Attachment 8.9

Response to Draft Decision: Capital Expenditure

2016/17 to 2020/21 Access Arrangement Information Response to Draft Decision

Australian Gas Networks

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1 Response to Draft Decision on Capital Expenditure

1.1 Introduction

This attachment sets out Australian Gas Networks Limited's (AGN's) response to the Australian Energy Regulator's (AER's) Draft Decision on capital expenditure (capex) over the next (2016/17 to 2020/21) Access Arrangement (AA) period.

AGN's proposed capex program provides the funding required to satisfy the forecast growth in demand for services, to maintain and improve safety, to maintain system integrity and to comply with all regulatory obligations that govern the safe and reliable supply of natural gas. Importantly, it was informed by AGN's stakeholder engagement program and underpinned by a range of network plans, such as the Asset Management Plan, Mains Replacement Plan, Capacity Management Plan and Information Technology Plan.

The AER has accepted elements of AGN's proposed capex (such as meter replacement, telemetry, general growth, non-distribution system expenditure and contributions), but has modified or rejected a large portion of the capex program primarily on the basis that additional information is required to be provided from AGN before it can be approved. This is particularly evident with respect to AGN's proposed mains replacement program, which was reduced in the AER's Draft Decision by 55% to $168 million.

In total, the Draft Decision provides AGN with total net capex over the next AA period of $393 million, which is 43% less than AGN's proposed capex and 17% less than that expected to be incurred over the current (2011/12 to 2015/16) AA period.

As outlined in Section 1.3, AGN has provided in this response, and associated attachments, the additional information required by the AER to demonstrate that the proposed capex conforms to the relevant criteria in the National Gas Rules (NGR). This is particularly the case in respect of our proposed mains replacement program, which is integral to maintaining public and employee safety.

Unless otherwise stated, the forecast expenditure detailed in this Attachment is expressed in 2014/15 dollar terms before the application of escalators and overheads.

1.2 AER Draft Decision

The AER assessed AGN's capex proposal against Rule 79(1) of the NGR, which requires capex to be prudent and efficient and to be justifiable on a ground set out in Rule 79(2). The AER also had regard to Rule 74, which requires any forecasts to be arrived at on a reasonable basis and to reflect the best estimate in the circumstances.

The AER's Draft Decision provides AGN with total net capex over the next AA period of $393 million, which is 43% less than AGN's proposed capex. Importantly, the AER notes that a large portion of the capex reduction is due to insufficient information being provided by AGN to enable the AER to approve the proposed expenditure:

> *"Much of this reduction is because we did not have sufficient information to find the proposed expenditures to be prudent or efficient. We have identified where further information needs to be provided by AGN in order for us to be satisfied that the proposed expenditures meets the NGR."*[1]

[1] AER 2015, "*Attachment 6 – Capital Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 6-7.

The majority of the reduction in AGN's proposed capex is attributable to the AER's Draft Decision on mains replacement. Of the $370 million proposed by AGN for mains replacement, only $168 million was approved by the AER[2] on the basis that further risk analysis is required:

> *"AGN has not provided evidence in the form of a rigorous (quantitative) risk assessment to demonstrate that the proposed capex is conforming capex over the 2016–21 access arrangement period that complies with rule 79."* [3]

Table 1.1 summarises the AER's Draft Decision for each element of AGN's capex proposal.

TABLE 1.1: SUMMARY OF AER'S DRAFT DECISION ON CAPEX

	AER Draft Decision	AER Comment
Mains Replacement	Modify AGN Proposal	AGN's proposed mains replacement program was reduced on the basis that the AER considered the program was not underpinned by a rigorous risk assessment.
Meter Replacement	Accept AGN Proposal	Accepted AGN proposal as compliant with Rule 79.
Augmentation	Modify AGN Proposal	• Accepted four initiatives (SA14, SA15, SA17 and SA19) as compliant with Rule 79; accepted SA21a as operating expenditure (opex). • Rejected SA21 on the basis that the pipelines in question are still fit for purpose. • Rejected SA71 on the basis that demand growth in the next AA period could be met by increasing the pipeline pressure.
Telemetry	Accept AGN Proposal	Accepted AGN proposal (SA01) as compliant with Rule 79.
Regulators and Valves	Modify AGN Proposal	• Accepted six initiatives (SA08, SA22, SA33, SA34, SA45 and SA70) as compliant with Rule 79; accepted SA09 as opex. • Rejected SA75 on the basis costs are site-specific and should be borne by the individual customer.
IT	Modify AGN Proposal	• Accepted five initiatives (SA57, SA58, SA62, SA82 and SA84) as compliant with Rule 79. • Rejected SA59 and SA60 on the basis the work is discretionary, does not have a positive Net Present Value (NPV) and no deficiencies with the current processes have been identified. • Rejected SA64 on the basis costs are site-specific and should be borne by the individual customer. • Rejected SA65 on the basis no specific need has been identified and material costs could be recovered by AGN through the cost pass through mechanism.
Growth Assets	Modify AGN Proposal	• Rejected SA24 on the basis of inconsistent demand and revenue assumptions and the standard life assumed for industrial and commercial connections. • Accepted AGN's general growth assumptions but removed connections associated with SA24 to maintain consistency.
Other Distribution System	Modify AGN Proposal	• Accepted five initiatives (SA06, SA36, SA37, SA49 and SA53) as compliant with Rule 79; accepted SA32 as opex. • Modified SA10, SA28 and SA31 to reflect different work volumes. • Rejected SA52 on the basis there was no cost benefit analysis.
Other Non-Distribution System	Accept AGN Proposal	Accepted three initiatives (SA30, SA56 and SA69) as compliant with Rule 79.
Unit Rates	Modify AGN Proposal	Accepted non-mains replacement unit rates; modified mains replacement unit rates.

[2] AER 2015, "*Attachment 6 – Capital Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 6-28.

[3] Ibid, pg. 6-9.

Escalation	Modify AGN Proposal	• Accepted AGN's escalation methodology, with the exception of the escalators applied to the new estate connections capex category. • Applied forecast escalation contained within AGN's current contracts to the new estate connections capex category forecast.
Overheads	Reject AGN Proposal	• Rejected AGN's proposed approach to calculating overheads as a flat percentage of capex. • Applied an overhead calculation derived from fixed and variable portions of total capex programs.
Contributions	Accept AGN Proposal	AGN's proposal is the best estimate in the circumstances.

1.3 AGN Response to Draft Decision

AGN has provided the additional information requested by the AER in order to demonstrate that the proposed capex complies with Rule 79. As outlined in Table 1.2, AGN has provided the requested information in response to the Draft Decision for several key initiatives, most notably in relation to our proposed mains replacement program.

TABLE 1.2: SUMMARY OF AGN'S RESPONSE TO THE AER DRAFT DECISION ON CAPEX

	AER Draft Decision	AGN Response	AGN Comment
Mains Replacement	Modify AGN Proposal	Respond to Draft Decision	AGN is committed to pursuing its mains replacement program over the next AA period in order to maintain and improve safety on the South Australian natural gas distribution network (the Network). Specifically, AGN has provided further risk assessment and quantitative modelling supporting the prioritisation of mains replacement capital works.
Meter Replacement	Accept AGN Proposal	Accept Draft Decision	No comment.
Augmentation	Modify AGN Proposal	Respond to Draft Decision	AGN does not accept the AER's decision for initiatives SA21 and SA71. AGN has clarified its original Business Cases to more clearly explain the drivers for these initiatives.
Telemetry	Accept AGN Proposal	Accept Draft Decision	No comment.
Regulators	Modify AGN Proposal	Respond to Draft Decision	Although SA75 received some support from stakeholders during the engagement program, AGN accepts the AER's position that this is a site specific cost. AGN does not accept the reclassification of SA09 as opex, given expert advice that this is a capex project.
IT	Modify AGN Proposal	Respond to Draft Decision	AGN does not accept the AER's decision for SA59 and SA60. Our response provides additional information in support of the basis for this expenditure.
Growth Assets	Modify AGN Proposal	Respond to Draft Decision	AGN does not accept the AER's decision for the Two Wells project (SA24). AGN's response addresses concerns raised around the assumptions and demonstrates that the project delivers a positive NPV for this extension. AGN has included an additional Business Case relating to the expansion of the network to Mount Barker (SA25). AGN has also reproposed its Significant Extension Event Cost Pass Through, should the AER not accept the proposed capex in relation to this key network extension.

Other Distribution System	Modify AGN Proposal	Respond to Draft Decision	AGN does not accept the AER's Draft Decision for SA52. This initiative has been re-proposed and now includes more detail on the costs and benefits as required by the AER. AGN does not agree with the modification made by the AER with respect to SA10 and SA31 and has modified the original Business Cases to reflect updated information and feedback from the AER. Whilst AGN is confident that the volumes originally proposed in SA28 can be achieved, we have accepted the AER's Draft Decision to modify these volumes.
Other Non-Distribution System	Accept AGN Proposal	Accept Draft Decision	No comment.
Unit Rates	Modify AGN Proposal	Respond to Draft Decision	AGN does not consider the AER Draft Decision incorporated most recent information and has adjusted unit rates accordingly.
Escalation	Modify AGN Proposal	Respond to Draft Decision	AGN accepts that where forecast escalation in AGN's current contracts applies during the next AA period, this should be applied to the relevant contract costs until their expiry. However, since these contracts expire in 2017 and 2018, AGN has applied the standard escalators beyond 1 July 2018.
Overheads	Reject AGN Proposal	Accept Draft Decision	AGN accepts the AER's proposed methodology and has applied it to the revised capex forecast.
Contributions	Accept AGN Proposal	Accept Draft Decision	No comment.

Further detail on key elements of our response follows in the remainder of the attachment.

1.3.1 Mains Replacement

The provision of a safe and reliable supply of natural gas is the most important driver of AGN's business performance. A key part of ensuring public safety is our mains replacement program, which sets out the strategy for the replacement of ageing/deteriorating mains on the Network and subsequently reducing network risk. Importantly, we have demonstrated a strong commitment to delivering our mains replacement program, undertaking 1,152 kilometres of mains replacement during the current AA period, 80 kilometres above the benchmarks set by the AER.

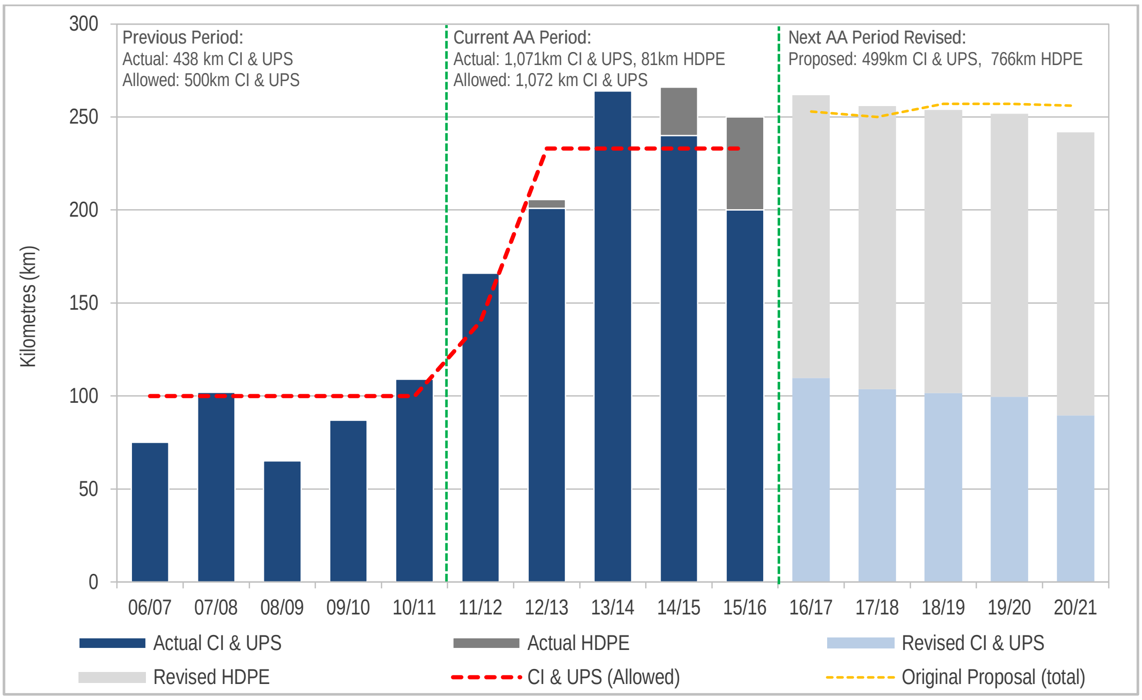
Given the importance of mains replacement, it is unsurprising that the delivery of our mains replacement plan was one of the key elements of our Initial AA Proposal, which provided for the replacement of 1,273 kilometres of mains and accounted for 60% of the total forecast capex. As outlined in Section 1.3.1.1, however, the AER did not accept our proposed mains replacement program on the basis that it did not have enough information to validate that the proposed capex complied with Rule 79 of the NGR.

