



FINAL DECISION

Australian Gas Networks

Access Arrangement

2016 to 2021

Attachment 6 – Capital expenditure

May 2016

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Note

This attachment forms part of the AER's final decision on the access arrangement for Australian Gas Networks South Australian distribution network for 2016–21. It should be read with all other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 - Services covered by the access arrangement

Attachment 2 - Capital base

Attachment 3 - Rate of return

Attachment 4 - Value of imputation credits

Attachment 5 - Regulatory depreciation

Attachment 6 - Capital expenditure

Attachment 7 - Operating expenditure

Attachment 8 - Corporate income tax

Attachment 9 - Efficiency carryover mechanism

Attachment 10 - Reference tariff setting

Attachment 11 - Reference tariff variation mechanism

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Shortened forms

Shortened form	Extended form
AA	Access Arrangement
AAI	Access Arrangement Information
AER	Australian Energy Regulator
AGN	Australian Gas Networks
ATO	Australian Tax Office
capex	capital expenditure
CAPM	capital asset pricing model
CCP	Consumer Challenge Panel
CESS	Capital Expenditure Sharing Scheme
CPI	consumer price index
CSIS	Customer Service Incentive Scheme
DRP	debt risk premium
EBSS	Efficiency Benefit Sharing Scheme
ECM	Efficiency Carryover Mechanism
ERP	equity risk premium
Expenditure Guideline	Expenditure Forecast Assessment Guideline
gamma	value of imputation credits
GSL	Guaranteed Service Level
MRP	market risk premium
NECF	National Energy Customer Framework
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NIS	Network Incentive Scheme
NPV	net present value
opex	operating expenditure
PFP	partial factor productivity
PPI	partial performance indicators
PTRM	post-tax revenue model

Shortened form	Extended form
RBA	Reserve Bank of Australia
RFM	roll forward model
RIN	regulatory information notice
RoLR	retailer of last resort
RPP	revenue and pricing principles
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	Service Target Performance Incentive Scheme
TAB	tax asset base
UAFG	unaccounted for gas
WACC	weighted average cost of capital
WPI	Wage Price Index

6 Capital expenditure

This attachment outlines our assessment of AGN's proposed conforming capital expenditure (capex) for 2010–16 and forecast capex for the 2016–21 access arrangement period. Expenditure referred to in this attachment is un-escalated unless otherwise stated.

6.1 Final decision

6.1.1 Conforming capital expenditure for 2010–16

We approve \$389.4 million (\$2014–15) of total net capex for AGN during the period 2010–2015 as conforming capex under rule 79 of the NGR. Table 6.1 shows our approved capex for 2010–15 by category.

Table 6.1 AER approved expenditure by category over 2010–16 (\$million, 2014–15)

Category	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16(a)
Connections (Market expansion)	22.4	19.8	19.4	25.5	23.4	18.8
Mains replacement	15.5	23.6	36.5	45.5	48.6	61.9
Meter replacement	2.7	2.2	2.4	3.6	3.9	3.6
Augmentation	1.3	6.2	15.2	5.1	2.1	15.1
Telemetry	0.2	0.2	0.2	0.3	0.2	0.5
Regulators	0.2	0.3	0.9	2.7	3.2	0.7
IT	0.3	0.1	2.4	6.8	10.5	2.2
Other distribution system	0.0	1.6	0.8	3.2	1.1	1.6
Other non–distribution system	0.8	0.0	0.7	0.6	0.8	2.3
Overheads	0.0	5.9	7.5	7.9	9.0	10.3
GROSS TOTAL CAPITAL EXPENDITURE	43.3	59.8	86.0	101.2	102.8	116.9
Contributions	0.3	0.3	1.7	0.6	0.9	0.2
NET TOTAL CAPITAL EXPENDITURE	43.0	59.5	84.3	100.6	102.0	116.7

Source: AER analysis; AGN, *Response to AER information request - AER AGN 041A* [email to AER], 29 February 2016.

Note: (a) As set out in attachment 2 and section 6.4.1 of this attachment, we have not assessed the 2015–16 amounts as approved capex under this decision. This is because these values are estimates. We will undertake the assessment of whether the 2015–16 amounts are conforming capex as part of the next access arrangement determination.

6.1.2 Conforming capital expenditure for the 2016–21 access arrangement period

We approve total net capex of \$550.5 million (\$2014–15) for 2016–21 as conforming capex under rule 79(1) of the NGR.

