurring during the 2016-21 access arrangement period. The AER considered this restriction consistent with the prescribed pass through event in the ActewAGL Distribution 2014-19 electricity network distribution determination and in JGN's access arrangement.

ActewAGL Distribution response

We have considered the AER's draft decision and have accepted one of the revisions (being the second revision discussed above). We considered that the natural disaster event proposed achieves the NGO to a greater degree than the definition proposed by the AER. The revised natural disaster event is as follows (changes marked up in green):

> ***Natural Disaster Event*** *means any major fire, flood, earthquake or other natural disaster that occurs during the 2016 Access Arrangement Period and increases the costs to ~~the Service Provider~~ ActewAGL in providing the Reference Service, provided the fire, flood or other event was not a consequence of the negligent acts or omissions of ~~the Service Provider~~ ActewAGL.*
>
> *For the purposes of this definition, the term 'major' means an event that is serious and significant.*

[161] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, November, p.11-32

Note for the avoidance of doubt, in making a determination on a Natural Disaster Event pursuant to clause 7.11 of this Access Arrangement, the AER will have regard to, amongst other things:

a) *whether ~~the Service Provider~~ ActewAGL has insurance against the event;*

b) *the level of insurance that an efficient and prudent service provider would obtain in respect of the event; and*

c) *whether a relevant government authority has made a declaration that a natural disaster has occurred.*

Below we provide our detailed consideration of the AER's draft decision.

1. *Exclusion of non-negligent acts*

As noted in our revised regulatory proposal for our electricity network dated 20 January 2015, we have a series of measures in place to mitigate the impact of a natural disaster event should one occur. These include a suite of plans for any type of business interruption, a risk management methodology based on ISO 31000, and an appropriate level of commercial insurance.[162]

However, we note that an act or omission of a service provider acting efficiently, in accordance with accepted good industry practice, could be considered to result in a natural disaster. For instance, the premature equipment failure in a well-maintained facility could result in a bushfire. ActewAGL Distribution stresses that due to the series of controls in place this is a very low probability. We also note that it is unclear whether such an event could be considered to be a consequence of an act or omission of ActewAGL Distribution, as it would likely depend on the circumstances of the event.

Crucially the purpose of the cost pass through event is to ensure that network service providers have the confidence to respond efficiently if the low probability event occurs. If there is uncertainty as to whether a cost pass through event is triggered, this could create the incentive for a network service provider to not respond in the long term interests of consumers or avoid investment as outlined in section 12.3.2.2.

Clarifying that the pass through event only excludes natural disasters caused by negligent acts (rather than acts where ActewAGL Distribution was acting efficiently in accordance with accepted good industry practice) provides certainty and removes the potential disincentive to respond appropriately.

This change is complemented by clause 7.12 of our proposed access arrangement. We agree with the AER that this clause provides accountability and reinforces the importance of ActewAGL Distribution taking appropriate steps to prevent and mitigate loss resulting from natural disasters. These provisions ensure that the AER can take into account the efficiency of ActewAGL Distribution's decisions and actions in relation to the risk of the cost pass through event. In

[162] ActewAGL Distribution 2015, *Revised Regulatory Proposal 2015-19*, January, p.551-553 Appendix 12.04

determining a pass through amount the AER can assess whether ActewAGL Distribution failed to take action which would have either prevented or substantially mitigated the event.

Accordingly, the proposed natural disaster event definition coupled with the proposed cost pass through provision ensures that ActewAGL Distribution has the regulatory certainty and confidence to efficiently and prudently respond to a low probability high consequence event while also allowing for regulatory scrutiny to ensure only prudent and efficient costs can be recovered. This change is therefore in the long term interests of consumers and achieves the NGO to a greater degree.

2. *Restriction to the 2016-21 access arrangement period*

We removed the restriction of the event to one occurring in the 2016/17 - 2020/21 access arrangement period only with the intention of simplifying the event. We discuss how our revised access arrangement addresses cost pass through events from the 2010-16 access arrangement period in section 12.3.4.

Network User Failure Event

In our June 2015 submission, we proposed a Network User Failure Event. The Network User Failure Event is intended to cover the cost impacts that arise as a result of the significant administrative and logistical tasks that are required under NSW/ACT Retail Market Procedures to support the transfer of customers in retail market systems from one retailer to another – in a sudden and non-standard manner.

AER draft decision

The AER considered that a network user failure event, if appropriately defined, would support the NGO and revenue and pricing principles as a Network User Failure Event could provide an efficient alternative to ActewAGL Distribution investing in automated systems solely for transferring customers in a retailer of last resort event.[163]

However, the AER made several changes to the event to ensure consistency of the pass through event with that included in JGN's 2015-20 access arrangement. These changes include:

- specifying that the AER will have regard to the steps ActewAGL Distribution has taken to minimise costs;
- not including foregone revenue; and
- limiting the occurrence of the event to a RoLR event as defined in section 122 of the National Energy Retail Law.

ActewAGL Distribution response

ActewAGL Distribution has considered the AER's draft decision and has made the first of the changes set out above (that the AER will have regard to the steps ActewAGL Distribution has

[163] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, p.11-33

taken to minimise costs) but otherwise, ActewAGL Distribution considers that its proposed event achieves the NGO to a greater degree as it applies in a large number of circumstances. In these additional circumstances ActewAGL Distribution considers the most efficient risk mitigation mechanism is a cost pass through as it is not efficient for these circumstances to be prevented, be substantially mitigated or insured against.

The revised definition which ActewAGL now proposes in light of the Draft Decision is set out below, with the changes from the version proposed in our June 2015 Submission highlighted in green.