In response to the AER's Draft Decision, we have taken the opportunity to review our proposal, and submit the further information requested by the AER to support AGN's mains replacement program. This information includes a rigorous risk assessment that considers the likelihood of these assets causing harm and a cost impact analysis that identifies the net present cost to customers of various rates of mains replacement, as well as the average cost per customer per year compared to the AER's alternative proposal . We have also presented further analysis on the emerging risk associated with high density polyethylene (HDPE) mains, including quantitative modelling that prioritises asset replacement across the Network.

Section 1.3.1.2 summarises AGN's response to the Draft Decision, and our Revised AA Proposal that 1,265 kilometres of mains to be replaced during the next AA period is prudent and efficient. As shown in Figure 1.1, the volumes of mains replacement proposed for the next AA period are consistent with our July 2015 submission, however, the composition of this program has been revised to reflect further analysis undertaken since submission of our Initial AA Proposal and following the Draft Decision.

This, combined with revisions to our proposed mains replacement unit rates (see Section 1.3.7), has resulted in the proposed cost of the program over the next AA period falling to $326 million, which is 12% less than our Initial AA Proposal (of $370 million). The decrease in forecast mains replacement capex is primarily due to lower unit rates over the period, which have been adjusted to reflect the latest information and recent tendering processes that have been conducted since we submitted our Initial AA Proposal.

FIGURE 1.1: MAINS REPLACEMENT 2006/07 TO 2020/21



Further detail on our revised mains replacement program is provided in the remainder of this Section and in Attachment 8.10.

1.3.1.1 AER Draft Decision on Mains Replacement

The AER's Draft Decision recognised the hazard associated with the mains currently in the Network, however it questioned the likelihood and impact of a major hazard occurring:

> *"The information that AGN has provided us does not support or demonstrate that its proposal is prudent or efficient. In particular, AGN did not provide a rigorous (quantitative) risk assessment to establish that its proposed rate of mains replacement over the 2016–21 period is prudent and efficient. Rather, its assessment identifies what it terms 'hazards' and proceeds on the basis that they will occur and have significant impacts. We consider a rigorous risk assessment that measures the likelihood and impact of a hazard occurring is necessary in determining whether proposed investment is prudent and efficient. This is especially the case where, as here, there are no regulatory or legislative obligations that require AGN to replace mains at the rate it has proposed over the 2016–21 period."*[4]

And:

[4] AER 2015, "*Confidential Appendix A - Attachment 6: Capital expenditure, Draft decision: Australian Gas Networks Access Arrangement 2016–21",* pg. 6A-6.

> *"We consider a rigorous risk assessment that measures the likelihood and impact of a hazard occurring is necessary in determining whether proposed investment is prudent and efficient."*[5]

The AER did, however, invite AGN to provide additional information to support its proposed mains replacement program. Specifically, the AER states:

> *"We invite AGN in its revised proposal to … include the necessary material, particularly a rigorous risk assessment, to demonstrate and justify the extent to which its proposed capex for mains replacement is conforming capex that complies with rule 79"*[6]

Further, the AER also considers:

> *"…ideally, we would derive an alternative estimate based on a cost benefit analysis. This information is not available to us, and we accept that this kind of analysis may be difficult to undertake. Given the limited information available to us, we have drawn on historical leakage reduction rates."* [7]

The AER stated that, without a clearly expressed risk assessment and cost benefit analysis, its ability to develop an alternative mains replacement program was limited. The AER scaled AGN's proposed volume of mains replacement down based on an assumed leak reduction target, resulting in a Draft Decision allowance of 577 kilometres of mains replacement and capex of $168 million over the next AA period. The Draft Decision is equivalent to a:

- 55% cut to the volume of high risk mains proposed to be replaced over the next AA period; and a
- 50% cut to the volume of high risk mains replaced over the current AA period.

1.3.1.2 AGN Response to the AER's Draft Decision on Mains Replacement

In response to the AER's Draft Decision, we have provided information as requested by the AER to support our mains replacement program. More specifically, AGN submits that:

- AGN is in fact required by regulatory and legislative obligations to replace at risk mains;[8]
- a rigorous risk assessment informs the proposed rate of mains replacement over the next AA period; more specifically this analysis has identified 2,619 kilometres of at risk[9] mains to be replaced as soon as practicable;
    - of this 2,619 kilometres, over the next AA period, AGN proposes to replace 1,265 kilometres of the highest risk mains based on risk prioritisation modelling and an assessment of deliverability and cost to customer; and that

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5 AER 2015, "*Attachment 6: Capital expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016–21*", November 2015, pg. 6-29.

6 Ibid, pg. 6-37.

7 Ibid.

8 In its Draft Decision (pg. 6A-6 of Confidential Appendix A – Attachment), the AER state that *"This is especially the case where, as here, there are no regulatory or legislative obligations that require AGN to replace mains at the rate it has proposed over the 2016–21 period.*"

9 'At risk' mains comprise Cast Iron and Unprotected Steel mains, HDPE Class 250 and HDPE Class 575 mains in the network, whose risk rating under AS/NZS 4645 ranges from 'High' to 'Extreme'.

  - replacing in the order of 1,265 kilometres of mains over the next AA period reflects a sustainable and efficient rate of replacement that is consistent with AGN's delivery capability and satisfies AGN's obligation to reduce the inherent network risk to low or if this is not possible, as low as reasonably practicable.

- while the AER's proposal would increase the price reduction by around $7.90 per customer per year over the next AA period relative to AGN's proposal (resulting in an overall price reduction of $123.80 in 2016/17)[10], it would leave more than 2,000 kilometres of at risk mains in the Network. To this extent, AGN notes that;

  - the net present cost difference between the AGN mains replacement plan and an indicative AER replacement scenario is $3.45 per customer per annum over the 60 year useful life of the assets; and

  - the AER's alternative mains replacement proposal has not been arrived at on a reasonable basis, and is not the best estimate as required by NGR 74.

- AGN's mains replacement proposal would significantly improve safety of the Network, is materially preferable to the AER's alternative and delivers an outcome that achieves the NGO.

AGN's Revised AA Proposal highlights that, consistent with the original proposal, it is necessary for AGN to replace Cast Iron (CI) and Unprotected Steel (UPS) mains and HDPE mains to ensure the ongoing safety of the Network. The Revised AA Proposal provides for the replacement of 1,265 kilometres of at risk mains during the next AA period, consistent with the volumes and deliverability outlined in our Initial AA Proposal. However, our updated analysis has led AGN to modify the composition of the proposed mains replacement program to reflect the results of modelling undertaken as part of our ongoing operations and in response to the AER Draft Decision.

A summary of each of these elements is provided below, with further detail provided in Attachment 8.10.

AGN's Regulatory and Legislative Obligations

The key legislative framework governing AGN's obligation to undertake mains replacement activities consists of the National Gas Objective (NGO), the revenue and pricing principles (RPP) under the National Gas Law (NGL), relevant criteria set out in the NGR, AGN's South Australian Gas Distribution Licence, the risk assessment framework set out in Australian Standard/New Zealand Standard (AS/NZS) 4645 Gas Distribution Network Management (which is given statutory force by section 55 of the *Gas Act 1997* and the *Gas Regulations 2012 (SA))* and the *Work Health and Safety Act 2012.*

More specifically, Section 23 of the NGL outlines the NGO:

> *"The objective of this [National Gas] Law 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."*

The focus of Section 23 is on the long-term interests of consumers with respect to price, quality, safety, reliability and security of supply. While price comes first in the list, there is nothing to suggest it is more important than any other factors. The mains replacement program focusses on ensuring the safe, reliable and secure supply of natural gas. It aims to replace mains which are at risk of fracturing or cracking in the interests of ensuring the safe operation of the distribution network. The mains replacement program is directly relevant to promotion of the NGO, as a distribution network with mains at risk of fracture cannot operate in a way which ensures a safe and reliable supply.

[10] Calculated by simply substituting AGN's proposed mains replacement capex for the AER Draft Decision mains replacement capex in the AER Post Tax Revenue Model.

Additionally, the NGL provides that the AER must, in performing or exercising an AER economic regulatory function or power, do so in a manner that will or is likely to contribute to the achievement of the NGO (Section 28(1)) and also take into account the RPP when exercising a discretion in approving or making those parts of an access arrangement relating to a reference tariff (Section 28(2)). In the current context, the most relevant revenue and pricing principle is Section 24(2) of the NGL, which provides:

> *"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."*

A "*regulatory* obligation or requirement" is defined in Section 6 of the NGL and includes a "*pipeline safety duty*", which is defined as a duty or requirement relating to the safe supply of natural gas or the safe operation of a pipeline.

To this extent, there are several concurrent "*pipeline safety duties"* requiring AGN to implement the mains replacement program. They are:

- Clause 8 of AGN's distribution licence, which is issued under the *Gas Act 1997* which clause requires that AGN implement the mains replacement program in the form approved by the Essential Services Commission of South Australia in November 2015;

- Clause 5 of AGN's South Australian Gas Distribution Licence which relates to safe operation of the network;

- Section 55 of the *Gas Act 1997* and regulation 37 of the *Gas Regulations 2012* which requires gas infrastructure to be operated safely and requires compliance with AS/NZS 4645, AS/NZS 1596 and AS 2885; and

- the *Work Health and Safety Act 2012* which requires AGN to ensure so far as is reasonably practicable that the health of workers, and any other person who may be affected by AGN's business undertaking, is not put at risk.

The revised mains replacement program also complies with the regulatory framework outlined in the NGR, which requires AGN to ensure forecasts are arrived at on a reasonable basis (Rule 74) and ensure that capex is prudent and efficient (Rule 79). More specifically:

- AGN's revised mains replacement program is based on the best estimate possible in the circumstances (satisfying Rule 74) because the volume of mains identified for replacement is informed by a rigorous risk assessment, which prioritises mains by location, crack rates and potential events, and because unit rates are based on competitive tender processes for the particular work required, and adopt AGN's historical rates where appropriate; and

- the capex proposed for mains replacement over the period conforms under Rule 79 of the NGR because it is necessary to maintain and improve the safety and integrity of services (NGR 79(2)(c)(i) and NGR 79(2)(c)(ii)), and AGN's South Australian Gas Distribution Licence requires it to reduce risk to as low as reasonably practicable (NGR 79(2)(iii)).

Risk Assessment

AGN's risk management framework is based on AS/NZS ISO 31000 Risk Management – Principles and Guidelines, and the requirements of AS 2885 Pipelines-Gas and Liquid Petroleum and AS/NZS 4645 Gas Distribution Network Management. Under this framework, AGN conducts a risk assessment of hazards associated with the mains in the distribution network in accordance with AS/NZS 4645. For each hazard, we consider the consequence and likelihood of that hazard occurring.

As noted by the AER in its Draft Decision, "*…the level of risk can vary across the different pipe types depending on several factors such as pressure of the pipes, and location of the pipes*". [11] Additionally, the pipe material can impact the risk assessment. To ensure proper consideration of the variables that affect the risk associated with mains, we have grouped the Network mains into 11 categories based on asset material, location and pressure. This allows for a more rigorous assessment of risk, particularly the likelihood of harm occurring than assessing mains in a single asset class. The mains categories considered in the mains replacement program risk assessment are as follows:

1. CI/UPS Central Business District (CBD) mains – all CI/UPS mains located within the Adelaide CBD;
2. CI/UPS trunk mains – medium pressure larger diameter CI/UPS trunk mains located along major carriageways and in older suburbs that contain older-style residential buildings with underfloor spaces, where escaped gas has the potential to collect;
3. CI/UPS higher risk areas – all low pressure CI/UPS mains in areas with a history of crack failure,[12] these mains are typically located in older suburbs that contain older-style residential buildings with underfloor spaces, where any escaped gas has the potential to collect;
4. CI/UPS remaining – the remaining CI/UPS mains in areas where there have been no recorded cracks to date;
5. HDPE 250 higher risk areas – Class 250 polyethylene (PE) mains, which operate at medium pressure and are located in areas with a history of crack failure;[13] These mains were installed during the 1970s and 80s and have become brittle and susceptible to cracking, and many are located in populated areas near buildings where escaped gas has the potential to collect;
6. HDPE 250 remaining – the remaining Class 250 PE mains, which operate at medium pressure, have become brittle and susceptible to cracking and are located in areas where there have been no recorded cracks to date; these mains may have sustained squeeze off damage, and as a result, are considered likely to exhibit slow crack growth failures in the future.
7. HDPE 575 (high risk areas) – Class 575 PE mains that operate at high or medium pressure and are located in areas with a history of cracking; many of these mains are located in populated areas near buildings where escaped gas has the potential to collect;
8. HDPE 575 remaining – the remaining Class 575 PE mains that operate at high or medium pressure, and are located in areas where there have been no recorded cracks to date; these mains may have sustained squeeze off damage, and as a result, are considered likely to exhibit slow crack growth failures in the future;
9. Multi-user inlet service (CI/UPS) – 1,328 predominantly UPS services running through unit developments and commercial premises across the network;
10. New PE – new PE pipe that has recently been installed in the network and is not considered susceptible to cracking; and
11. Protected steel – steel pipe with a PE coating that is typically now used only in high pressure applications and cathodically protected to maintain integrity and longevity; these mains are not considered susceptible to the type of cracking and integrity issues that affect other pipe materials.