AGN proposed \$683.7 million in its initial proposal. We approved \$389.4 million in our draft decision.¹ The revised proposal AGN submitted in January sought \$633.7 million (\$2014–15) total net forecast capex for 2016–21. AGN subsequently provided an updated capex forecast, which reduced the mains replacement component of its capex forecast from \$326.0 million to \$277.2 million (discussed further below). This reduced its total capex forecast to \$581.4 million. Our final decision represents a reduction of 5.3 per cent to AGN's updated capex forecast of \$581.4 million (\$2014–15), or 13.1 per cent from its January revised proposal. It is \$161.1 million (\$2014–15)—or 41.4 per cent—higher than the total capex forecast approved in our draft decision.

The increase from our draft decision largely reflects our acceptance of AGN's modified mains replacement proposal of \$277.2 million.

Table 6.2 shows our approved capex for the 2016–21 access arrangement period for each year by category. We have revised the access arrangement having regard to our reasons for refusing to approve AGN's proposal and the further matters identified in the NGR section 64(2). Our revisions are reflected in the *Approved Access Arrangement, AGN's SA distribution networks 1 July 2016 – 30 June 2021* (May 2016).²

Table 6.2 AER approved capital expenditure by category over the 2016–21 access arrangement period (\$million, 2014–15)

Category	2016–17	2017–18	2018–19	2019–20	2020–21	Total
Mains replacement	61.1	50.4	56.8	57.7	51.2	277.2
Meter replacement	4.2	4.0	3.7	2.9	2.3	17.1
Augmentation	0.6	0.5	1.5	9.3	2.7	14.6
Telemetry	0.3	0.2	0.2	0.2	0.1	1.1
Regulators	2.1	2.1	2.3	2.3	2.1	11.0
IT	9.1	17.1	14.0	8.0	7.1	55.4
Growth assets	17.0	16.1	16.9	17.6	18.1	85.6
Other distribution system	4.5	4.3	4.3	4.2	4.2	21.3

¹ Our draft decision contained an error in accounting for capital contributions in the calculation of gross and net capex. AGN's revised proposal clarified the correct calculation (see AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, pp. 34–35).

² NGR, rr. 64(1), (5).

Category	2016–17	2017–18	2018–19	2019–20	2020–21	Total
Other non-distribution system	1.3	1.0	0.9	0.9	0.9	5.0
Escalation	0.5	1.2	2.3	3.5	4.4	11.9
Overheads	10.6	11.5	10.9	10.9	10.0	53.9
GROSS TOTAL CAPITAL EXPENDITURE	111.3	108.4	113.7	117.6	103.0	554.0
Contributions	0.6	0.7	0.7	0.9	0.7	3.6
NET TOTAL CAPITAL EXPENDITURE	110.6	107.8	113.0	116.7	102.3	550.5

Source: AER analysis.

Note: Numbers may not add due to rounding.

Table 6.3 shows AGN's revised capex compared with our approved allowance for each category. In coming to our position, we assessed AGN's forecast capex taking into account the available evidence and submissions from stakeholders.

As can be seen in Table 6.3, the main difference between AGN's revised capex and our alternative capex estimate for the 2016–21 access arrangement period is due to the position we have arrived at on growth assets, in particular, concerning the new extensions to Mount Barker and Two Wells. Our final decision is to include \$85.6 million (\$2014–15, unescalated) of growth assets capex in our alternative capex estimate. This is 25 per cent less than AGN's forecast expenditure of \$114.1 million (\$2014–15, unescalated) for its growth assets program.

This capex attachment discusses our assessment of those capex categories which AGN re-proposed in its revised proposal. These categories include capex for mains replacement, growth assets capex, augmentation capex, IT, capex for other distribution systems, capex for regulators and valves and escalation applied to new estate connections.

We accept the following capex items for the reasons set out in our draft decision:³

- Meter Replacement
- Telemetry
- Other non-distribution systems
- Contributions

³ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, pp. 6-25, 6-38 to 6-39, 6-52.

AGN accepted our method in the draft decision for calculating overheads for the capex forecast.⁴ We have used this method in calculating the overheads component of \$53.9 million (\$2014–15) in this final decision.