> ***Network User Failure Event*** *means the occurrence of an event whereby a User becomes insolvent or is unable to continue to supply gas to its customers, and those customers are transferred to another User. Notwithstanding the definition of Change in Cost, the Change in Cost associated with a Network User Failure Event is deemed to:*
>
> *(a) include amounts that ActewAGL is entitled to be paid (but which are or will be unpaid as a result of a Network User Failure Event) for the provision of the Reference Service, including the revenue impact ActewAGL sustains or will sustain as a result of those unpaid amounts; and*
>
> *(b) exclude costs that could be the subject of a pass through amount pursuant to rule 531 of the National Gas Rules or section 167 of the National Energy Retail Law.*
>
> *Note for the avoidance of doubt, in making a determination on a Network User Failure Event, the Relevant Regulator will have regard to, amongst other things, the extent to which ActewAGL has taken steps to minimise the costs associated with the event, both prior to, and after, the event occurs.*

Short Term Trading Market Event

In our June 2015 submission, we proposed to retain the Short Term Trading Market event that had been included in the ActewAGL Access Arrangement approved in 2010 to ensure that costs from the establishment of a trading hub could be recovered.

AER draft decision

The AER did not accept the retention of the Short Term Trading Market Event for two reasons. First, the AER noted that ActewAGL Distribution did not provide any evidence that a trading hub is likely to be developed in Canberra in the foreseeable future which “casts doubt about the relevance” of the proposed event. Second the AER agreed with Origin Energy that the event would be covered by the regulatory change event.[164]

ActewAGL Distribution response

ActewAGL Distribution has accepted the AER’s proposed revision to remove the Short Term Trading Market Event, on the basis that if an event occurs it would be covered by the regulatory change event.

[164] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, p.11-36

Supply Curtailment Event

In our June 2015 submission, we retained the supply curtailment event that had been included in the ActewAGL Access Arrangement approved in 2010 to ensure the recovery of material efficient costs incurred as a result of a gas shortfall, an event outside ActewAGL Distribution's control.

AER draft decision

The AER proposed revisions to remove the supply curtailment event as it considered that including this event weakens ActewAGL Distribution's incentives to properly mitigate the risk, and minimise the costs, of a gas shortfall.[165] The AER also considered that managing the risk of inadequate gas supply is a 'typical business expense' for ActewAGL Distribution and should not be passed through to consumers.[166]

ActewAGL Distribution response

We have considered the AER's draft decision and do not agree that removing a mechanism for ActewAGL Distribution to recover efficient costs incurred in responding to an uncontrollable event is in the long term interests of consumers.

We have, however, revised our proposal by deleting the supply curtailment event on the basis that this risk is addressed by the general cost pass through event. In the event that the general pass through event proposed by ActewAGL Distribution is not included in the Access Arrangement, ActewAGL Distribution would maintain that a supply curtailment event is required.

The AER states in its draft decision that:

> *Accepting a pass through event for gas shortfalls would weaken ActewAGL's incentives to properly mitigate the risk, and minimise the costs, of a gas shortfall. There are several potential risk mitigation strategies ActewAGL can undertake to help prevent a gas supply shortfall and minimise its costs in the event of one.*[167]

To be clear while there are options to mitigate the risk ActewAGL Distribution cannot control the occurrence of a supply curtailment event. As JGN has noted while there are several potential risk mitigation options available (maintaining an ongoing dialogue with market actors, provisions in reference service agreements and potentially insurance), these options cannot manage the risk exposure for all shortfall scenarios.[168]

JGN also drew the AER's attention to recent commentary and analysis, including from AEMO and the Department of Industry, of potential shortfalls of supply before concluding that:

---

[165] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, p.11-36

[166] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, p.11-36

[167] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, p.11-37

[168] JGN 2015, *Response to the AER's draft decision & revised proposal,* p.138 Appendix 12.03

> *JGN has virtually no ability to prevent or mitigate the impacts of such an event on its network, given that it would originate well upstream*[169]

Similarly, ActewAGL Distribution has virtually no ability to prevent the occurrence or mitigate the impacts of such an event on the ActewAGL Distribution gas network. Consequently, despite ActewAGL Distribution acting efficiently and in accordance with good industry practice, a gas supply shortfall might still arise.

If a gas supply shortfall occurs the costs in addressing the consequences of the event are not typical. As JGN explained there are significant safety issues that flow from a loss of gas pressure. If pressure is lost in any section of the network a critical high risk safety issue arises as it becomes possible for air to enter gas mains and form a combustible air-gas mixture within the pipes. An extensive emergency operational response is then required to safely shut down and re-commission gas mains before reconnecting and reinstating supply to each individual customer.

If the network is shut down due to a lack of supply there will be significant disruption for those impacted as supply within the network could be impacted for days and possibly weeks in order for the network sections to be purged of the remaining gas/air mixture before gas can be reintroduced and appliances re-lit at each site. For example, following the bushfires in Canberra it took about 5 days to restore supply to 5,600 customers.

As an event of this nature is not within ActewAGL Distribution's control and cannot be prevented, mitigated or insured against, a pass through event represents the most efficient allocation of risks.

Further we note that under clause 7.12 the AER is required to take into account whether ActewAGL Distribution could have taken any action to prevent or mitigate the event as part of a retrospective review of the event.

General Pass Through Event

In our June 2015sSubmission, we proposed to retain the General Pass Through Event from our 2010-15 access arrangement. The purpose of the General Pass Through Event is to ensure that costs from unforeseeable events are recovered.

The General Pass Through Event provides ActewAGL Distribution with certainty that if action is taken to address the impact of an unforeseeable event in the long term interests of consumers it will have the opportunity to recover efficient costs. Without the pass through event ActewAGL Distribution is not provided with the opportunity to recover the costs of unforeseeable events creating incentives which are not in the long term interests of consumers and outcomes which are not consistent with the revenue and pricing principles.

The AEMC has recognised that not allowing service providers to recover costs is not in the long term interests of consumers reasoning that:[170]

[169] JGN 2015, *Response to the AER's draft decision & revised proposal,* p.135 Appendix 12.03

[170] AEMC 2012, Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, 2 August 2012, p. 18 Appendix 12.01

…NSPs [Network Service Providers] should be provided the opportunity to recover their efficient costs in those limited circumstances where insurance is limited or not available on commercial terms and self-insurance is not appropriate. Not to do so would, over the long term, be likely to affect the efficient investment in, and efficient operation of, those networks. This is because, NSPs that cannot recover their efficient costs are reluctant to invest in their networks.

… This should; [sic] however, be limited to instances where efficient costs are incurred because unforeseen costs arise as a result of events outside an NSP's control.