Consistent with AS/NZS 4645, for each of the 11 mains categories defined above, AGN considered the severity of the consequence of an event and the frequency of this event occurring, having consideration for

[11] AER 2015, "*Confidential Appendix A – Attachment 6: Capital expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016–21*", November 2015, pg. 6A-14 and 6A-15.

[12] These mains have a crack frequency rate almost 2.5 times that of CI mains in the United Kingdom (UK).

[13] These mains have a crack frequency rate almost three times higher than CI/UPS mains.

the network characteristics, historical performance and international experience. For the purposes of this assessment, the event was defined as being:

> *'the consequences of a crack or leak in the gas mains that results in gas collecting in a building and causing explosion, and the frequency of this event resulting in fatalities or several people with life-threatening injuries.*

The AS/NZS 4645 framework considers the consequences of a mains failure event on 'People', 'Supply' and the 'Environment'. The framework ranks the severity of the failure event from 'Catastrophic' (multiple fatalities) to 'Trivial' (minimal impact on health and safety).

Figure 1.2 presents AGN's assessment of risk severity against the three categories set out in AS/NZS 4645. The key drivers of risk severity are the location of the pipe (proximity to population centres and buildings where escaped gas has the potential to collect and result in an explosion) and the pressure of the gas in the pipe. Though the AS/NSZ 4645 risk matrix considers impact on people, supply and the environment, standard risk management practice is to assess the likelihood of the highest consequence risk occurring when rating the risk event, which, as illustrated in Figure 1.2 is the risk to People.

FIGURE 1.2: SEVERITY OF HAZARD EVENT UNDER AS/NZS 4645 GUIDELINES FOR ASSET CLASSES 1 THROUGH 11 (NO MITIGATION MEASURES)

	Catastrophic	Major	Severe	Minor	Trivial
People	Multiple fatalities result 1 2	Few fatalities or several people with life-threatening injuries 3 4 5 6 7 8 9 10 11	Injury or illness requiring hospital treatment	Injuries requiring first aid treatment	Minimal impact on health and safety
Supply	Long term interruption of the supply	Prolonged interruption or long-term restriction of supply	Short term interruption or prolonged restriction of supply 2	Short term interruption or restriction of supply but shortfall met from other sources 1 3 4 5 6 7 8 9 10 11	No impact; no restriction of gas distribution network supply
Environment	Effects widespread, viability of ecosystems or species affected, permanent major changes	Major off-site impact or long-term severe effects or rectification difficult	Localised (<1ha) and short-term (<2 yr) effects, easily rectified	Effect very localised (<0.1 ha) and very short term (weeks), minimal rectification	No effect, or minor on-site effects rectified rapidly with negligible residual effect 1 2 3 4 5 6 7 8 9 10 11

Note: Definitions of asset classes 1 through 11 are provided on page 9 of this Attachment.

AS/NZS 4645 has five frequency classes, ranging from 'Frequent' (expected to occur once per year or more) down to 'Hypothetical' (theoretically possible but has never occurred on a similar gas distribution network).

The key drivers of risk likelihood are the pipe material and condition (propensity to crack) and the mains pressure. When assessing frequency, it is also important to consider proximity of the mains to the general population and/or buildings, and the historical occurrence of incidents that either resulted in or had the potential to result in a catastrophic or major event Figure 1.3 shows AGN's assessment of the risk frequency associated with gas mains.

FIGURE 1.3: FREQUENCY OF HAZARD EVENT UNDER AS/NZS 4645 GUIDELINES FOR ASSET CLASSES 1 THROUGH 11 (NO MITIGATION MEASURES)

Frequency Class	Frequency Description	AGN Asset Classification
Frequent	Expected to occur once per year or more	
Occasional	May occur occasionally in the life of the gas distribution network	1 2 3 5 7
Unlikely	Unlikely to occur within the life of the gas distribution network, but possible	4 6 8 9
Remote	Not anticipated for this gas distribution network at this location	
Hypothetical	Theoretically possible but has never occurred on a similar gas distribution network	10 11

Note: Definitions of asset classes 1 through 11 are provided on page 9 of this Attachment.

Combining the above severity and frequency analysis, the AS/NZS 4645 framework provides an overall risk rating for each category of main in the Network, assuming no mitigation measures are in place. As illustrated in Figure 1.4, of the 11 categories of mains identified by AGN, two are classed as 'Catastrophic', seven as 'Major' and two as 'Hypothetical'.

FIGURE 1.4: INHERENT MAINS RISK RATING UNDER AS/NZS 4645 GUIDELINES FOR ASSET CLASSES 1 THROUGH 11 (NO MITIGATION MEASURES)

	Catastrophic	Major	Severe	Minor	Trivial
Frequent					
Occasional	1 2	3 5 7			
Unlikely		4 6 8 9			
Remote					
Hypothetical		10 11			

Extreme High Intermediate Low Negligible

Note: Definitions of asset classes 1 through 11 are provided on page 9 of this Attachment.

AS/NZS 4645 provides direction on how the risks in a gas distribution network should be treated, and places an obligation on network operators to take action. Figure 1.5 shows the relevant risk treatments required by AGN's obligation under AS/NZS 4645 and the categories of main that require each treatment.

FIGURE 1.5: INHERENT RISK RANK AND RISK TREATMENT ACTIONS UNDER AS/NZS 4645 GUIDELINES

Risk Rank	Required Action	AGN Asset Classification
Extreme	Modify the threat, the frequency or the consequences to ensure that the risk rank is reduced to Intermediate or lower. For a gas distribution network in operation the risk must be reduced immediately.	1 2
High	Modify the threat, the frequency or the consequences to ensure that the risk rank is reduced to Intermediate or lower. For a gas distribution network in operation the risk must be reduced as soon as possible, typically within a timescale of not more than a few weeks.	3 4 5 6 7 8 9
Intermediate	Repeat threat identification and risk evaluation process to verify and, where possible, quantify the risk estimation; determine the accuracy and uncertainty of the estimation. Where the risk rank is confirmed to be Intermediate, if possible modify the threat, the frequency or the consequence to reduce the risk rank to Low or Negligible. Where the risk rank cannot be reduced to Low or Negligible action shall be taken to: a) remove threats, reduce frequencies and/or reduce severity of consequences to the extent practicable; and b) demonstrate as low as reasonably practicable (ALARP). For a gas distribution network that is in operation, the reduction to Low or Negligible or demonstration of ALARP must be complete as soon as possible, typically within a timescale of not more than a few months.	
Low	Determine the management plan for the threat to prevent occurrence and to monitor changes which could affect the classification.	10 11
Negligible	Review at the next review interval.	

Note: Definitions of asset classes 1 through 11 are provided on page 9 of this Attachment.

Consistent with Figure 1.5, the application of AS/NZS 4645 has identified 2,619 kilometres of at risk mains (that is mains with an inherent risk ranking of Extreme or High) which require AGN to take action as soon as practicable. This conclusion is further supported by industry experts Jacobs who were engaged by AGN to provide an independent and expert review of our mains replacement proposal. Specifically, Jacobs note that whilst they consider the severity ratings applied by AGN (Figure 1.2) to be conservative (i.e. potentially understates risk), they are supportive of our approach to mains replacement:

> *"The risk ratings that result from the application of the severity class and the frequency class are in our opinion overly conservative. We say they are conservative because of the concern expressed above that some pipes within the "CI & UPS higher risk" family, and HDPE higher risk families can reasonably be seen from the discussion above as falling within the "catastrophic" class."* [14]
>
> …
>
> *"It is our opinion that AGN's recognition of the need for the MRP [mains replacement program] and its proposed timing is consistent with a service provider acting "in accordance with accepted good industry practice" based on our direct experience with similar overseas programs (UK and US [United States]) for accelerated main replacement for Cast Iron, UPS and vintage plastic."* [15]
>
> …

14 Jacobs 2016, "*Mains Replacement Program Review*", January 2015, pg. 28. Provided as Attachment 8.11 to this Revised AAI.

15 Ibid, pg. 3.

> *"Even though the required action in the extreme class is stated to be immediate reduction in risk, we believe that a planned removal program within the shortest feasible time is entirely consistent with the requirement."*[16]

The Jacobs report is provided as Attachment 8.11 to this Revised AA Proposal.

AGN's approach to remediating risk is discussed in the following section.

Risk Mitigation

When assessing the most appropriate response to remediating risk, AGN considers the financial impact against the inherent risk, the level of risk reduction and the residual risk, to determine a prudent and efficient course of action. Where risk mitigation activities alone cannot reduce the risk to low or as low as reasonably practicable (ALARP), we seek to replace the mains so that low risk or ALARP can be achieved as quickly as possible. This has led AGN to develop the following risk mitigation strategies:

- increase frequency of leak surveys in areas identified as higher risk (proximity of mains to buildings, type of premises and ground conditions);
- pressure reduction in areas with a history of crack failure;
- increase the level of gas odorisation;
- replacement of all CI/UPS mains in the CBD and medium pressure trunk mains, with completion in the next AA period;
- replace as much of the 'High' risk CI/UPS, HDPE 250 and HDPE 575 mains as possible within delivery capability during the next AA period;
- replace all remaining 'High' risk CI/UPS, HDPE 250, and HDPE 575 mains as soon as reasonably practicable;
- replace all CI/UPS multi-user inlet services during the next AA period;
- research and utilise inline camera technology to identify defects and effect temporary repair in HDPE pipe that has not been prioritised for replacement during the next AA period (see Business Case SA52, Section 1.3.6.3);
- continue installation of ground vents over HDPE mains in locations where ground conditions could seal in gas leaks, making them difficult to detect (Business Case SA56); and
- develop a reliability forecast model for predicting the remaining life of HDPE 575, so that risk mitigation strategies (including replacement) can be optimised (Business Case SA54).

We have already implemented the first three strategies listed above and have commenced replacing the highest risk mains in the current AA period. The remaining strategies form the basis of our proposal for the next AA period.

Under our Gas Distribution Licence AGN is required to use its *best endeavours* to *conduct operations so as to prevent death or injury to, persons or damage to property.*[17] Best endeavours means *to act in good faith and use all reasonable efforts, skill and resources.*[18] Therefore, in order to demonstrate the inherent network

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16 Jacobs 2015, "*Mains Replacement Program Review*", December 2015, pg. 28. Provided as Attachment 8.11 to this Revised AAI.

17 AGN Gas Distribution Licence, Section 5.1(a).

18 AGN Gas Distribution Licence, Schedule 1 – Definitions.

risk during the next AA period is being reduced to as low as reasonably practicable, AGN must replace the volume of mains during the next AA period that skill and resources will allow.

Based on performance over the past three years, we have developed the capacity to efficiently replace around 250 kilometres of mains per year, or 1,245 kilometres of planned replacement during the next AA period, with the potential to deliver an additional 20 kilometres of reactive (piecemeal) works. This rate is below what would be required to replace all 2,619 kilometres of mains rated ‘Extreme’ or ‘High’ (Figure 1.5) within the next AA period.

As detailed in Attachment 8.10, replacing 2,619 kilometres is unachievable over the next AA period as AGN would need to double its delivery capability to more than 500 kilometres per year. Such deliverability would require the sourcing, training and inducting additional contractors, co-ordinating an increased level of access to mains replacement areas and likely paying a cost premium to attract the required resources to South Australia.

As a result, AGN proposes to maintain the current deliverability of circa 250 kilometres of mains replacement per annum over the next AA period.

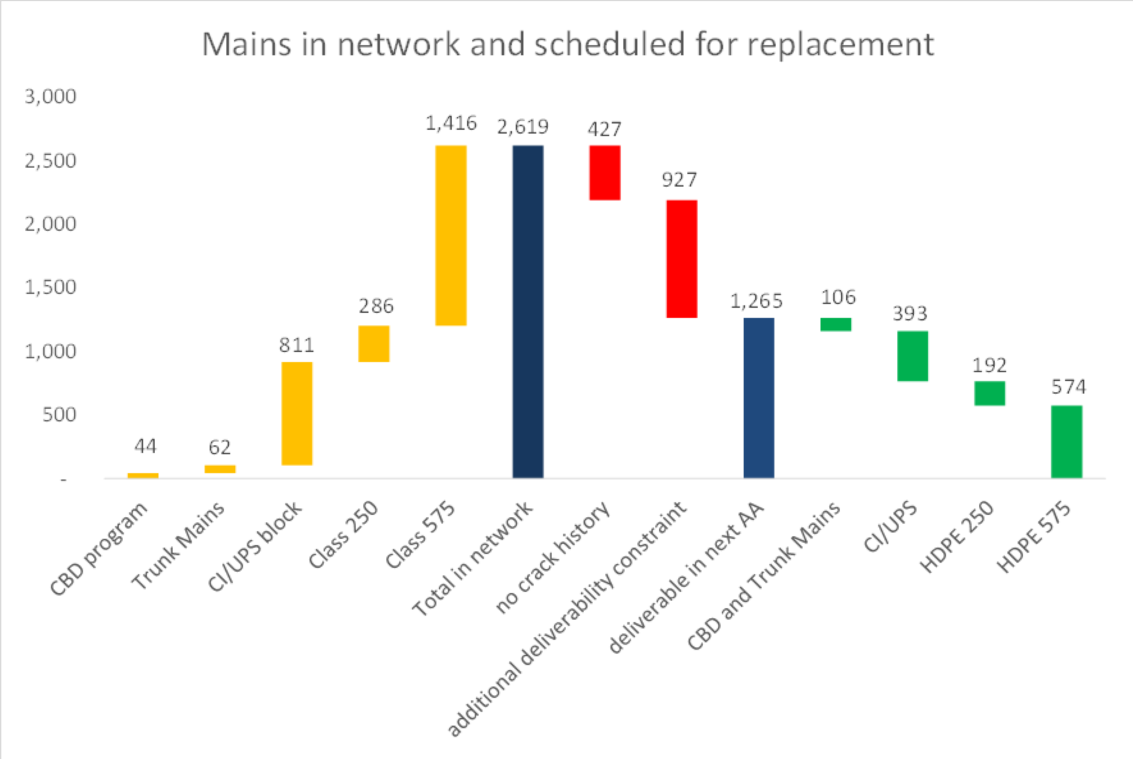
Given our delivery capability will not result in the replacement of all high risk mains over the five-year period, we have undertaken a risk prioritisation process to rank the risk of particular mains.