Table 6.3 Comparison of AER final decision and AGN's revised capital expenditure over the 2016–21 access arrangement period (\$million, 2014–15)

Category	Revised Proposal*	Approved(a)	Difference (\$millions)	Difference (%)
Mains replacement	277.2	277.2	0.0	0%
Meter replacement	17.1	17.1	0.0	0%
Augmentation	14.6	14.6	0.0	0%
Telemetry	1.1	1.1	0.0	0%
Regulators	11.3	11.0	-0.3	3%
IT	55.4	55.4	0.0	0%
Growth assets	114.1	85.6	-28.5	25%
Other distribution system	21.3	21.3	0.0	0%
Other non-distribution system	5.0	5.0	0.0	0%
Escalation	12.6	11.9	-0.7	5%
Overheads	55.4	53.9	-1.4	3%
GROSS TOTAL CAPITAL EXPENDITURE	585.0	554.0	-30.9	5%
Contributions	3.6	3.6	0.0	0%
NET TOTAL CAPITAL EXPENDITURE	581.4	550.5	-30.9	5%

Source: AER analysis.

Note: Revised proposal capex for each category in this table reflects the updated forecast provided by AGN on 1 March 2016.

6.2 AGN's revised proposal

6.2.1 2010–15 period

AGN proposed net capex of \$506.5 million for the 2010–16 period, where capex in 2015–16 is an estimate. Without the estimate of capex for 2015–16, AGN proposed

⁴ AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, p. 4.

\$389.7 million as conforming capex. We accept \$389.4 million as conforming capex for 2010–15, and will assess whether capex incurred in 2015–16 is conforming capex in the next access arrangement review.⁵

For 2010–16 AGN underspent capex by 14.7 per cent (\$87.8 million). This includes the 2015–16 estimate. Without the 2015–16 estimate, AGN underspent capex by 20.2 per cent (\$99.5 million).

Table 6.4 AGN's proposed capital expenditure over 2010–11 to 2015–16 (\$million, 2014–15)

Category	2010–11	2011–12	2012–13	2013–14	2014–15	2015–16(a)
Connections (Market expansion)	22.4	19.8	19.4	25.5	23.4	18.8
Mains replacement	15.5	23.6	36.5	45.5	48.6	61.9
Meter replacement	2.7	2.2	2.4	3.6	3.9	3.6
Augmentation	1.3	6.2	15.2	5.1	2.1	15.1
Telemetry	0.2	0.2	0.2	0.3	0.2	0.5
Regulators	0.2	0.3	0.9	2.7	3.2	0.7
IT	0.3	0.1	2.4	6.8	10.5	2.2
Other distribution system	0.0	1.6	0.8	3.2	1.3	1.7
Other non-distribution system	0.8	0.0	0.7	0.6	0.8	2.3
Overheads	0.0	5.9	7.5	7.9	9.0	10.3
GROSS TOTAL CAPITAL EXPENDITURE	43.3	59.8	86.0	101.3	103.0	117.1
Contributions	0.3	0.3	1.7	0.6	0.9	0.2
NET TOTAL CAPITAL EXPENDITURE	43.0	59.5	84.3	100.7	102.2	116.8

Source: AER analysis; AGN, *Response to AER information request - AER AGN 041A* [email to AER], 29 February 2016.

Note: (a) Capex for 2015–16 are estimates.

6.2.2 2016–21 access arrangement period

The revised proposal AGN submitted in January sought \$633.7 million (\$2014–15) total net forecast capex for 2016–21. AGN subsequently provided an updated capex

⁵ AGN's proposed and our accepted conforming capex for 2010–15 differ because we reclassified AGN's proposed expenditure relating to valve corrosion protection works as opex (see section 6.4.1).

forecast, which reduced the mains replacement component of its capex forecast from \$326.0 million to \$277.2 million (discussed further below). This reduced its total net capex forecast to \$581.4 million (\$2014–15) for the 2016–21 access arrangement period.

Table 6.5 AGN proposed capital expenditure over the 2016–21 access arrangement period (\$million, 2014–15)

Category	2016–17	2017–18	2018–19	2019–20	2020–21	Total
Mains replacement	61.1	50.4	56.8	57.7	51.2	277.2
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
IT	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
Escalation	0.5	1.3	2.3	4.2	4.3	12.6
Overheads	10.9	11.9	11.2	11.2	10.2	55.4
GROSS TOTAL CAPITAL EXPENDITURE	112.0	116.5	116.3	139.1	101.1	585.0
Contributions	0.6	0.7	0.7	0.9	0.7	3.6
NET TOTAL CAPITAL EXPENDITURE	111.3	115.9	115.6	138.2	100.4	581.4

Source: AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, pp. 34–35; AGN, *Revised access arrangement information: Attachment 8.8A: Capital expenditure forecast model* January 2016 (CONFIDENTIAL); AGN, *Mains Replacement Program Alternate Proposal to AER*, 1 March 2016.