The AEMC introduced into the NER (but not the Rules) a series of nominated pass through event considerations which are mandatory considerations and not preconditions to the acceptance by the AER of a nominated pass through event as part of a distribution determination.[171] The AEMC explains that:[172]

…the intention of the nominated pass through event considerations was to incorporate and reflect the essential components of a cost pass through regime in the NER. It was intended that in order for appropriate incentives to be maintained, any nominated pass through event should only be accepted when event avoidance, mitigation, commercial insurance and self-insurance are unavailable. That is, a cost pass through is the least efficient option for managing the risk of unforeseen events.

The intention is not to negate the need for cost pass throughs, or limit the AER's ability to respond to changes in the regulatory environment in a flexible and adaptive way. The nominated pass through event considerations are of a high level and do not stipulate any specific action.[173]

and

…the intention of the nominated pass through event considerations, is that a pass through event should only be accepted when it is the least inefficient option and event avoidance, mitigation, commercial insurance and self-insurance are found to be inappropriate. That is, it is included after ascertaining the most efficient allocation of the risks between NSPs and end consumers. However, these are considerations only, therefore the NSP and the AER can come to a mutual understanding that a cost pass through event is inconsistent with the factors for consideration, but may still be the more efficient mechanism.

These passages disclose that the intent of the nominated pass through event considerations is to ensure that appropriate incentives are maintained. However, the AEMC highlights in both passages the AER’s discretion, noting the AER’s ability to ‘respond to changes in the regulatory environment in a flexible and adaptive way’, that the relevant considerations ‘do not stipulate

[171] The legal character of the nominated event pass through considerations is evident from clause 6.5.10(b) of the NER and is affirmed by the relevant Rules extrinsic material: see AEMC 2012, Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, 2 August 2012, p. 20 Appendix 12.01

[172] AEMC 2012, Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, 2 August 2012, p. 20 Appendix 12.01

[173] AEMC 2012, Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, 2 August 2012, p. 19 Appendix 12.01

any specific action' and that the AER together with an NSP can 'come to a mutual understanding that a cost pass through event is inconsistent with the factors for consideration but may still be the more efficient mechanism.'

While ActewAGL Distribution considers that the consistency of an event with the considerations concerning the nature and type of event can be clearly identified, it is acknowledged that it is difficult to determine whether passing through the costs of an unforeseeable event would ensure appropriate incentives for service providers to effectively and efficiently manage their risk are maintained. The solution is making this assessment ex-post as part of the cost pass through assessment process rather than ex-ante in determining whether a cost pass through event should be accepted.

This solution is implemented through revisions to the definition of the general cost pass through event in the access arrangement such that the event only occurs where it:

- was not reasonably foreseeable at the time the access arrangement is approved by the AER under the Rules;
- could not have been efficiently and economically insured against on reasonable commercial terms or self-insured, at the time the access arrangement is approved by the AER under the Rules;
- could not have been prevented, nor any increase in costs as a result thereof substantially mitigated, by ActewAGL Distribution using reasonable endeavors; and
- does not fall within any other category of Cost Pass Through Event.

These characteristics ensure that efficient costs arising from an event can only be passed through when event avoidance, mitigation, commercial insurance and self-insurance are unavailable achieving the AEMC's policy intent and an efficient allocation of risk. Further, not only does the AER have the power to accept the event but it is the AEMC's specific policy intent for the AER (in making distribution determinations) to have the flexibility and discretion to ensure that the most efficient mechanism is implemented.

Accepting the cost pass through event achieves the NGO to the greater degree as not only does it ensure appropriate incentives are maintained for service providers to effectively and efficiently manage their risk but also preserves the incentives for service providers to respond appropriately to any unforeseeable events and provides the opportunity to recover at least efficient costs in the long term interests of consumers.

AER draft decision

The AER did not accept the general pass through event as it considered it is difficult to assess whether a prudent service provider could reasonably prevent an event of that nature occurring or substantially mitigate the cost impact of the event. Further, the AER noted that it is also difficult to assess whether a service provider could insure or self-insure against such an event occurring.[174]

The AER considered ActewAGL Distribution's proposal, which prevents the event from being triggered unless it could not have been prevented or substantially mitigated and could not have been efficiently and economically insured against on reasonable commercial terms. The AER considered that this requires an assessment of a largely unlimited range of situations against these criteria on an ex post basis first by ActewAGL and then by the AER after an event has occurred.[175]

ActewAGL Distribution response

We have carefully considered the AER's concerns but do not agree. Evidence from recent regulatory periods has not been that an unlimited range of events require assessment on an ex post basis as to whether they could have been prevented, substantially mitigated or efficiently insured against.

Our experience has been that only a few events required assessment as to whether they satisfy the general cost pass through event. We have also taken a broader look at the various forms of the general cost pass through event over the last round of regulatory resets. We note that there have only been four general cost pass through applications lodged and assessed[176] by the AER despite a form of the general pass through event being in place for about 48 regulatory years[177]. We also note that the two of these applications if made under this revised access arrangement for the 2016/17 - 2020/21 period, would be captured by other cost pass through events or the automatic adjustment factor further lowering the probability of a general cost pass through event application occurring.[178]

This experience shows that the ex post approach to assessing whether a cost pass through event meets the definition of the general cost pass through event is not difficult nor does it require the assessment of a largely unlimited range of situations. Instead past experience suggests that an assessment would only be required once every 24 regulatory years.

---

[174] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, November, p.11-38

[175] AER 2015, *ActewAGL Distribution Access Arrangement 2016-21 Draft Decision, Attachment 11 – Reference tariff variation mechanism*, p.11-38

[176] See SAPN 2013 *Vegetation clearance pass through application,* 11 April; ActewAGL Distribution 2013, *Vegetation management cost pass through,* 1 November; ActewAGL Distribution 2014, *Notification of annual tariff variation and cost pass through events,* 16 April; Ausgrid 2015, *Cost pass through application April 2015 storms*, 21 August

[177] A form of the general cost pass through event was included for distribution determinations for ACT, NSW, SA and QLD initial round of distribution determinations and for the JGN 2010-15, ActewAGL Distribution 2010-15 and Envestra Wagga Wagga access arrangements.