As illustrated earlier in Figure 1.5, AGN’s risk assessment has identified two asset categories as having an “Extreme” risk rating – these are the CI/UPS CBD program (44 kilometres) and the CI/UPS trunk mains (62 kilometres). AGN’s proposal prioritises the replacement of these mains over the next AA period.

AGN has implemented a risk prioritisation model to identify which of the remaining high risk mains should be replaced during the next AA period and which can be prudently deferred to subsequent years. The model implemented by AGN is based on the principles used in the UK for replacement prioritisation of CI mains. As detailed in Attachment 8.10, this model provides a risk priority ranking of assets by suburb based on the historical frequency of cracks and a relationship between the frequency of cracks, gas in building explosions and fatalities.

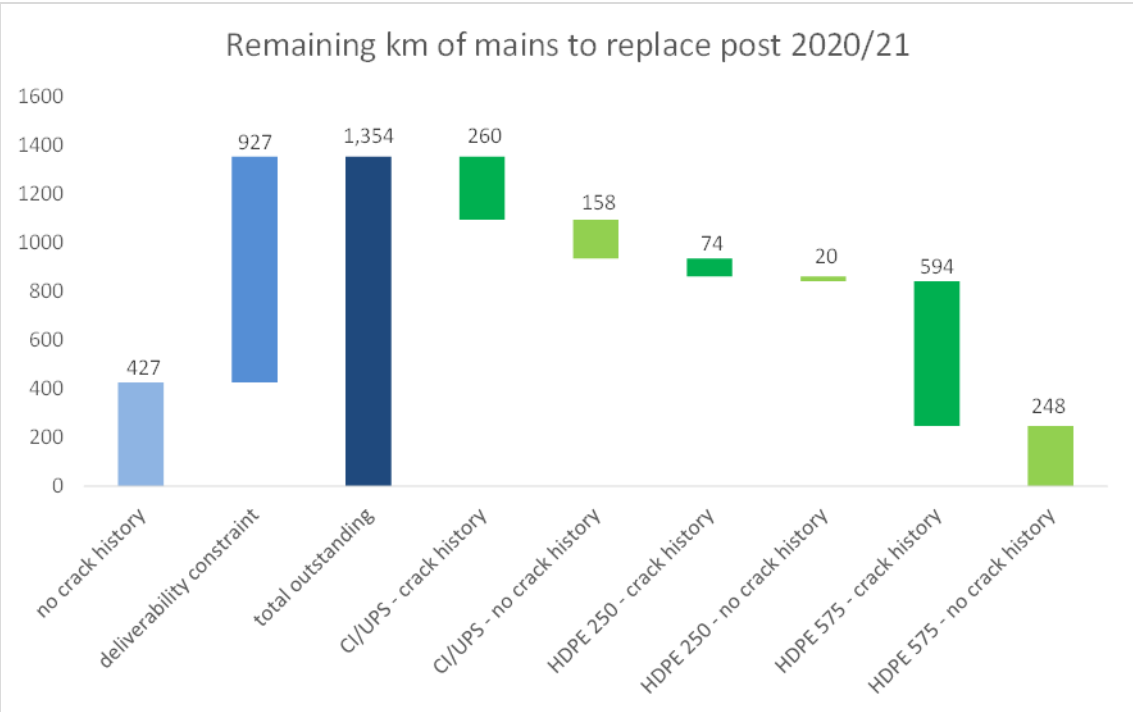
Figure 1.6 shows the progression of how the efficient delivery and prioritisation of our proposed mains replacement program was derived, whilst Figure 1.7 presents the make-up of mains that will need to be prioritised for future AA period.

FIGURE 1.6: CALCULATION OF MAINS IN NETWORK AND DELIVERY VOUMES FOR THE NEXT AA PERIOD



It is noteworthy that the outstanding 1,354 kilometres of 'High' risk mains (Figure 1.7) will be carefully monitored during the next AA period, with risk mitigation activities (such as reducing pressure) being a temporary solution until these mains can be replaced in subsequent years. The 1,354 kilometres of mains will also be subject to further analysis and prioritisation to ensure the highest risk mains are replaced first. This means mains in suburbs with a crack history are likely to be replaced earlier in the subsequent AA period than those with no crack history.

FIGURE 1.7: MAINS TO BE PRIOTISED AND REPLACED IN FUTURE AA PERIODS



This approach gives rise to the following mains replacement program which is reflected in this Revised AA Proposal.

TABLE 1.3: REVISED MAINS REPLACEMENT PROGRAM (KILOMETRES)

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
CI/UPS	109	103	101	99	89	499
HDPE	153	153	153	153	153	766
Total	262	256	254	251	242	1,265

Note: Totals may not sum due to rounding.

AGN acknowledges that whilst the total volume of mains to be replaced over the next AA period is consistent with that originally proposed in July 2015 (1,265 kilometres compared to 1,273 kilometres) the composition between CI/UPS and HDPE has changed. More specifically in July 2015 AGN proposed to replace 862 kilometres of CI/UPS and 411 kilometres of HDPE, compared to 499 kilometres of CI/UPS and 766 kilometres of HDPE in this Revised AA Proposal.

Despite this change in composition, AGN's strategy and position with respect to mains replacement has not changed since our Initial AA Proposal. AGN remains firmly of the opinion that the CI/UPS mains in the Network and the HDPE 575 and 250 mains need to be replaced. This position is supported not only by our own risk assessment (as illustrated earlier in this Chapter) but also by industry experts Jacobs (see Attachment 8.11).

What has changed in our revised proposal is the prioritisation of replacement. This change is reflective of further analysis being undertaken by AGN, consistent with our ongoing management and operation of the Network and in response to the AER's Draft Decision.

In practice, AGN will continue to refine its prioritisation model throughout the next AA period, updating for new information as it becomes available and reprioritising as appropriate.

Cost Impact Analysis

The AS/NZS 4645 risk assessment and AGN's risk prioritisation model provide a qualitative and quantitative assessment of the inherent risk in the network. However, consistent with the AER's Draft Decision, AGN also recognises the importance of understanding the costs associated with addressing this risk, the most efficient delivery profile, and the price impact to customers.

To this end we have conducted an indicative cost impact analysis, which considers several scenarios for addressing the network risk. This analysis identifies the net present cost (NPC) to customers of each mains replacement scenario, the residual network risk and the average cost per customer per year compared to the AER's alternative proposal.

The purpose of the cost impact analysis is to help AGN assess whether the mains replacement program is proportionate to the level of risk involved, and to evaluate the potential impact of changes to the composition and rate of replacement on customers. Implicit in this however, it is noteworthy that safety considerations remain the primary driver, with financial considerations the secondary driver, in developing a mains replacement program.

The cost impact analysis undertaken by AGN considered four scenarios:

1. Scenario A AGN Revised Proposal – Replacing 1,265 kilometres of the highest risk mains during the next AA period and replacing the outstanding 'High' risk mains during the subsequent AA period. All 1,328 multi-user service inlets will also be replaced in the next AA period. This scenario limits the replacement of 'High' risk rated mains to AGN's delivery capability.
2. Scenario B Five Year Program – Replacing all 2,619 kilometres of at risk mains during the next AA period (a five-year program). All 1,328 multi-user service inlets will also be replaced in the next AA

period. This scenario replaces all 'High' risk mains over the next AA period and assumes no delivery constraints or premium unit rates associated with securing sufficient resources.

3. Scenario C Piecemeal Replacement – Replacing all 2,619 kilometres of at risk mains during the next 20 years in a piecemeal fashion. This scenario incorporates a higher unit rate for replacement as a result of the less efficiently bundled replacement program.

4. Scenario D AER Draft Decision Aligned – Replacing as many kilometres as possible within the expenditure provided for in the AER's Draft Decision. Given the adjustment to unit rates and matching the kilometres to the risk prioritisation model, this allows for replacement of 561 kilometres of the highest risk mains during the next AA period, with the balance (2,058 kilometres) to be replaced over the following four AA periods. No multi-user service inlets will be replaced during the next AA period.

The results of this analysis are summarised in Table 1.4 which shows that:

- Scenarios A and B are the only approaches which reduce the residual network risk to "Low" by 2021;
- Though Scenario B (a five-year replacement program) reduces the inherent network risk more quickly than AGN's proposal, it is not currently achievable given deliverability constraints;
- Scenario 4, the AER Draft Decision, would result i.n an additional $3.45 net present cost saving to each customer per year over the useful life of the assets, but does not reduce the inherent risk of the network to a level which is acceptable under AS/NZS 4645 and the conditions of AGN's Gas Distribution Licence.

TABLE 1.4: MAINS REPLACEMENT COST IMPACT ANALYSIS

	Opex ($M)	Capex ($M)	Total Expenditure ($M)	Net Present Cost per Customer per Year	Residual Risk in 2021	Additional Price Reduction per Customer per Annum
Scenario A: AGN Revised AA Proposal	13.9	599.3	613.2	$18.65	Low	Base
Scenario B: Five Year Program	6.6	599.3	605.9	$20.36	Low	$1.71 increase
Scenario C: Piecemeal Program	34.2	972.7	1,007	$24.52	High	$5.86 increase
Scenario D: AER Draft Decision Aligned	35.9	599.3	635.2	$15.20	High	$3.45 decrease

Having consideration for the above analysis, AGN considers that Scenario A, the AGN revised proposal, allows AGN to reduce the risk of the Network to ALARP and meet the conditions of its Gas Distribution Licence whilst still representing efficient and prudent costs to customers.

Summary of AGN's Revised Mains Replacement Proposal

AGN submits that the AS/NZS 4645 risk assessment demonstrates that the risk associated with failure of CI/UPS and HDPE mains needs to be addressed. The most effective method of eliminating this risk is to replace all these mains with new PE.

Having regard to the above, AGN considers a program that only provides for replacement of 577 kilometres out of 2,619 kilometres of extreme and high risk mains (as per the AER's Draft Decision) would not reduce the risk in the network to ALARP, as is required under AS/NZS 4645 and AGN's South Australian Gas Distribution Licence. We therefore conclude the AER's alternative proposal does not represent a mains replacement program that would be undertaken by "*a prudent service provider, acting efficiently, in* *accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services"*[19], and is therefore not consistent with the NGR or materially preferable.

AGN maintains that the inherent network risk and associated delivery costs justify that it is prudent and efficient to replace 1,265 kilometres of at risk mains during the next AA period. Consistent with AGN's Initial AA Proposal, this includes replacing all CI/UPS mains in the Adelaide CBD and other higher risk areas. However, rather than replace all residual CI/UPS mains in the network, priority will be given to replacing HDPE mains, particularly those located in higher risk locations, as informed by our risk prioritisation model.

We consider this modified program reduces the inherent network risk to 'Low' and where this is not possible, ALARP, and is consistent with the actions of a prudent and efficient service provider, acting in accordance with good industry practice to maintain and improve the safety of gas distribution services. Replacing these assets satisfies the criteria under Section 79(2)(c) of the NGR, which states capital expenditure is justifiable if:

> *"(c) the capital expenditure is necessary:*
>
> *(i) to maintain and improve the safety of services; or*
>
> *(ii) to maintain the integrity of services; …"*

The slight change in volumes to be replaced in next AA period, the change in composition of replacement and the update to unit rates (see Section 1.3.7) gives rise to total capex over the next AA period of $326 million, 12% lower than our Initial AA Proposal.

1.3.2 Augmentation

The AER included $4 million of augmentation capex in the Draft Decision, which is 77% lower than the $18 million proposed by AGN. As outlined in Table 1.5, AGN does not accept the AER's decision in relation to SA21 or SA71. Further detail on AGN's response on these matters is provided in Section 1.3.2.1 and 1.3.2.2 and in Attachment 7.1A.