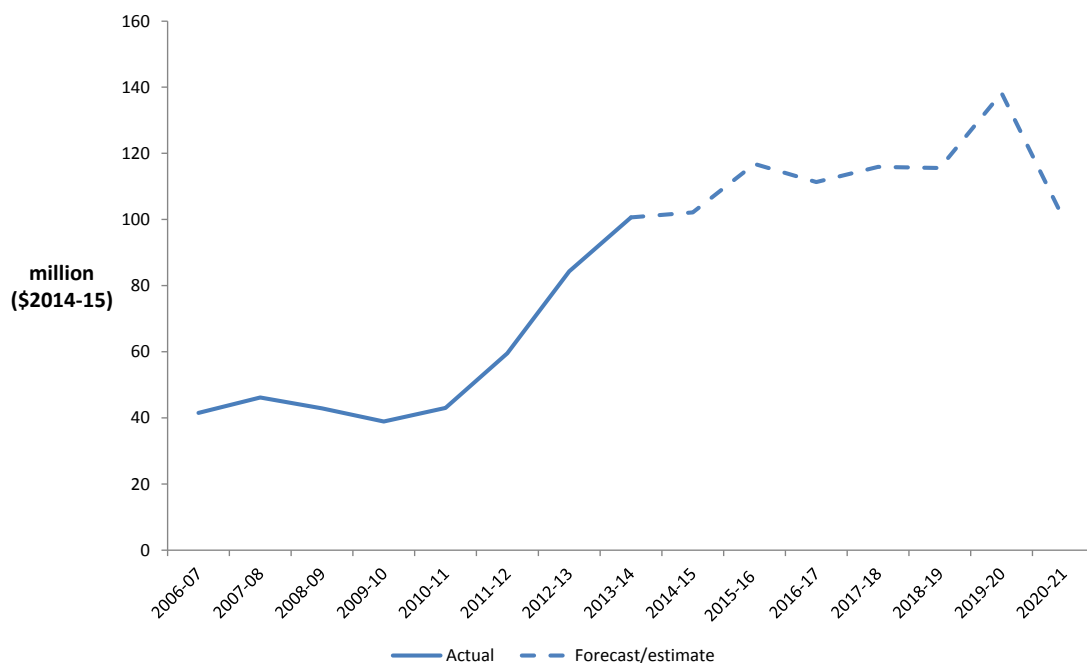
Several stakeholders raised their concerns regarding AGN's total capex forecast in its revised proposal. The Alternative Technology Association (ATA) and the Energy Consumers Coalition of SA (ECCSA) welcomed the reduction in capex in the draft

decision compared to AGN's initial proposal.⁶ However, the ATA considered the draft decision capex was still high in historical terms.⁷

Origin noted AGN proposed net capex of \$687.3 million in its initial proposal compared to \$392.6 million of net capital incurred in the 2010–15 period. Origin submitted that AGN did not provide adequate information to justify its mains replacement program. Origin considered the onus must be on AGN to demonstrate that any revised proposal is underpinned by prudent asset management systems and that these systems use robust and reliable data. Where this is not made available, Origin submitted that we must apply a conservative approach to determining an alternative value of conforming capex.⁸

Figure 6.1 illustrates that AGN's revised proposal continues the significant upward trend in total net capex into the 2016–21 access arrangement period.

Figure 6.1 Actual and forecast total net capex



Source: AER analysis.

Business SA noted AGN's capex program raises the value of its regulatory asset base (RAB) from \$1.02 billion in 2011/12 to \$1.98 billion in 2020/21. This is at odds with

⁶ ATA, *Re: AER's draft decision on Australian Gas Networks (SA) access arrangement*, 3 February 2016, p. 1; Energy Consumer's Coalition of SA, *A response to the Australian Energy Regulator draft decision on Australian Gas Networks AA2016 revenue reset*, February 2016, p. 2.

⁷ ATA, *Re: AER's draft decision on Australian Gas Networks (SA) access arrangement*, 3 February 2016, p. 1.