[178] The Ausgrid storms event would be captured under the natural disaster event and the ActewAGL Distribution gas network 2014/15 UNFT costs are captured through the automatic adjustment factor.

As we expect the event to occur with low probability and by definition it cannot occur if the event could have been prevented or substantially mitigated or insured against, the appropriate mechanism to allocate the risk is a cost pass through event.

We consider that this event will, as with all other cost pass through events, ensure network service providers have the regulatory certainty and consequent incentives to efficiently respond to an unexpected event with a material cost impact. Therefore inclusion of the General Pass Through Event is in the long term interests of consumers.

12.3.3 Intra-year tariff variation

In the draft decision the AER rejected our proposal to include in the access arrangement provision for an intra-year tariff variation. The AER says:

> *…we do not consider it prudent or necessary to include provision for intra–year variations to reference tariffs in ActewAGL's access arrangement*

We do not agree with the AER’s conclusion, and maintain our position that allowing intra-year tariff adjustments, in exceptional circumstances and with AER approval, is in consumers’ long term interests.

The AER’s usual approval processes and assessment criteria, ensure that intra-year variations are only approved if they are in consumers’ long term interests.

ActewAGL Distribution’s own considerations of customer impacts and administrative costs would further ensure that applications for intra-year tariff variation would only be made in exceptional circumstances. Over the last 15 years we have rarely sought an intra year tariff variation, due to the additional administration burden on ourselves, the AER, retailers and, most importantly, our consumers.

However, in some cases it is in the long term interests of consumers for an intra year tariff variation to occur, as recognised by the AER.[179] This mechanism enabled us to take action to lower tariffs voluntarily on 1 September 2014 to return carbon costs as soon as possible following the carbon tax repeal, which occurred after the 1 July 2014 tariff variation date. Without the intra-year tariff variation mechanism to make this possible we would not been able to have lower tariffs until 1 July 2016 – almost two years later. We consider this would not be in the long term interests of consumers.

We also note that the AER has approved an intra-year tariff variation provision in JGN’s 2015-20 access arrangement and SP AusNet's 2013–17 access arrangement. It would be inconsistent and unreasonable for the AER to deny ActewAGL Distribution the opportunity to submit an application for an intra-year tariff variation, in exceptional circumstances and in the long term interests of consumers.

Lastly, the need for an intra year tariff variation is heightened in the case that the fixed principle allowing cross period cost recovery of pass through events occurring in the earlier period is not

[179] AER 2015, *Draft decision, Attachment 11, Reference tariff variation mechanism*, November, p. 11-16

approved. As explicitly recognised in clause 6.12 of our 2010-15 access arrangement, if ActewAGL Distribution is not able to defer recovery of a cost pass through amount and there is less than a year left in the access arrangement period, the only way to recover efficient costs is through an intra year tariff variation.

12.3.4 Fixed principle

In our June 2015 submission we proposed a fixed principle to allow the financial impact of an approved cost pass through event that occurs late in the 2016–21 access arrangement period to be addressed in the reference tariffs that apply in the next access arrangement period.

12.3.4.1 AER draft decision

The AER considered that it was not appropriate to establish a fixed principle for the inter-period treatment of cost pass throughs for the 2021-26 period as well as for 2016-21. The AER considered that the inter-period treatment of cost pass throughs in 2021-26 is more appropriately considered as part of its consultation on ActewAGL Distribution's proposals for that period.

12.3.4.2 ActewAGL Distribution response

ActewAGL Distribution has amended its fixed principle, and the associated clause, in order to clarify the specific periods to which the clause applies.

The intention of the fixed principle is to align the cost pass through arrangements in the access arrangement to those specified in the NER. In 2012 the AEMC changed the NER to specifically allow the recovery of costs from cost pass through events which occurred in a previous regulatory control period.[180] This resolved the 'dead zone' issue if a cost pass through amount cannot be recovered solely because the event occurred in the final years of a preceding regulatory period.

We have clarified the clauses make clear that the fixed principle does not constrain the AER's consideration of the cost pass through arrangements applicable in the 2021-26 access arrangement period. Rather the purpose is to allow costs incurred in the 2016-21 period that are to be passed through in accordance with the cost pass through provisions in the 2016-21 access arrangement to be recovered in the 2021-26 period.

Given the purpose of the cost pass through mechanism is to allow for unexpected material changes in costs to be recovered, and thus to provide efficient incentives for network service providers, it is entirely appropriate for a fixed principle to apply. Without a fixed principle the absence of regulatory certainty would undermine the incentives to act efficiently because network service providers could not be sure that costs incurred in acting efficiently in accordance with good industry practice would be recovered.

[180] AEMC 2012, *Rule Determination: National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012,* p.ii Appendix 12.01

This has been recognised by the AEMC which considered that removing the dead-zone issue would achieve the NEO (which is substantively the same as the NGO) to the greatest degree.

We have also added a clause (7.16) to ensure that ActewAGL Distribution can recover costs from any cost pass through event which may occur in 2015/16. The purpose of this clause is to ensure that the costs from any pass through events, such as a natural disaster, which occur after our revision proposal can be recovered. This clause is consistent with the NER and with the clause in the JGN 2016-21 access arrangement.

.

13 Non-tariff components

13.1 AER's draft decision

The draft decision generally accepts the non-tariff components of the access arrangement proposal. The material changes required in the draft decision relate to:

(1) reducing or removing ActewAGL Distribution's discretion under the RSA

(2) removing some of the pre-requisites to the bulk transfer process under the RSA

(3) the treatment of the Molonglo Valley to Phillip primary/secondary In the extensions expansions policy

(4) the timeframe under the extensions expansions policy for the AER to make a decision on whether an expansion or extension is covered.

13.2 ActewAGL Distribution's response and revisions

13.2.1 Revisions accepted by ActewAGL Distribution

ActewAGL Distribution accepts the following required revisions and has amended the access arrangement or RSA to reflect these revisions:

Amendment 12-1: amendment to RSA clause 1.3 to remove ActewAGL Distribution's ability to unilaterally amend the terms and conditions of the RSA to accommodate a Change in Law.