TABLE 1.5: SUMMARY OF AGN'S RESPONSE TO THE AER DRAFT DECISION ON AUGMENTATION CAPEX

Initiative	AER Draft Decision	AGN Response	AGN Comment
SA14; SA15; SA17; SA19	Accept AGN Proposal	Accept Draft Decision	No comment.
Pitting Issues (SA21)	Reject AGN Proposal	Respond to Draft Decision	AGN does not agree that it is prudent to defer this expenditure to the subsequent (2021/22 to 2025/26) AA period given the level of corrosion on the M21 and M53 TP pipeline.
Pitting Issues (SA21a)	Accept as Opex	Accept Draft Decision	No comment.
Murray Bridge (SA71)	Reject AGN Proposal	Respond to Draft Decision	SA71 is required to facilitate organic growth in demand in the region and is the least cost option when compared with deferring installation and increasing the Murray Bridge TP pipeline's pressure.

The resultant revised proposal provides for augmentation capex of $15 million which is 18% less than our Initial AA Proposal.

19 National Gas Rules 79(1)(a).

1.3.2.1 Southern Transmission Pipeline / Pitting Issues under HSS and Replacement M21 & M53 Pipelines (SA21)

AGN's original SA21 Business Case included a capex allowance of $7 million to replace two pipelines (TP Pipelines M21 and M53) that have significant pitting corrosion and are nearing the end of their useful lives and to also replace a section of the M53 Pipeline at Christies Creek.

In its Draft Decision, the AER did not make any provision for the proposed pipeline replacement on the basis of advice it received from its engineering consultant, Sleeman Consulting (Sleeman). Sleeman claimed that the current level of corrosion was less than what would be required to necessitate expedited capital works and that AGN should carry out further analysis on the level of corrosion. Furthermore, Sleeman suggested AGN should implement a monitoring regime as part of Business Case SA21a to determine when replacement is justified.[20]

AGN has provided the additional analysis suggested by Sleeman. As outlined in the Addendum to Business Case SA21 (provided in Attachment 7.1A), this analysis demonstrates that the M21 and M53 pipelines are nearing the end of their useful life and, having regard to the cost of other options, such as deferring the replacement until the subsequent AA period and increasing monitoring in the next AA period, replacement during the next AA period is consistent with the actions of a prudent and efficient network operator.

Consistent with the above, AGN has resubmitted SA21 with the same capex forecast as originally proposed. This equates to capex of $7 million during the next AA period.

1.3.2.2 Murray Bridge Augmentation (SA71)

AGN's original SA71 proposal included a capex allowance of $3 million to upgrade the capacity of supply to the Murray Bridge township through the installation of a 2 kilometre steel main.

In its Draft Decision, the AER did not make any provision for the proposed pipeline upgrade on the basis of advice it received from Sleeman that the number of new connections assumed by AGN were not reasonable and that any demand growth in the region could be managed through increasing the pressure of the existing pipeline.

AGN has sought to provide greater clarity about the driver of this augmentation initiative. As outlined in the Addendum to Business Case SA71 (provided in Attachment 7.1A), this augmentation is required to meet existing demand and organic growth in the region, as opposed to the new step out developments that Sleeman expressed some concerns about. Additionally, increasing pipeline pressure is not a practical solution as discussed in the Business Case, and would only act to delay the augmentation until later in the next AA period and is not the most prudent and efficient option.

As a result, AGN remains of the opinion that increasing the capacity of the pipeline servicing the Murray Bridge township is required over the next AA period. Furthermore, Regional Development Australia (Murraylands and Riverland) supports this project and is concerned that deferral of the project, *"… will impede our region's economic growth and ability to continue to attract new businesses to the region*."[21]

Consistent with this, AGN has resubmitted SA71 on the same basis as originally proposed. This equates to capex of $3 million during the next AA period.

1.3.3 Regulators and Valves

The AER included $11 million of regulators and valves capex in the Draft Decision, which is 19% lower than the $14 million proposed by AGN. As outlined in Table 1.6, AGN does not accept the AER's decision in relation to the reclassification of SA09 to opex. Further detail relating to AGN's position is provided in Section 1.3.3.1.

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[20] Sleeman 2015, "*Review of Capex Forecasts for Selected Projects*", 18 November 2015, pg. 5 to 6.

[21] Regional Development Australia (Murraylands and Riverland), "*Gas Supply Upgrades – Murray Bridge*", December 2015.

TABLE 1.6: SUMMARY OF AGN'S RESPONSE TO THE AER DRAFT DECISION ON REGULATORS AND VALVES CAPEX

Initiative	AER Draft Decision	AGN Response	AGN Comment
SA08; SA22; SA33; SA34; SA45; SA70	Accept AGN Proposal	Accept Draft Decision	No comment.
Valve Corrosion Protection (SA09)	Accept as Opex	Respond to Draft Decision	AGN has received expert advice that this expenditure should be classified as capex as per our initial proposal (see 1.3.3.1).
Vulnerable Meters (SA75)	Reject AGN Proposal	Accept Draft Decision	Although SA75 received some support from stakeholders during the engagement program, AGN accepts the AER's position that this is a site specific cost.

The resultant revised proposal provides for regulators and valves capex of $11 million, which is 2% higher than the Draft Decision and 17% less than our Initial AA Proposal.

1.3.3.1 Valve Corrosion Protection (SA09)

The AER's Draft Decision accepts that valve corrosion protection work is required, but suggests that it is an opex item, as opposed to capex as proposed by AGN. Furthermore, the AER notes that it is a continuation of current work that was previously accepted as opex.

> *"… we consider the proposed project, 'Valve corrosion protection' (SA09), is an opex item."*[22]

And

> *"…This is a continuation of a program that AGN proposed in the current access arrangement period, which we accepted. In our draft and final decision for the previous access arrangement review, we included this project in our alternative opex estimate. AGN, then Envestra, agreed with this classification in its revised proposal. The CCP [Consumer Challenge Panel] also asked whether this project is a maintenance activity (opex). We therefore consider we should assess this project as opex."*[23]

As acknowledged by the AER, this project is a continuation of work being undertaken by AGN in the current AA period. Expenditure relating to this work in the current AA period has been classed as capex, which classification has been reflected and accepted by the AER in other parts of this submission – for example our Regulatory Asset Base. Implicit in this, the work does not form part of AGN's base year opex, and as such, the AER's reclassification provides no funding to complete future work.

The classification of this work program as capex is consistent with independent expert advice from Deloitte who state that:

> *"On balance, we consider the expenditure in relation to SA09 to be Capex in nature…"*[24]

Consistent with the above, AGN resubmits SA09 ($0.3 million) as capex.

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22 AER 2015, *"Attachment 6 – Capital Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21"*, November 2015, pg. 6-45.

23 Ibid, pg. 6-47 and 6-48.

24 Deloitte 2016, "*Advice regarding Opex versus Capex classification for project SA09 Valve Corrosion Protection*", January 2016. Provided as Attachment 7.10 to this Revised AAI.

1.3.4 Information Technology

The AER included $38 million of IT capex in the Draft Decision, which is 37% lower than the $60 million proposed by AGN. As outlined in Table 1.7, AGN does not accept the AER's decision in relation to SA59 and SA60. Further detail relating to AGN's position is provided in the remainder of this Section.

TABLE 1.7: SUMMARY OF AGN'S RESPONSE TO THE AER DRAFT DECISION ON IT CAPEX

Initiative	AER Draft Decision	AGN Response	AGN Comment
SA57; SA58; SA62; SA82; SA84	Accept AGN Proposal	Accept Draft Decision	No comment.
Mobility (SA59)	Reject AGN Proposal	Respond to Draft Decision	AGN does not accept the decision for these initiatives. Further information has been provided to demonstrate that such programs are consistent with good industry practice and are common for other distributors. Furthermore both initiatives have a positive economic value and are necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations. These projects are also required for AGN to achieve the implied productivity gains set out in Attachment 7.8 of this Revised AA Proposal.
Business Intelligence (SA60)	Reject AGN Proposal	Respond to Draft Decision	
SA64; SA65	Reject AGN Proposal	Accept Draft Decision	No comment.

The resultant Revised AA Proposal provides for IT capex of $55 million, which is 46% higher than the Draft Decision and 7% less than our Initial AA Proposal.

1.3.4.1 Overview of AGN's IT Proposal and Cost Performance

As detailed in our AA Proposal, AGN is required to handle substantial amounts of information on a daily basis, including information relating to customer connections and disconnections, laying and repairing mains, managing gas repairs as well as meter reading and billing information. This volume of activity requires ongoing investment in systems that link together to allow the high volumes of data to flow from one system to the other and ensure full functionality to manage critical business processes and satisfy retail market rules.

In the current AA period, AGN initiated a national program of work to replace old state-based IT systems that have been in place for over 10 years, and as such, are no longer supported by the appropriate vendor or able to be updated to prevent system security vulnerabilities. Considerable progress has been made towards the nationalisation of the IT systems and infrastructure over the current AA period.

AGN considers that the IT projects re-proposed in this Revised AA Proposal are those that are effectively completing the significant investments already made in the nationalisation of IT systems in the current AA period. To this extent, the additional investment is required to fully access the benefits and functionality of previous programs.

Furthermore, AGN considers the proposed IT spend to be relatively modest and consistent with good industry practice when compared to other utilities (including competitors such as electricity distributors) in Australia, which is demonstrated in a cost benchmarking study conducted by KPMG and provided as Attachment 8.12 to this Revised AA Proposal.

More specifically, in order to assess AGN's comparative IT expenditure, KPMG was engaged to conduct cost benchmarking relating to AGN's historic and forecast IT expenditure compared to a sample of up to 24 gas and electricity distributors in Australia between 2006/07 and 2020/21. KPMG considered a range of metrics. The KPMG benchmarking showed that AGN has historically sat below the industry mean across every performance indicator, suggesting that AGN has historically underinvested in IT compared to other businesses. Table 1.8 provides more specific findings from KPMG in relation to capex.

TABLE 1.8: SUMMARY OF KPMG'S FINDINGS ON CAPEX

Metric	KPMG's Conclusion
Capex per customer	*"AGN SA [South Australia] has been consistently below the industry mean in the previous and current AAPs [Access Arrangement Periods], which suggest under-investments in capex, when compared to the industry during these periods."*[25]
IT capex as a percentage of capex	*"AGN SA's IT capital investments in the previous AAP and in the early years of the current AAP have been below the industry mean. The two peak IT periods (2014 to 2015 and forecasted from 2017 to 2019) are consistent with AGN SA's planned IT capex investment strategy, following the under-investment in the previous AAP. Overall, the results indicate AGN SA's IT capex level has been below industry and will trend in line with industry, following the IT capex investment peaks."*[26]
IT capex per customer	*"AGN SA has been the lowest and below the industry mean, prior to the IT capex forecast peak in 2018 and 2019. The planned IT capex over the next AAP will enable AGN SA to catch-up to industry IT expenditure level. The results suggest AGN SA's capex are, in general, comparably below the industry."*[27]

Based on their analysis, KPMG made the following observation:

> *"The IT investment cycles are evident over the three AAPs, that are the subject of this benchmarking report. In the previous AAP, from 2006/07 to 2010/11, AGN SA has made very low levels of IT capex investments. This was followed by an increase in the current AAP to deliver a number of IT programs in bringing its technology capabilities in line with industry. The investment peaks reflect a catch-up period following an under-investment in the previous AAP."*[28]

It is noteworthy that given the timing of the response to the Draft Decision, KPMG conducted their review using forecast IT spend based on AGN's Initial AA Proposal as submitted to the AER on 1 July 2015. That is, with the full IT proposal provided to the AER on 1 July 2015 (7% more than that being proposed by AGN in this Revised AA Proposal). KPMG's conclusion is that this step-up in spend is required in order to facilitate AGN's 'catch up' to the industry, which is demonstrated in Figure 1.8 below. AGN's Revised AA Proposal has been moderated since the submission of the Initial AA Proposal.