⁸ Origin, *Re: AGN revised access arrangement*, 4 February 2016, p. 1.

forecast declining demand for the gas it delivers and connection growth of just over one per cent per annum.⁹

The Consumer Challenge Panel (CCP) and ECCSA raised similar concerns on the effects of AGN's capex forecast on the RAB and supported our reductions to the total capex forecast in the draft decision.¹⁰ The CCP considered the capex forecast in the draft decision would moderate the concerning growth in AGN's RAB which is the driver for higher prices in future periods.¹¹ On the other hand, ECCSA considered the rising value of the RAB implied 'each customer is paying for an ever increasing value of assets despite using less and less gas' even with the draft decision's reductions to capex.¹²

6.3 AER's assessment approach

Under the NGR, we are required to make two decisions regarding AGN's capex. First, we are required to assess past capex and determine whether it meets the criteria set out in the NGR, with approved capex added to the starting capital base.¹³ Where capex meets these criteria, it is referred to as 'conforming capex'.¹⁴ Secondly, we are required to assess AGN's proposed forecast of required capex for the 2016–21 access arrangement period to determine whether it is also 'conforming capex'. The following sections set out our approach and the tools and techniques we employ in making these two decisions. We also need to take into account timing issues associated with the lag between actual capex data being available and the need to forecast an opening capital base. This is explained in the next section.

6.3.1 NGR requirements for conforming capital expenditure

- Capex is defined as costs and expenditure of a capital nature incurred to provide, or in providing, pipeline services.¹⁵ It is based on a forecast or estimate which must be supported by a statement of the basis of the forecast or estimate.¹⁶ Any forecast or estimate submitted must:
 - be arrived at on a reasonable basis; and

⁹ Business SA, *Submission on AER draft decision and AGN revised proposal*, 29 January 2016, pp. 1, 3–4.

¹⁰ Energy Consumer's Coalition of SA, *A response to the Australian Energy Regulator draft decision on Australian Gas Networks AA2016 revenue reset*, February 2016, pp. 2, 14; Consumer Challenge Panel, *Supplementary advice to AER from Consumer Challenge Panel 8 regarding the AER Draft Decision and Australian Gas Networks' (SA) Revised Access Arrangement 2016–21 proposal*, 31 March 2016, p. 4.

¹¹ Consumer Challenge Panel, *Supplementary advice to AER from Consumer Challenge Panel 8 regarding the AER Draft Decision and Australian Gas Networks' (SA) Revised Access Arrangement 2016–21 proposal*, 31 March 2016, p. 2.

¹² Energy Consumer's Coalition of SA, *A response to the Australian Energy Regulator draft decision on Australian Gas Networks AA2016 revenue reset*, February 2016, p. 3.

¹³ NGR, r. 77(2)(b).

¹⁴ NGR, r. 79.

¹⁵ NGR, r. 69.

¹⁶ NGR, r. 74(1).

- represent the best forecast or estimate possible in the circumstances.¹⁷
- Capex is conforming capital expenditure if it conforms with the criteria in rule 79 of the NGR. There are two essential criteria that must both be met under this rule:
 - the expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with good industry practice, to achieve the lowest sustainable cost of providing services; and
 - the expenditure must be justifiable on one of four grounds set out in rule 79(2) of the NGR.

The four grounds set out in rule 79(2) of the NGR can be summarised as follows. The capex must either:

- have an overall economic value that is positive;
- demonstrate an expected present value of the incremental revenue that exceeds the present value of the capex;
- be necessary to maintain and improve the safety of services, or maintain the integrity of services, or comply with a regulatory obligation or requirement, or maintain capacity to meet levels of demand existing at the time the capex is incurred; or
- be justifiable as a combination of the preceding two dot points.

Rule 79(3) of the NGR provides:

In deciding whether the overall economic value of capital expenditure is positive, consideration is to be given only to economic value directly accruing to the service provider, gas providers, users and end users.

We have limited discretion when making decisions under rule 79 of the NGR.¹⁸ This means that we must approve a particular element of the access arrangement proposal if we are satisfied that the element complies with the applicable requirements of the NGR and NGL and is consistent with any criteria set out in the NGR or NGL.¹⁹

6.3.2 Assessment of conforming capital expenditure in the previous period

In assessing AGN's proposed capex in the earlier access arrangement period, we reviewed AGN's supporting material. This included information on AGN's reasoning and, where relevant, business cases, audited regulatory accounts, and other relevant information. Using this information we assessed whether capex over the earlier access arrangement period was conforming capex and, in turn, whether that capex is

¹⁷ NGR, r. 74(2).