Amendment 12-4: amendment to RSA clause 1.1 to change the definition of "Minimum Network Standards".

Amendment 12-5: amendment to RSA clause 25.2 to correct numbering.

Amendment 12-7: amendment to Access Arrangement clause 9.4 in relation to timing and process for the AER to consider a notification that an extension of expansion will be covered under the extensions/expansions policy.

13.2.2 Revisions partly accepted by ActewAGL

ActewAGL Distribution submits that the following revisions should only be made in part to the access arrangement or RSA and has amended the RSA accordingly:

Amendment 12-2: amendment to RSA clause 32.11 dealing with situation where different standards apply in different jurisdictions.

Amendment 12-3: amendment to RSA to delete pre-requisites for the bulk transfer of sites to a tariff category other than the default tariff category.

ActewAGL's reasons for this are set out in Appendix 13.02 *Outline of Proposed Amendments to the Reference Services Agreement* part of to the revised access arrangement proposal.

13.2.2 Revisions not accepted by ActewAGL Distribution

ActewAGL Distribution has not accepted **Amendment 12-6** which removes from clause 9.1 of the access arrangement the statement that Molonglo Valley to Phillip extension does not represent a high pressure pipeline extension for the purposes of clause 9 of the access arrangement.

ActewAGL Distribution submits that the amendment is not necessary for the following reasons.

1. The only rationale in the draft decision for this amendment is that ActewAGL Distribution's access arrangement proposal *"includes forecast capital expenditure for this extension which suggests that this project be considered a high pressure pipeline extension. We therefore consider the exclusion is no longer appropriate and should be removed"*[181]. However, the draft decision does not address how the fundamental question of whether the project would satisfy the definition of "high pressure pipeline extension" in clause 9.1 of the access arrangement – that is, "an extension to ActewAGL Distribution's Covered Pipeline with a direct connection to a transmission pipeline that provides reticulated gas to a new development or an existing development not serviced with reticulated gas".

2. In its final decision on the proposed 2010 access arrangement, the AER required ActewAGL Distribution to amend the 2010 access arrangement to include the relevant statement the AER now requires be deleted.[182] At that time the AER said:

   > *The AER approves that high pressure extensions required for individual customers within high pressure precincts where no medium pressure mains exist, should be excluded from the general approval requirement attaching to high pressure extensions. However, the AER considers that the definition of high pressure pipeline extensions proposed by ActewAGL in the revised access arrangement proposal must clarify that in-fill pipeline extensions are not included and that the focus concerning high pressure pipelines is on new developments and existing developments that have not previously been serviced with reticulated gas.* ***Clause 7.1 [now clause 9.1] also needs to clarify that the anticipated extension in the Australian Capital Territory from Belconnen across the Molonglo Valley to Phillip does not represent a high pressure extension for the purposes of Part 7 of the access arrangement proposal*** *[our emphasis].*[183]

   The only rationale in the draft decision for this amendment (set out in paragraph 1 above) does not support the AER's change of view.

[181] Draft Decision, section 12.3.4 page 12-22

[182] Final Decision, March 2010, page 128

[183] Final Decision, March 2010, pages 127-128

13.2.3 Other revisions made to access arrangement

In addition to the revisions discussed at sections 13.2.1 and 13.2.3, ActewAGL Distribution has made the other non-tariff revisions to the access arrangement as set out in appendix 13.01.

.

14 Demand

14.1 Introduction

This chapter sets out ActewAGL Distribution's response to the AER's draft decision on forecasts of gas consumption and customer numbers (collectively referred to as ActewAGL Distribution's demand forecasts) for each customer class over the 2016-21 access arrangement period.

Forecast demand is an important input into the derivation of ActewAGL Distribution's forecast opex and capex as well as the reference tariffs. Establishing the best, reasonably-based demand forecasts in the circumstances is critical to afford ActewAGL Distribution a reasonable opportunity to recover at least its efficient costs and thereby supports our ability to deliver the safe and reliable gas service our customers expect.

ActewAGL Distribution engaged the Core Energy Group (Core Energy) to develop the demand forecasts set out in our June 2015 submission. Core Energy's forecasting approach was based on the principles applied by the Australian Energy Market Operator (AEMO) and in recent decisions made by the AER. Core Energy was selected to produce these forecasts as it has considerable expertise and experience in developing gas network forecasts and advising on gas forecasting methods.[184]

Forecasts were developed for two customer groups: the volume customer group (or Tariff V forecasts) and the demand customer group (or Tariff D forecasts). The demand forecasts in our June 2015 submission showed a continuation of the recent trend of declining average consumption per connection and a slowing in connection growth.

In the draft decision the AER has approved aspects of ActewAGL Distribution's proposed demand forecasts including the Tariff D demand forecasts. The AER has not accepted other aspects of ActewAGL Distribution's proposed demand forecasts including the Tariff V forecast consumption per connection and connection forecasts for residential and commercial customers.

As outlined in Section14.3, whilst ActewAGL Distribution does not necessarily agree with the AER's revised forecasting approach, we have accepted all aspects of the resultant forecasts as outlined in the draft decision aside from the connection forecasts for residential medium density and high rise dwellings. ActewAGL Distribution considers that the gas penetration rate of 36 per cent used by the AER in the draft decision for medium density and high rise dwellings is likely to materially understate the penetration rate in connections for residential medium density and high rise dwellings over the 2016-21 access arrangement period. ActewAGL Distribution has adopted a revised penetration rate of 72 per cent, based on historical connections data over the period2010/11 to 2013/14, to update the connections medium density and high rise forecasts in

[184] This experience includes, but is not limited to, developing the gas consumption forecasts for the Jemena Gas Networks (JGN) 2015-20 access arrangement, the Envestra (South Australia) 2011-2016 access arrangement, the Envestra (Victoria) 2013-17 access arrangement and the Envestra (Queensland) 2011-16 access arrangement.

our January 2016 submission. ActewAGL Distribution considers the resulting revised Tariff V connection forecast and resultant demand forecast to reflect the best, reasonably-based forecast of demand over 2016-21 access arrangement period.