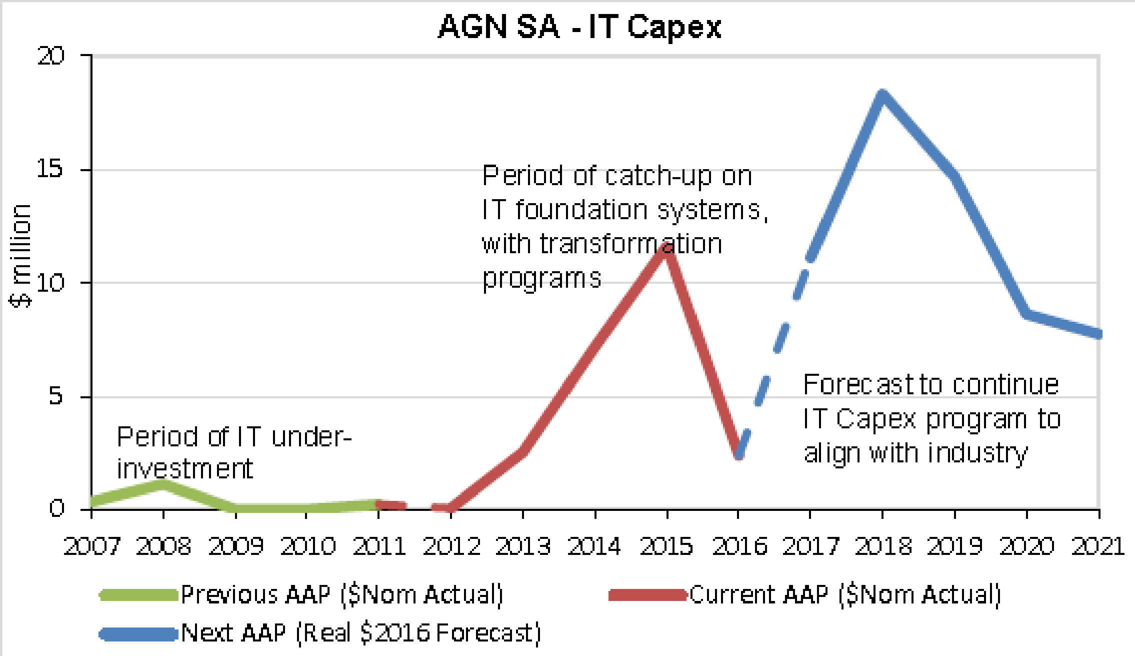
25 KPMG 2015, "*SA Australian Gas Networks Limited: Information Technology Cost Benchmarking*", December 2015, pg. 12. Provided as Attachment 8.12.

26 Ibid, pg. 15.

27 Ibid, pg. 16.

28 Ibid, pg. 8.

FIGURE 1.8: AGN'S IT CAPEX PROFILE



Source: KPMG, "SA Australian Gas Networks Limited: Information Technology Cost Benchmarking", 2015.

In summary, in order to fully access benefits of current systems, derive productivity gains, deliver improved customer service and to maintain good industry practice, consistent with industry peers and competitors, AGN must invest in IT. This follows a sustained period whereby AGN's IT investment has been below the industry mean, and in the case of IT capex per customer, at times the lowest of the circa 20 businesses included in the KPMG sample.

To this extent AGN is re-proposing the Mobility Integration and Business Intelligence Business Cases that were not accepted by the AER in its Draft Decision. The remainder of this section details our response to the AER in relation to these two projects.

1.3.4.2 Mobility Integration (SA59)

AGN's original SA59 Business Case included a capex allowance of $9 million and an opex allowance of $0.3 million to integrate field mobility solutions into the Enterprise IT systems in order to reduce response times, improve customer service delivery and decision making, improve the safety and integrity of services, to ensure AGN's compliance with regulatory obligations and facilitate efficiency improvements (including through avoided future cost increases).

The AER rejected the proposed expenditure on the basis that it was:

> *"…not satisfied that the proposed capex for this project is necessary to maintain and improve safety of services, to maintain the integrity of services or to comply with regulatory obligations."*[29]

Furthermore, the AER noted that the project was discretionary as "*there are no significant problems with the current system to justify a step change in costs*".[30]

[29] AER 2015, "*Attachment 6 – Capital Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 6-43.

[30] Ibid.

In response to the AER's Draft Decision, AGN has sought to further document the costs, inefficiencies and risks associated with the existing manual, paper-based processes and the effect they are having on AGN's ability to improve service delivery to customers, the safety and integrity of services and compliance with regulatory obligations. Additionally, AGN has demonstrated that the benefits arising from eliminating these inefficient processes outweigh the proposed project costs, delivering a positive NPV over a 10-year period.

It is also noteworthy that AGN understands that the AER has previously approved expenditure on similar mobility related projects for many of our gas and electricity distribution counterparts including SA Power Networks (SAPN), Ergon Energy, Energex, AusNet Services (gas), Multinet, United Energy and Jemena (gas and electricity).[31] This initiative provides AGN with the opportunity to catch-up to industry peers following a period of underinvestment and, in doing so, achieve benefits for customers.

Consistent with the above, AGN has resubmitted SA59 with the same capex forecast as originally proposed. This revision equates to capex of $9 million during the next AA period. As outlined in Attachment 7.1A and Attachment 7.8, AGN is not re-proposing the $0.3 million of related opex on the basis that more recent analysis has shown that the demonstrated project benefits outweigh the forecast increase in opex over the next AA period.

1.3.4.3 Business Intelligence (SA60)

AGN's original SA60 Business Case included a capex allowance of $9 million to improve AGN's data analysis and reporting capabilities and, in so doing, improve decision making throughout the business and minimise the risk of non-compliance with relevant regulations and legislation. The project is also expected to result in the implementation of more efficient end-to-end business processes and improvements in customer service, the safety and integrity of services and compliance with regulatory obligations.

The AER rejected the proposed expenditure on the basis that it was:

> *"…discretionary in nature because while it does provide improvements in data analysis and usage, AGN has not identified deficiencies in these areas that require addressing."*[32]

Furthermore, the AER noted that the original Business Case did not demonstrate that the project would yield a positive net economic value.

In response to the AER's Draft Decision, AGN has sought to further document the inefficiencies and risks associated with the existing data analytics, reporting and decision-making systems and the effect they are having on AGN's ability to make timely and efficient decisions about assets and achieve risk reductions in other areas, as well as improving service delivery to customers, the safety and integrity of services and complying with regulatory obligations.

Despite the difficulty with quantifying the decision-making related benefits associated with this project, AGN has been able to demonstrate that the project does result in a positive NPV over 10 years (for further justification, please refer to Attachment 7.1A). Importantly, the Business Intelligence project is forecast to generate benefits over the next AA period, which will be used to offset certain opex costs and to achieve the implied efficiencies set out in this Revised AA Proposal (Attachment 7.8).

For example, it is envisaged that the Business Intelligence project will increase the capability of AGN to develop the type of HDPE risk model described in opex Business Case SA54, which will ultimately be a key input into the integrity management of HDPE (including optimising maintenance and future replacement

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31 SAPN, *"IT Field Force Mobility Business Case",* 3 July 2015, Ergon Energy, *"Forecast Expenditure Summary Information, Communication and Technology, 2015 to 2020",* pg. 4, Energex, *"ICT Services Expenditure, 2015-20 regulatory proposal",* October 2014, pg. 5, AusNet Services, *"Electricity Distribution Price Review 2011-2015 Regulatory Proposal",* November 2009, pg. 158, Multinet, *"Gas Access Arrangement Review January 2013-December 2017 AAI",* 30 March 2012, pg. 85, Jemena Gas Networks, *"2015-20 AAI, Appendix 6.3 IT Strategy and Asset Management Plan",* June 2014, pg. 9, Jemena Electricity Networks, "*2016-20 Electricity Distribution Price Review Regulatory Proposal",* Attachment 7-3, 30 April 2015, pg. 87 and United Energy, *"Capital Expenditure Overview – ICT, 30 April 2014",* pg. 11.

32 AER 2015, "*Attachment 6 – Capital Expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-21*", November 2015, pg. 6-43.

strategies). As such, AGN has not sought additional expenditure for this Business Case in its Revised Proposal on the basis that the Business intelligence project is approved.

This is just one example of the anticipated future benefits of the Business Intelligence tool to be realised over subsequent years, which explains why other distributors are investing in this area and why the AER has previously approved these such initiatives (including most recently, Jemena Gas Networks and Energex).

Consistent with the above, AGN has resubmitted SA60 on the same capex basis as originally proposed. This revision equates to capex of $9 million during the next AA period.

1.3.4.4 Summary

As demonstrated in the above sections, the IT projects approved by the AER or re-proposed by AGN will enable AGN to correct for historic underinvestment in IT and to 'catch up' to accepted good industry practice. Additionally, both the Mobility Integration and Business Intelligence projects have been demonstrated as NPV positive with ongoing future benefits, including through improved customer services, for both AGN and consumers of natural gas.

In particular (as detailed in AGN's response to the AER's Draft Decision on opex (Attachment 7.8)), AGN has forecast future productivity improvements amounting to around $22 million and will also absorb numerous opex step change costs amounting to a further $9 million. AGN considers it is these types of projects (namely, the Business Intelligence project) that will provide AGN with the capacity to absorb these future costs and to deliver the overall expenditure program as set out in this Revised AA Proposal.

1.3.5 Growth Assets

The AER included $85 million of growth capex in the Draft Decision, which is 6% lower than the $91 million proposed by AGN. As outlined in Table 1.9, AGN does not accept the AER's decision in relation to SA24. Furthermore, following the rejection of AGN's proposed Significant Extension Event Pass Through[33], AGN has prepared an additional Business Case (SA25) relating to the extension of the network to Mount Barker. Further detail relating to AGN's position is provided in Section 1.3.5.1 and 1.3.5.2.

TABLE 1.9: SUMMARY OF AGN'S RESPONSE TO THE AER DRAFT DECISION ON GROWTH CAPEX

Initiative	AER Draft Decision	AGN Response	AGN Comment
General Growth Assets	Accept AGN proposal	Accept Draft Decision	No comment.
Two Wells (SA24)	Reject AGN proposal	Respond to Draft Decision	AGN has ensured the assumptions relating to this initiative are consistent with the AER's Draft Decision. This analysis shows the project is NPV positive, and as such, AGN resubmits this Business Case.
Mount Barker (SA25)	Not applicable	Not applicable	Following the rejection of the Significant Extension Event Cost Pass Through, AGN submits a Business Case relating to a network expansion to Mount Barker.

The resultant Revised AA Proposal provides for growth capex of $114 million, which is 33% higher than the Draft Decision and 25% higher than our Initial AA Proposal.

33 AER 2015, "*Attachment 11: Reference Tariff Variation Mechanism | Draft Decision: Australian Gas Networks Access Arrangement 2016-2021*", November 2015, pg. 11-36 and 11-37.

1.3.5.1 Two Wells (SA24)

AGN's original SA24 Business Case included a capex allowance of $5 million to extend the high pressure network by 9 kilometres to the Two Wells township north of Adelaide. In its Draft Decision, the AER decided not to make any provision for the Two Wells project because it stated that it was not satisfied that the proposed expenditure was justified under Rule 79(2)(b). More specifically, the AER noted that when adjustments were made to assumptions made by AGN (to correct for perceived inconsistencies in demand and revenue assumptions), the NPV analysis for this extension was negative over a 20-year period.[34]

As outlined in the Addendum to Business Case SA24 (provided in Attachment 7.1A), consistent with feedback in the AER's Draft Decision, AGN has revisited the following assumptions:

- demand per connection assumptions have been revised to be consistent with the AER's Draft Decision on demand;
- tariff assumptions have been revised to be consistent with the AER's Draft Decision on tariffs (noting that this Revised AA Proposal sets tariffs higher than the Draft Decision); and
- the discount rate used in the cost benefit analysis is consistent with the AER's Draft Decision.

AGN has also provided additional evidence as to the basis of the penetration rate assumptions and duration over which the economic analysis has been undertaken.

The resulting analysis indicates this expenditure is NPV positive and is consistent with Rule 79 of the NGR.

Consistent with the above, AGN has resubmitted SA24 on the same capex basis as originally proposed. This revision equates to capex of $5 million over the next AA period.[35]

1.3.5.2 Mount Barker (SA25)

AGN's Initial AA Proposal for the next AA period noted that, whilst investigations into the feasibility of reticulating gas in the Mount Barker region had commenced, the investigations were not sufficiently progressed to submit a capex proposal by 1 July 2015. AGN therefore proposed to manage the extension through a 'Significant Extension' cost pass-through event, which would be triggered if AGN's Board approved the decision to reticulate gas to the area and the extension was deemed to satisfy the relevant requirements of the NGR. [36]

This proposal for the 'Significant Extension' Cost Pass Through was not accepted by the AER in its Draft Decision because, in its view, the "*limited assessment of an application under the cost pass through mechanism should not be considered an alternative avenue for approval of expenditure*".[37]

In the six months since submitting the Initial AA Proposal, AGN has done further work to assess the technical and financial feasibility of the Mount Barker extension. This work has found that the present value of the expected incremental revenue to be generated from the Mount Barker extension exceeds the present value of the capex, and as such, is justifiable under Rule 79(2)(b) of the NGR.

Consistent with this analysis, AGN plans to invest $24 million of capex to extend and reticulate the Mount Barker region. Such investment is expected to result in the connection of around 7,000 new customers over a 20-year period, which will lower the cost of delivering pipeline services over the life of the project to all

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[34] AER 2015, "*Attachment 6: Capital expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-2021*", November 2015, pg. 6-24.

[35] For clarification, customer connections attributable to the network expansion projects in Two Wells are assumed to be incorporated into the customer connection forecasts approved by the AER in the Draft Decision.

[36] AGN 2015, "*SA Access Arrangement Information*", July 2015, pg. 266-267.

[37] AER 2015, "*Attachment 11: Reference Tariff Variation Mechanism | Draft Decision: Australian Gas Networks Access Arrangement 2016-2021*", November 2015, pg. 11-36.

existing customers because it will enable the largely fixed costs of operating the gas Network to be spread over a larger customer base.

AGN therefore proposes that the capex for supplying natural gas to Mount Barker is approved by the AER under Rule 79.