¹⁸ NGR, r. 79(6).

¹⁹ NGR, r. 40(2).

conforming capex under rule 79 that should be included in the opening capital base in accordance with rule 77(2)(b) of the NGR.

We do not approve certain information and forecasts provided by AGN if the information does not meet the requirements set out in the NGR.²⁰ We must exercise our economic regulatory functions in a manner that will or is likely to contribute to the achievement of the NGO.²¹ For instance, having regard to the NGO, we take the view that a prudent service provider will seek cost efficiencies through continuous improvements, and that customers ultimately share in these benefits. This also provides the service provider with a reasonable opportunity to recover at least its efficient costs in accordance with the revenue and pricing principles.

Although the capital base roll forward relates to the 2011–16 access arrangement period, we are also required to adjust for the difference between actual and forecast capex in the capital base.²² Generally, the final year of the previous access arrangement period is based on forecast capex (in this case, 2010–11). Therefore, our assessment of conforming capex includes the regulatory years for 2010–15. This is because:

- 2010–11 capex—when conducting the previous access arrangement review, we did not have actual capex for 2010–11. We therefore included in the capital base benchmark AGN's estimate of capex for 2010–11. Since actual capex is now available for 2010–11, we have assessed whether AGN's actual capex for 2010–11 is conforming capex under the NGR.²³ This conforming capex is now included in the capital base roll forward.²⁴
- 2011–15 capex—for this access arrangement review, we have the actual capex for 2011–15. We have assessed whether AGN's actual capex for 2011–15 is conforming capex under the NGR for inclusion in the capital base roll forward.²⁵
- 2015–16 capex—for this access arrangement review, we do not yet have actual capex for 2015–16. We have therefore included in the capital base roll forward AGN's estimate of capex for 2015–16. At the next access arrangement review, we will assess whether AGN's actual capex for 2015–16 is conforming capex under the NGR.²⁶

We assessed the key drivers for the capex to assess whether AGN's proposed capex in the projected capital base is conforming capex under rule 79 of the NGR. In doing so, we relied on the following information:

²⁰ For instance, r. 74 of the NGR requires estimates and forecasts to be made on a reasonable basis, among other things.

²¹ NGL, s. 28(1).

²² NGR, r. 77(2)(a).

²³ NGR, r. 79.

²⁴ NGR, r. 77(2)(b).

²⁵ NGR, rr. 77(2)(b), 79.

²⁶ NGR, r. 79.

- The access arrangement information – this document outlines AGN's program of capital expenditure and describes the main drivers of increased capital expenditure²⁷
- The Asset Management Plan, Mains Replacement Plan, Capacity Management Plan, Information Technology Plan, and other attachments which provided specific expenditure detail²⁸
- AGN's RIN template²⁹
- Business cases which detail expenditure requirements of specific projects³⁰
- AGN's tender and contract documentation³¹
- AGN's capex model.³²

We assessed the proposed capex, to determine whether it would be incurred by a prudent operator acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.³³ We also assessed whether the proposed capex is justified on one of the four grounds specified in rule 79(2) of the NGR.

For analysis purposes the capex was broken into categories depending on whether the expenditure is driven by:

- Growth in demand – extensions, connections, augmentation;
- Replacement on the basis of asset life, obsolescence, safety or regulatory obligations – mains, services, meters, regulators, city gates, IT, SCADA; or
- Other – new regulatory or safety obligations, opex or reliability improvements.

For each category of expenditure, we assess the scope, timing and cost of the proposed expenditure in forming a view on the prudence and efficiency of the expenditure. Our assessment also considers whether forecasts have been arrived at on a reasonable basis and represent the best forecast possible in the circumstances.

²⁷ AGN, *SA Access Arrangement Information*, July 2015; AGN, *Revised access arrangement information*, January 2016.

²⁸ AGN, *SA Access Arrangement Information*, July 2015, Attachments 8.1, 8.2, 8.3, 8.4, 8.5, 8.6, 8.7; AGN, *Revised access arrangement information*, January 2016, attachments 8.8A, 8.10, 8.13, 8.14, 8.15, 8.16, 8.18 (all CONFIDENTIAL).