14.2 AER's draft decision

The AER reviewed ActewAGL Distribution's demand forecasts against the criteria set out in clause 74(2) of the National Gas Rules (Rules), which requires that forecasts and estimates are:[185]

- arrived at on a reasonable basis; and
- represent the best forecast or estimate possible in the circumstances.

As outlined in Table 14.1, the AER has:

- accepted the Tariff D forecast connection numbers and Maximum Daily Quantity (MDQ); but
- not accepted the Tariff V forecast connection numbers or forecast consumption per connection for residential and commercial customers and developed alternative demand forecasts that the AER considers comply with the Rules.[186]

With respect to connection forecasts for residential customers, the AER stated that:

> *"…..our main concern is with Core Energy's methodology and the assumptions it has made to derive new dwellings (new residential connections)…*
>
> *We note that the 90 per cent connection rate is not based on historical connections…We consider that the this method overestimates the penetration rate"* [187]

With respect to consumption per connection forecasts, the AER stated that:

> *"…..ActewAGL Distribution applies the average annual growth rate of -3.57 per cent to each of the new residential customer types.*
>
> *We consider that applying this overall declining rate to each individual residential connection type has the effect of double counting the reduction in gas consumption at the total residential customer level."*[188]

---

[185] National Gas Rules, Rule 72(2).

[186] AER 2015, *Attachment 13 – Demand, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 21.

[187] AER 2015, Attachment 13 – Demand, Draft decision: ActewAGL Distribution access arrangement 2016-21, November, p. 12.

[188] AER 2015, Attachment 13 – Demand, Draft decision: ActewAGL Distribution access arrangement 2016-21, November, p. 17.

The AER expresses similar concerns in relation to average commercial consumption.

This led the AER to:

- Conclude that ActewAGL Distribution's demand forecasts for were not the best estimates in the circumstances
- Develop alternative demand forecasts that they consider addresses these concerns and comply with the Rules.
- Use these alternative demand forecasts in this draft decision. [189]

The AER's draft decision is summarised in Table 14.1.

Table 14.1 AER draft decision on ActewAGL Distribution's demand forecasts

Aspect of demand forecast	AER draft decision	AER comment
Connection numbers		
Tariff V Residential	Reject AAD proposal	Not consistent with NGR 74(2)
Tariff V Commercial	Reject AAD proposal	Not consistent with NGR 74(2)
Tariff D	Accept AAD proposal	Consistent with NGR 74(2)
Consumption per connection		
Tariff V Residential	Reject AAD proposal	Not consistent with NGR 74(2)
Tariff V Commercial	Reject AAD proposal	Not consistent with NGR 74(2)
Tariff D	Accept AAD proposal	Consistent with NGR 74(2)

14.3 ActewAGL Distribution's response and revisions

ActewAGL Distribution acknowledges that the AER has accepted many aspects of our proposed methodology as likely to deliver demand forecasts that satisfy rule 74(2). This reflects that the approach applied by Core Energy was largely consistent with that used by AEMO and generally accepted by the AER in previous decisions.

ActewAGL Distribution recognises the AER's concerns with Core Energy's approach to forecasting Tariff V connections over the 2016-21 access arrangement period and has carefully examined historical information on gas connections and other publicly available information to establish an understanding of gas penetration rates across Tariff V market segments.

ActewAGL Distribution does not agree that the revised approach applied by the AER leads to better forecasts of connections, nor does ActewAGL Distribution agree with the submissions

[189] AER 2015, *Attachment 13 – Demand, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 21.

made by the Alternative Technology Association that suggest that gas is no longer competitive in the ACT.[190]

However ActewAGL Distribution has decided to accept the connection forecasts for Tariff V, aside from connections for residential medium density and high rise dwellings.

We believe that the gas penetration rate of 36 per cent used by the AER for medium density and high rise dwellings is not the best, reasonably-based estimate in the circumstances, because it materially understates the expected penetration rate in connections for residential medium density and high rise dwellings over the 2016-21 access arrangement period. Further detail is provided in section 14.3.1. Given that forecast demand is an important input into the derivation of ActewAGL Distribution forecast operating expenditure and capital expenditure as well the reference tariffs, establishing the best, reasonably-based demand forecasts in the circumstances is critical to afford ActewAGL Distribution a reasonable opportunity to recover at least its efficient costs and thereby supports our ability to deliver the safe and reliable gas service our customers expect.

While ActewAGL Distribution recognises the AER's concerns with Core Energy's approach to forecasting consumption per connection, we do not agree that the revised approach applied by the AER necessarily leads to better forecasts of demand. This reflects our concern that the revised approach does not address the increasing proportion of more energy efficient households (partly in response to increasing wholesale gas prices) and the changing housing stock mix (in particular the growing preference for medium density and high rise dwellings).

Despite our concerns with the AER's revised approach, ActewAGL Distribution has decided to accept all aspects of the forecast consumption per connection for Tariff D and Tariff V customers as it is likely to provide the business with a reasonable opportunity to recover its efficient costs over the 2016-21 access arrangement period.

Our response to the AER's draft decision is summarised in Table 14.2, and is to:

- Accept all aspects of the forecast consumption per connection for Tariff D and Tariff V customers
- Accept the connection forecasts for Tariff D and Tariff V, aside from residential connections for medium density and high rise dwellings
- Develop a revised forecast for Tariff V connections for residential medium density and high rise dwellings using a gas penetration rate of 72 per cent (compared to the assumption of 36 per cent used by the AER in the draft decision). Further detail is provided in Section 14.3.1.

[190] ATA notes that "It is no longer economic for any new home, or existing all-electric home, located anywhere in the ACT (or indeed anywhere in Australia), to connect to mains or bottled gas – as compared with installing and operating efficient electric appliance alternatives." Alternative Technology Association, Submission to the AER on ActewAGL's Access Arrangement Proposal, August 2015, p1.

- Develop revised Tariff V demand forecasts for the purposes of the January 2016 submission that reflects the best, reasonably-based demand forecasts realistic over the 2016-21 access arrangement period. Further detail is provided in Section 14.3.2.