It is noteworthy that the Government of South Australia has formally advised the AER of its support for the extension of the network to Mount Barker:

> *"The Government of South Australia has considered this proposal [AGN's Initial AAI Proposal] and considers that there are many benefits of extending the gas network into Mount Barker. Access to natural gas will allow Mount Barker residents to take advantage of an alternative low emission energy source for various applications including cooking, water heating and space and central heating. Natural gas can also be used for a wide range of commercial and industrial applications. Provision of natural gas in Mount Barker will offer residents and businesses greater choice and improve energy security.*
>
> *…*
>
> *It is for these reasons that I would like to formally advise the Australian Energy Regulator that the Government of South Australia supports AGN's proposal to extend its distribution network to Mount Barker at a cost of no more than $3 per customer."*[38]

1.3.6 Other Distribution System

The AER included $10 million of other distribution system capex in the Draft Decision, which is 73% lower than the $37 million proposed by AGN. As outlined in Table 1.10, AGN does not accept the AER's decision in relation to SA52 or the modifications made to SA10 and SA31. Further detail relating to AGN's position is provided in Section 1.3.6.1 through 1.3.6.3.

TABLE 1.10: SUMMARY OF AGN'S RESPONSE TO THE AER DRAFT DECISION ON OTHER DISTRIBUTION SYSTEM CAPEX

Initiative	AER Draft Decision	AGN Response	AGN Comment
SA06; SA36; SA37; SA49; SA53	Accept AGN proposal	Accept Draft Decision	No comment.
Sleeve Railway Crossing (SA10)	Modify AGN proposal	Respond to Draft Decision	AGN does not accept the assumed inspection rate proposed by the AER.
Inlets Inside Cavities (SA28)	Modify AGN proposal	Accept Draft Decision	Whilst AGN is confident that the volumes originally proposed in SA28 can be achieved, we have accepted the AER's Draft Decision to reduce the annual volume from 3,000 to 2,000 per annum.
Fire Safety Valves (SA31)	Modify AGN proposal	Respond to Draft Decision	AGN does not accept the AER's modification of installation rates in High Bushfire Risk Areas (HBRAs) nor the rejection of installations to brush fence sites. Although AGN does not agree with the rejection of the installation of fire safety valves at new and existing domestic premises, we accept the Draft Decision on this matter.
Inlets Under Buildings (SA32)	Accepted as opex	Accept Draft Decision	No comment.

[38] Government of South Australia 2015, "*Additional submission on Australian Gas Networks proposed Access Arrangement for 2016-2021*", November 2015. Available to download from the AER's website: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/australian-gas-networks-sa-%E2%80%94-access-arrangement-2016%E2%80%9321/draft-decision"

HDPE Cameras (SA52)	Reject AGN proposal	Respond to Draft Decision	AGN does not accept the AER's decision in relation to this initiative. The HDPE Camera inspection work is an important part of our wider mains replacement program and integral to reducing risk to as low as reasonably practicable and increasing safety in the next AA period.

The resultant Revised AA Proposal provides for Other Distribution System capex of $21 million, which is 113% higher than the Draft Decision and 42% lower than our Initial AA Proposal.

1.3.6.1 Sleeve Railway Crossings (SA10)

AGN's original SA10 Business Case included a capex allowance of $2 million to inspect and repair 55 (11 per annum) transmission pressure sleeved railway crossings within the Network.

In its Draft Decision, the AER accepted the basis for the inspection and remediation work and the unit costs, but reduced the level of proposed expenditure to $1 million on the basis of advice it received from its engineering consultant, Sleeman. Sleeman's advice related to the number of inspections AGN proposed to carry out in the next AA period:

> *"I consider completion of the inspection programme to be prudent to ensure safe and reliable operation of the transmission pressure pipeline system into the long-term. However, I note that the inspection programme to date has not identified any major corrosion problems. While it may be possible to carry out 11 sleeved railway crossing inspections per year, results to date confirm the inspection programme can be safely and prudently completed at a slower rate, and therefore at lower present value cost to consumers."*[39]

Sleeman went on to recommend that the number of inspections to be carried out in the next year be reduced to the average number that AGN has achieved in the current AA period, which Sleeman estimated to be five per annum.

AGN accepts the AER's position that the proposed number of inspections to occur during the next AA period should be based on historic levels, but does not agree with the average rate estimated by Sleeman because it understates the actual rate AGN has achieved in the current AA period.

In the current AA period, AGN has inspected and remediated 25 sites over a three-year period (2012/13 to 2014/15), which is equivalent to an average rate of 8.3 sites per annum.[40] This is higher than the five per annum estimated by Sleeman. Consistent with this, AGN has resubmitted SA10 with revised volumes and costs. This revision equates to capex of $2 million during the next AA period ($0.6 million) more than the AER's Draft Decision and $0.6 million less than our Initial AA Proposal).[41]

1.3.6.2 Fire Safety Valves (SA31)

AGN's original SA31 proposal included a capex allowance of $10 million to maintain and improve the safety of services and maintain the integrity of services by installing fire safety valves (FSVs) in High Bush Fire Risk Areas (HBRAs), certain brush fence sites, new domestic sites and existing sites where the meter is due to be changed. This proposal was driven by safety considerations and informed by stakeholder

[39] Sleeman 2015, "*Review of Capex Forecasts for Selected Projects*", 18 November 2015, pg. 11.

[40] Note, due to extraordinary circumstances, this program of work was not extended across the full five-year current AA period. Despite this, AGN achieved only one less inspection than proposed in the current AA period. Further information is provided in Attachment 7.1A.

[41] Note: Revised capex for this work is $1.6 million (rounded to $2 million) compared to the capex outline in our Original AA Proposal of $2.2 million (rounding to $2 million).

engagement, during which participants indicated they would be willing to pay for the installation program described above.[42]

In its Draft Decision, the AER accepted the proposed installation of FSVs in HBRAs and the associated cost of installation, but reduced the rate of replacement and rejected any installation in non-HBRAs. This Draft Decision was based on advice from the AER's engineering consultant Sleeman. More specifically Sleeman:[43]

- recommended that the number of installations in HBRAs in the next AA period be reduced from the 9,900 proposed by AGN to 5,000, on the basis this was a "*realistic, achievable and manageable programme*" which he claimed reflected the rate most recently achieved by AGN; and
- suggested that installation of FSV in non-HBRAs was not justifiable because the risk was low.

AGN accepts the AER's position that the proposed number of installations in HBRAs to occur during the next AA period should be based on historical levels, but does not agree with the average rate Sleeman has estimated because it understates the actual rate achieved by AGN in the current AA period. More specifically, the installation of FSVs in HBRAs commenced in 2013/14 and in the last two years 3,747 FSVs have been installed. This equates to an average installation rate of approximately 1,900 per annum, which is higher than Sleeman's estimate of 1,000 per annum.

Furthermore, AGN has demonstrated that an even higher rate of 2,294 installations per annum is achievable as per the actual installation rate achieved in 2013/14. Importantly, as noted in our Addendum to Business Case SA31 (Attachment 7.1A), this higher rate is in the best interests of customers as a result of the associated safety benefits and will result in FSVs being installed in all HBRAs by the end of the next AA period.

In relation to brush fence sites, AGN does not agree with Sleeman's assertion that the risk associated with brush fence fires is "*very low*".[44] Rather, AGN believes that this work program is necessary to improve the safety of services and maintain the integrity of services and is therefore justified under Rule 79(2)(c)(i) and (ii) of the NGR.

Consistent with this, AGN proposes to install 160 FSVs per annum at these sites, bringing the total number of annual FSV installations over the next AA period to 2,185, a rate that is slightly above the average achieved in the current AA period (1,900) but below the rate achieved in 2013/14 (2,294).

AGN's original Business Case SA31 reflected stakeholder engagement with respect to the roll-out of FSVs to new and replacement meters. Whilst we maintain that the installation of FSVs to these meters is consistent with the values of our consumers and would improve network safety, AGN accepts the AER's decision to reject this element of SA31.

Consistent with the above, AGN has resubmitted SA31 with updates to the proposed number and timing of installations. This revision equates to capex of $1 million during the next AA period, $0.7 million more than the AER's Draft Decision and $9 million less than our Initial AA proposal.

1.3.6.3 HDPE Camera Investigation and Repairs (SA52)

AGN's Initial AA Proposal included an allowance of $12 million to carry out an internal inspection and repair program on High Pressure Class 575 HDPE distribution mains. This project has been developed in response to a number of incidents that have occurred in the South Australian network over the last seven years as a result of brittle crack failures of HDPE mains and was a component of AGN's wider risk mitigation strategy.

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[42] AGN 2015, "*Access Arrangement Information for Australian Gas Networks' South Australian Natural Gas Distribution Network*", 1 July 2015, pg. 62.

[43] Sleeman 2015, "*Review of Capex Forecasts for Selected Projects*", 18 November 2015, pg. 9-10.

[44] Ibid.

In its Draft Decision, the AER noted that while it accepted that the use of an in-line HDPE camera could "*assist in deferring mains replacement at a relatively low cost*" it could not be satisfied that the proposed expenditure was conforming capex without a Business Case or CBA. [45] Through further discussions with the AER, it was noted that while the AER had access to the original Business Case for the HDPE camera investigation and repair work, it was looking for a detailed quantitative assessment of the costs and benefits (including the reduction in risk) associated with the options that AGN considered when developing the Business Case.

AGN does not accept the AER's Draft Decision in relation to SA52 as this project is an important complement to the mains replacement program, detailed in this Revised AA Proposal. As outlined earlier in Section 1.3.1, it is not practicable to replace all at risk mains over the next AA period, and as a result, this project forms an integral part of a broader package of work that is designed to reduce the risk associated with AGN's HDPE network to ALARP, consistent with Australian Standard AS/NZS 4645 and AGN's obligations in relation to the mains that will not be replaced during the next AA period.

In response to the AER's Draft Decision, AGN has taken the opportunity not only to provide additional information in relation to the proposed mains replacement program (of which SA52 is a component), but also to update SA52 for the following factors:

- reflect information received following submission of our Initial AA Proposal in July 2015:
    - since submitting the original Business Case, AGN has completed in-line camera inspections on 2.5 kilometres of a 9 kilometre pilot precinct, the results of these inspections were detailed in our response to the AER's Information Request 023 and found the following in relation to the assumptions used to determine the cost build-up of the original Business Case:
        - more squeeze-off locations per kilometre were identified than expected;
        - the distance that the camera cable can extend is less than expected;
        - the length of main that can be inspected per day is lower than expected; and
        - wear and tear of the camera cable is higher than expected;
    - as a result of these findings, the cost breakdown per excavation site has increased, which is reflected in the addendum provided in Attachment 7.1A to this Revised AA Proposal;
- update for revised mains replacement volumes (as per Section 1.3.1):
    - AGN is proposing to replace a higher volume of Class 575 HDPE mains than originally forecast in our Initial AA Proposal, as a result, lower volumes of mains will require inspection over the next AA period.

In summary, AGN has revised the cost build-up of this Business Case to reflect the most up-to-date information available and has amended the volumes to reflect the updated mains replacement program. Further detail is provided in the Addendum to Business Case SA52, submitted as part of Attachment 7.1A. This revision equates to capex of $10 million during the next AA period, which is $2 million less than our Initial AA Proposal.

[45] AER 2015, "*Attachment 6: Capital expenditure | Draft decision: Australian Gas Networks Access Arrangement 2016-2021*", November 2015, pg. 6-38.

1.3.7 Mains Replacement Unit Rates

In its Draft Decision, the AER raised several concerns relating to the unit rates used in AGN's proposed mains replacement program. Primary concerns (identified in the AER's Confidential Appendix A) are that some unit rates:

- were based on tender submissions from potential contractors rather than awarded contracts;
- included a premium for night time work and other costs associated with work to be carried out in higher congestion zones, that were not adequately supported; and
- appeared inconsistent with historical rates experienced, so a revealed unit rate was a better estimate.

The AER did not directly use these unit rates to develop its alternative forecast for the mains replacement program, instead calculating a capex reduction proportionate to its recommend reduction in mains replacement volumes. However, the AER did invite AGN to provide further information to support the unit rates in its Revised AA Proposal.

Our Revised AA Proposal (as outlined in Attachment 8.10) puts forward the most appropriate unit rates having regard to the scope, location and volume of work. Newly available information, such as tenders received post our July 2015 submission have also been reflected.

These rates reflect either historical actuals experienced, historical actuals experienced adjusted for new location specific premiums or market tested tendered rates that are in the process of being awarded. As required by NGR 74, these forecast unit rates have been *arrived at on a reasonable basis* and *represent the best estimate possible in the circumstances*.

A summary of our approach for each of the mains replacement unit rates follows:

- CI/UPS General Block Replacement – AGN's initial proposal reflected the average tendered rate for this work plus an amount for material and other costs. The AER's Draft Decision was to accept the rate for materials and other costs, but to replace the average tendered rate with the actual revealed historical rate for similar work[46], on the basis that tenders were yet to be awarded and the AER was therefore unable to assess if these rates were efficient.

  AGN maintains that unit rates arrived at through a competitive tender process are efficient as the process is designed to reveal the most efficient rate available in the market to undertake the work. Furthermore, we consider using the average tendered rate[47] is a better estimate than the historical revealed rate as it is a reflection of current market conditions, is based on the identified scope of works, and specifically considers the location and volume of work to be completed over the next AA period.

  Consistent with this, AGN's resultant revised proposal is as per our Initial AA Proposal, which unit rates are 14% higher than the AER's Draft Decision.

- CI/UPS CBD Block Replacement and Trunk Replacement – AGN's initial proposal was a weighted average contractor rate in 2014/15, with loadings applied to some zones reflecting the different conditions that would be encountered (for example, traffic management and need for night works as the program moves towards the CBD area). The AER did not accept AGN's proposal that zones within the CBD required different work practices, rather they applied the CBD block unit rates realised in 2014/15 with additional funds for meter relocation.

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46 AGN was unable to reconcile the rates derived by the AER and is currently seeking further clarification.

47 There are five suppliers on AGN's national panel of approved mains replacement contractors that tender for works in South Australia. The average tendered rate relied upon from AGN for this work reflects input from three contractors that have been awarded work for 2016/17, it excludes rates from a fourth contractor because the price was more than 20% higher than others and from a fifth contractor who's rates were not available as due to only recently being added to the panel.

AGN accepts the AER's Draft Decision that the 2014/15 awarded unit rate can be applied to some zones within the CBD where the scope of works is substantially the same. However, AGN does not consider that this same rate can be applied throughout the entire CBD.

For example, AGN has been instructed by the Adelaide City Council to undertake night works within certain areas of the CBD to minimise disruption. Night works attract a premium cost consistent with the related Enterprise Bargaining Agreement, double handling of spoilage due to tips not being open at night, the slower rate at which work can be done, and the additional set-up works. AGN has not undertaken similar work in 2014/15 and so the historical rates are not reflective of these costs.

Consistent with this, AGN has accepted the AER's Draft Decision in relation to several zones within the CBD, but we maintain that a premium is required for the remaining zones to allow for different work conditions. AGN's resultant revised proposal is 30% and 88% higher than the AER's Draft Decision for Block Replacement and Trunk Replacement respectively.

- Services Replacement – AGN's initial proposal reflected the rates provided for services replacement as part of the block replacement tenders. The AER's Draft Decision was to consider the two lowest cost tender responses only.[48] Since our Initial AA Proposal, we have received additional tenders for this work, which tenders specifically identify the cost of service replacement alone (i.e. not part of the black replacement broader work program – consistent with the work to be undertaken over the next AA period). AGN's revised proposal reflects the weighted average of the lowest unit rates for each tenderer. The resultant revised proposal 2% higher than our Initial AA Proposal.

- HDPE Replacement (Class 250 and 575) – AGN's initial proposal reflected the actual historical cost incurred for similar work. AGN considers that this was the best information available at the time of our Initial AA Proposal due to the relatively new nature of this replacement. The AER's Draft Decision asked AGN to provide updated tender response or contract information as part of this Revised AA Proposal. Consistent with this, AGN's has updated its proposed rate to reflect recently received tendered contract rates. The resultant revised unit rate proposal is approximately 34% lower than our Initial AA Proposal.

- CI/UPS Medium Pressure Trunk Mains Replacement – AGN's initial proposal reflected the weighted average three-year historical rate for similar works. The AER's Draft Decision was to modify AGN's proposal to reflect the weighted average contractor rate for three suburbs only, in which no trunk mains replacement took place. AGN maintains that the weighted average three-year rate remains the best forecast or estimate possible under the circumstances. Consistent with this, AGN's resultant revised proposal is 66% higher than the AER's Draft Decision and consistent with our Initial AA Proposal.

These unit rates are reflected in our revised mains replacement costs as detailed in Section 1.3.1. Overall, the revised unit rates result in an $81 million decrease in the proposed capex for the mains replacement program, primarily driven by the reduction in rates for HDPE replacement to reflect tendered rates received post our Initial AA Proposal.[49]

It is noteworthy that AGN's revised unit rates are based on its proposed volume of activity across the AA period. Any material shift in volumes may impact unit rates. For example, a reduction in volume is likely to result in an increase in the unit rates due to a smaller scale or a decrease if the same contractors are competing for less work. Given the uncertainty regarding volume changes and the subsequent need for contractors to re-tender, AGN has not factored this impact in the expenditure forecast or cost benefit analysis.

1.3.8 Escalation

In order to account for future increases in labour and construction costs, AGN's Initial AA Proposal applied a forecast cost escalation rate that was calculated as an average of BIS Shrapnel and Deloitte Access Economics (DAE) forecasts of real labour and construction labour price changes. This escalation rate was

48 AGN was unable to reconcile the rates derived by the AER and is currently seeking further clarification.

49 In other words, if unit rates had not been updated from the Initial AA Proposal, total mains replacement capex (assuming the revised volumes defined earlier in this Attachment) would be approximately $81 million higher than we are submitting in this Revised AA Proposal.

used to forecast unit rates associated with capex initiatives. AGN proposed zero escalation on the cost of materials.

The AER accepted our proposed methodology and application of forecast escalation[50] to all categories with the exception of New Estate connections. In respect of New Estate connections, the AER revised AGN's capex forecast to reflect actual contract provisions, which provisions net-off the Consumer Price Index (CPI) from the previous year against CPI in the current year, and then multiply the result by a factor of 0.85. The AER applied this escalation rate to this capex category, through to the end of the next AA period.

However, the contracts expire either 31 December 2017, or 30 June 2018. AGN has therefore modified the AER's approach to reflect the expiry date of the contracts, and from 1 July 2018 has applied the same forecast escalation as has been applied for the other capex categories.

1.4 Summary

AGN in this Revised AA Proposal has provided the AER with the additional information requested in the Draft Decision. As outlined in this Attachment (and associated documents) this information illustrates that a capex allowance in excess of that provided by the AER in its Draft Decision, but below that originally proposed by AGN, is prudent and efficient and satisfies all relevant criteria under the NGR.

Further information on each of the Business Cases AGN is responding to is provided in specific Addendums (Attachment 7.1A) as part of our response to the AER's Draft Decision. These documents provide the additional information required by the AER in support of the revised capex forecast. The resultant capex forecast is provided in Table 1.11 (excluding cost escalation and overheads) and Table 1.12 (including cost escalation and overheads).

In summary, over the next AA period, AGN's Revised AA Proposal is 7% ($50 million) less than our Initial AA Proposal and 62% ($244 million) more than the AER's Draft Decision.

Further detail relating to our revised mains replacement program is provided in Attachment 8.10.

The capex forecast model, which shows the derivation of the capex forecasts, is provided as Attachment 8.7A to this Revised AA Proposal.

50 Note, the AER used the updated DAE forecast.

TABLE 1.11: COMPARISON OF AGN CAPEX PROPOSAL, AER DRAFT DECISION AND AGN REVISED PROPOSAL

$2014/15 million	AGN Initial AA Proposal	AER Draft Decision	AGN Revised AA Proposal	Variance ($m) (Revised AA Proposal less Draft Decision)	Variance (%) (Revised AA Proposal v Draft Decision)
Mains Replacement	369.9	167.7	326.0	158.3	94%
Meter Replacement	17.1	17.1	17.1	0.0	0%
Augmentation	17.9	4.1	14.6	10.5	256%
Telemetry	1.1	1.1	1.1	0.0	1%
Regulators	13.6	11.0	11.3	0.3	2%
Information Technology	59.7	37.9	55.4	17.5	46%
Growth Assets	90.6	85.4	113.8	28.4	33%
Other Distribution System	37.0	10.0	21.3	11.3	113%
Other Non-Distribution System	5.0	5.0	5.0	0.0	1%
Escalation	14.9	7.0	14.0	7.0	100%
Overheads	60.4	46.8	57.7	10.9	23%
Gross Total Capex	687.3	393	637.3	244.3	62%
Contributions	3.6	3.6	3.6	0.0	0%
Net Total Capex	683.7	389.4	633.7	244.3	63%

Note: Totals may not add due to rounding.

TABLE 1.12: BREAKDOWN OF REVISED CAPEX FORECAST (EXCLUDING COST ESCALATION AND OVERHEADS)

$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Mains Replacement	70.6	68.4	65.0	64.0	58.1	326.0
Meter Replacement	4.2	4.0	3.7	2.9	2.3	17.1
Augmentation	1.0	8.1	3.7	1.7	0.2	14.6
Telemetry	0.3	0.2	0.2	0.2	0.1	1.1
Regulators	2.2	2.2	2.4	2.4	2.2	11.3
Information Technology	9.1	17.1	14.0	8.0	7.1	55.4
Growth Assets	17.0	16.1	16.9	45.8	18.4	114.1
Other Distribution System	4.5	4.3	4.3	4.2	4.2	21.3
Other Non-Distribution System	1.3	1.0	0.9	0.9	0.9	5.0
Total Capex	110.1	121.5	110.9	129.9	93.4	565.9

Note: Totals may not add due to rounding.

TABLE 1.13: BREAKDOWN OF REVISED CAPEX FORECAST (INCLUDING COST ESCALATION AND OVERHEADS)

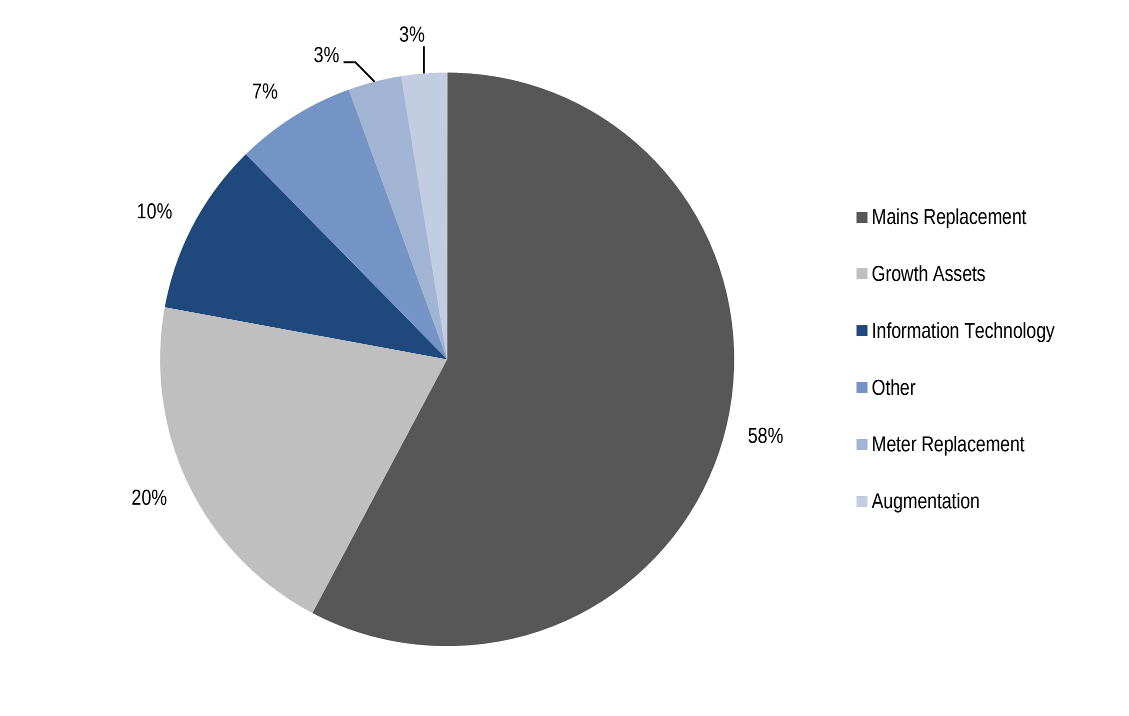
$2014/15 million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Mains Replacement	78.3	76.4	73.4	72.1	67.9	368.1
Meter Replacement	4.7	4.5	4.1	3.2	2.6	19.1
Augmentation	1.1	9.1	4.1	1.9	0.2	16.4
Telemetry	0.3	0.3	0.2	0.2	0.2	1.2
Regulators	2.4	2.4	2.6	2.6	2.5	12.6
Information Technology	10.1	19.1	15.8	9.0	8.2	62.1
Growth Assets	18.8	17.8	19.0	51.4	21.5	128.4
Other Distribution System	4.9	4.8	4.8	4.6	4.8	23.8
Other Non-Distribution System	1.5	1.2	1.0	1.0	1.0	5.6
Total Capex	122.0	135.4	125.1	146.0	108.8	637.3

Note: Totals may not add due to rounding.

TABLE 1.14: REVISED CAPEX FORECAST INCLUDING COST ESCALATION AND OVERHEADS (REAL AND NOMINAL)

$ million	2016/17	2017/18	2018/19	2019/20	2020/21	Total
$2014/15	122.0	135.4	125.1	146.0	108.8	637.3
$2015/16	123.6	137.2	126.8	148.0	110.2	645.8
Nominal	126.7	144.1	136.5	163.3	124.7	695.4

FIGURE 1.9: REVISED FORECAST CAPEX (INCLUDING COST ESCALATION AND OVERHEADS)



Note: Totals may not add due to rounding.