Table 14.2 Summary of ActewAGL Distribution's response to the AER draft decision demand forecasts

Aspect of demand forecast	AER Draft Decision	AAD response	AAD comment
Connection numbers			
Tariff V Residential	Reject AAD proposal	Do not accept draft decision	AAD does not accept that a gas penetration rate of 36% reflects historical information, and considers that as a result, the AER residential connection forecast is likely to materially understate the growth in residential connections for medium density and high rise dwellings over the access arrangement period.
Tariff V Commercial	Reject AAD proposal	Accept draft decision	While AAD does not accept the revised approach will necessarily lead to better demand forecasts, AAD considers the AER Draft Decision provides for a reasonable opportunity to recover efficient costs over the next AA period.
Tariff D	Accept AAD proposal	Accept draft decision	No comment
Consumption per connection			
Tariff V Residential	Reject AAD proposal	Accept draft decision	While AAD does not accept the revised approach will necessarily lead to better demand forecasts, AAD considers the AER Draft Decision provides for a reasonable opportunity to recover efficient costs over the next AA period.
Tariff V Commercial	Reject AAD proposal	Accept draft decision	
Tariff D	Accept AAD proposal	Accept draft decision	No comment

14.3.1 Residential connection growth

Forecast connection growth (and resultant demand forecasts) are an important input into the derivation of ActewAGL Distribution forecast operating expenditure and capital expenditure as well the reference tariffs. Establishing the best, reasonably-based demand forecasts in the circumstances is critical to afford ActewAGL Distribution a reasonable opportunity to recover at least its efficient costs and thereby supports our ability to deliver the safe and reliable gas service our customers expect. This is in the long-term interests of our consumers.

The AER did not accept the Tariff V forecast connection numbers and developed alternative demand forecasts that the AER considers comply with the Rules.[191] In developing the alternative residential connection forecast for medium density and high rise dwellings and resultant demand forecast the AER used a gas penetration rate of 36 per cent[192], and an overall residential gas penetration rate of 62 per cent[193]. In making this decision the AER refers to historical information as well as ABS survey data.[194]

ActewAGL Distribution does not accept that a gas penetration rate of 36 per cent reflects historical information on new gas connections for medium density and high rise dwellings across the our network.

As Table 14.3 highlights, there were 8,244 new medium density and high rise dwellings connected to ActewAGL Distribution's network over the 2010/11 to 2013/14 period, including those customers using gas for hot water as part of a centralised hot water system. ActewAGL Distribution has calculated this figure based on unique gas Delivery Point Identifiers (DPI) over the 2010/11 to 2013/14 period. A DPI represents a meter or grouping of meters at a street address. Each DPI is subject to competition between retailers. In some instances a particular street address may have:

- a single DPI with a gas meter, or a hot water meter, linked to it
- a single DPI with more than one gas or hot water meter linked to it, or
- more than one DPI, for example a high-rise apartment with individual gas and hot water meters that allows customers to choose their gas retailers and participate in the competitive retail gas market.

Comparing this to the forecast of 11,390 new medium density and high rise dwellings across the ACT only over the 2010/11 to 2013/14 period, this represents a gas penetration rate of 72 per cent.[195]

---

[191] AER 2015, *Attachment 13 – Demand, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 21.

[192] Refer cell J23 on sheet "Assumptions" in the AER's demand forecast model.

[193] The average of 62% is derived from the penetration rate of 36% for medium density and high rise dwellings, and 103% for new estates.

[194] AER 2015, *Attachment 13 – Demand, Draft decision: ActewAGL Distribution access arrangement 2016-21*, November, p. 13.

[195] The figure of 8,244 represents medium density and high rise dwellings gas or hot water connections across the ActewAGL Distribution's network (incl. Queanbeyan and Palerang). The figure of 11,390 represents medium density dwellings across the ACT only. The figure of 72% is therefore on a consistent basis to the 36% used by the AER in its draft decision, and appropriate to apply to a forecast of new medium density and high rise dwellings.

Table 14.3 Historical information on new gas DPIs in medium density and high rise dwellings, 2010/11 to 2013/14

	2010/11	2011/12	2012/13	2013/14	Total
New gas DPIs in medium density and high rise dwellings	1,553	1,752	2,722	2,217	8,244

For this reason the AER's residential connection forecast is likely to materially understate the growth in residential connections for medium density and high rise dwellings over the access arrangement period.

In developing a revised forecast for Tariff V residential connections for medium density and high rise dwellings, ActewAGL Distribution has:

- used a gas penetration rate of 72 per cent (compared to the assumption of 36 per cent used by the AER in the draft decision), which recognises that ActewAGL Distribution is likely to connect new medium density and high rise dwellings in line with the historical penetration rate; and
- substituted this figure in cell J23 on sheet "Assumptions" in the AER's demand forecast model to forecast new medium density and high rise dwelling connections of 6,265 over the access arrangement period.[196]

An overview of the forecast Tariff V new connections is summarised in Table 14.4.

Table 14.4 Forecast new connections by volume market type

	2016/17	2017/18	2018/19	2019/20	2020/21
Electricity to gas (E to G)	768	768	768	768	768
New estates	2,073	1,988	1,936	1,936	1,796
New medium density and high rise	1,066	1,280	1,330	1,330	1,260
Small business	84	126	129	132	136

[196] Cell J24 on the "Assumptions" sheet contains an average residential penetration rate, considering both new estates (left unchanged) and new medium density and high rise dwellings connections (updated to 72 per cent). AAD has not updated this average value to reflect the higher medium density and high rise dwelling penetration rate. Cell J24 contains a residential penetration rate of 62 per cent which is exclusively used to estimate the number of disconnections and new connections resulting from the Mr Fluffy developments. This assumption has been derived with a numerator based on the ActewAGL Distribution area (ACT, Palerang and Queanbeyan), and a denominator based only on the ACT. The inconsistent basis of the penetration rate is necessary to scale the HIA housing forecast for the ACT to the ActewAGL Distribution area, but is inconsistent when applied to the Mr Fluffy developments.

14.3.2 Summary of revised Tariff V demand forecast

As noted in section 1.3.1, in developing a revised Tariff V demand forecast for the 2016-21 access arrangement proposal we have not made any revisions to other aspects of the draft decision (aside from that set out in section 14.3.1).

Tariff D demand forecasts are consistent with those outlined in the AER draft decision[197].

Table 14.5 and Table 14.6 set out ActewAGL's Distribution revised forecast customer numbers, and annual consumption by customer type.

Table 14.5 Forecast customer numbers by customer type

	2016/17	2017/18	2018/19	2019/20	2020/21
Total volume market	143,146	146,310	149,459	152,806	155,927
Total demand market	40	40	40	40	40
Total customers	**143,186**	**146,350**	**149,499**	**152,846**	**155,967**

Table 14.6 Forecast annual consumption by customer type (TJ)

	2016/17	2017/18	2018/19	2019/20	2020/21
Total volume market	6,299	6,175	6,064	5,986	5,922
Total demand market	1,185	1,186	1,231	1,232	1,232
Total consumption	**7,485**	**7,360**	**7,296**	**7,218**	**7,154**

197 See: AER 2015, *Attachment 13 – Demand | Draft decision: ActewAGL Distribution Access Arrangement 2016-21,, Table 13.1 and 13.2* November

List of appendices

Chapter	Appendices
2. Overview	2.01 Checklist of responses to required revisions all to check 2.02 Interrelationships between draft decision elements
4. Capital base and depreciation	4.01 Roll forward model
5. Rate of return, gamma and inflation	5.01 Detailed response to rate of return, gamma and inflation 5.02 Alternative debt averaging periods (confidential) 5.03 Expert Report by CEG: *Critique of AER's approach to transition*. 5.04 Expert report by CEG: *Criteria for assessing fair value curves*. 5.05 Expert report by HoustonKemp: *Cost of Equity, Response to the AER's Draft Decision*. 5.06 Expert report by Frontier Economics: *The relationship between government bond yields and the market risk premium*. 5.07 Expert report by Frontier Economics: *The required return on equity under a foundation model approach*. 5.08 Expert report by Frontier Economics: *Estimating the equity beta for the benchmark efficient entity.* 5.09 Expert report by Frontier Economics: *The appropriate use of tax statistics when estimating gamma.* 5.10 Memo by CEG: *Cost of debt and inflation forecasts*.

Chapter	Appendices
6. Capital expenditure	6.01.01 Capex forecast Model (confidential) 6.01.02 Market Expansion Unit Rates Model (Confidential) 6.01.03 Stay in business meter replacement unit rate model (Confidential) 6.02 HIA Forecasts by Dwelling Type ACT May 2015 (Confidential) 6.03 Capacity development presentation 6.04 Canberra Spatial Plan 6.05.01 Bungendore Holistic Audit (Confidential) 6.05.01 Gungahlin Holistic audit (Confidential) 6.05.01 Hoskinstown Holistic Audit (Confidential) 6.05.01 Watson Holistic Audit (Confidential) 6.06 ACT Facilities Compliance program updated estimate (Confidential) 6.07 Hot water meters approach (Confidential)
7. Operating expenditure	7.01 Opex model 7.02 Hoskinstown operations and maintenance contract costs base year adjustment (confidential)
9. Efficiency carryover mechanism	9.01 Expert report by HoustonKemp, Efficiency carryover mechanism. 9.02 Proposed efficiency carry over mechanism model
10. Revenue requirement and price path	10.01 Post tax revenue model

Chapter	Appendices
12. Reference tariff variation mechanism	12.01 AEMC 2012, National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012 Rule Determination 12.02 AEMC 2006, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006) no.18* 12.03 JGN 2015, *Response to the AER's draft decision & revised proposal* 12.04 ActewAGL Distribution 2015, *Revised Regulatory Proposal 2015-19,* January 12.05 The Treasury 2015, *Economic round up,* Issue 1 12.06 Attorney-General's Department 2006, *Available and affordable – Improvements in liability insurance following tort law reform in Australia* 12.07 Commonwealth of Australia 2009, *Cyber Security Strategy* 12.08 Australian Cyber Security Centre 2015, *2015 Threat Report* 12.09 ABC News report (online), C*hina blamed for massive cyber attack on Bureau of Meteorology computer*, 12.10 ABC News report (online), *Classified report on Bureau of Meteorology cyber attack recommends computer system overhaul* 12.11 AER 2015, *JGN Access Arrangement 2015-20 Final Decision, Attachment 11 – Reference tariff variation mechanism* 12.12 AER 2015, *Final Decision ActewAGL Distribution Determination: ActewAGL Distribution Determination:* Attachment 15, April
13. Non-tariff components	13.01 Table of amendments to the AA 13.02 Table of amendments to the RSA

Abbreviations used in this document

Abbreviation	Full term
AAD	ActewAGL Distribution
ACT	Australian Capital Territory
ACompT	Australian Competition Tribunal
AEMC	Australian energy Market Commission
AER	Australian Energy Regulator
ARORO	Allowed rate of return objective
CAM	cost allocation method
capex	capital expenditure
CPI	Consumer price index
DAMS	Distribution Asset Management Services Agreement
ECM	Efficiency carryover mechanism
ECRC	Energy consumer reference council
EGP	Eastern gas pipeline
EIL	Energy Industry Levy
IT	information technology
JAM	Jemena Asset Management Pty Ltd
JGN	Jemena Gas Networks (NSW) Ltd
kPa	kilopascal(s)
m	metre(s) / millions (when relating to financial information)
NGL	National gas law
NGO	National gas objective
NSW	New South Wales
O&M	operations and maintenance
opex	operating and maintenance expenditure
PJ	Peta joules or 10^{12} joules
RBA	Reserve Bank of Australia
RIN	Regulatory Information Notice
RSA	Reference service agreement
Rules, the, NGR	National Gas Rules
SL CAPM	Sharpe-Lintner capital asset pricing model
TJ	Terra joules or 10^{15} joules
UAG	unaccounted-for gas
UNFT	Utilities Network Facilities Tax
ZNX(2)	ZNX (2) Pty Ltd