²⁹ AGN, *SA Access Arrangement Information*, July 2015, MASTER Final RIN - AGN SA - Regulatory templates (Revised CC) – CONFIDENTIAL.xls; AGN, *Revised access arrangement information: Annual RIN 2014–15*, January 2016.

³⁰ AGN, *SA Access Arrangement Information*, July 2015, Attachment 7.1_Business Cases; AGN, *Revised access arrangement information: 7.1A Business cases*, January 2016.

³¹ AGN, *SA Access Arrangement Information*, July 2015, Attachment 8.6, Appendices 1a, 1b, 2a, 2b, 3a–3e, 5a, 6a.

³² AGN, *SA Access Arrangement Information*, July 2015, Attachment 8.8_SA Capex Model - Confidential Version.xls; AGN, *Revised access arrangement information: Attachment 8.8A: Capital expenditure forecast model*, January 2016 (CONFIDENTIAL).

³³ NGR, r. 79(1)(a).

6.3.3 Assessing forecast capex for the 2016–21 access arrangement period

The following sections set out our approach to assessing AGN's forecast capex for the 2016–21 access arrangement period. Our tools and techniques cover:

- assessing whether any outsourcing to third-parties reflect genuine arm's length arrangements
- assessing historical expenditure under the revealed cost approach
- how we compare costs against previous decisions we have made (benchmarking)
- consideration of technical engineering advice
- determining the appropriate estimate for equity raising costs.

Assessing competitive tender processes for outsourced activities

Outsourcing to specialist providers of a particular service is a common means by which businesses in the economy are able to gain access to economies of scale and scope and other efficiencies.

Where AGN has used tendered rates as the basis of proposed unit costs, we relied on our approach to assessing outsourcing arrangements.³⁴ The first stage of the conceptual framework is a 'presumption threshold' designed to be an initial filter to determine which contracts can be presumed to reflect efficient costs that would be incurred by a prudent operator.³⁵

In undertaking this 'presumption threshold' assessment, we consider:

- Did the service provider have an incentive to agree to non-arm's length terms at the time the contract was negotiated (or at its most recent re-negotiation)?
- If yes, was a competitive open tender process conducted in a competitive market?

In the absence of an incentive to agree to non-arm's length terms, we consider it reasonable to presume a contract price reflects efficient costs. We also consider this presumption to be reasonable where an incentive to agree to non-arm's length terms exists but the contract was the outcome of a competitive open tender process in a competitive market.³⁶

Where an arrangement 'passes' the presumption threshold, we consider the starting point for setting future expenditure should be the contract price itself, with limited further examination. This further examination involves checking whether the contract

³⁴ AER, *Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 9–10.

³⁵ NGR, r. 71(1).

³⁶ NGR, r. 71(1).

wholly relates to the relevant services and whether the contract price already compensates for risks or costs provided for elsewhere in the building blocks.

Revealed cost approach

The revealed cost approach considers information revealed by the past performance of a gas business. Under the ex ante regime, gas businesses are rewarded for spending less capex than allowed by the regulator. This incentive enables us to place some reliance on the historical costs of a gas business when reviewing its forecast capex. We used historical costs and volumes as an indicator of efficient costs and volumes for certain categories of capex in this final decision. In particular, we used historical total costs, unit costs and volumes in assessing connections, mains and services replacements, meter replacements, and IT.

The revealed cost approach is an accepted industry practice. Many gas businesses, including AGN, have used this approach as a basis to forecast expenditure proposals. We have also used this approach previously in our assessment of access arrangement proposals for the Victorian and NSW gas businesses.

Benchmarking against the other businesses' proposed unit costs and volumes

We also conducted comparative analysis of unit costs AGN has used to develop its capex forecast. Comparing the costs incurred by one regulated entity against the costs incurred by other regulated entities in similar circumstances, and using the comparison to assess the efficiency and prudence of those costs, is known as 'benchmarking'. We consider that the use of benchmarking to assess whether capex is conforming is consistent with the requirements of the NGR.

We undertook high level benchmarking of a selection of AGN's unit costs against similar unit costs of the Victorian gas businesses. Where required some adjustment for compositional difference was made. This comparison was used for assessing connections, mains and services replacements, and meter renewals and upgrade.

Where this benchmarking indicated that AGN's capex may not be efficient, we undertook a detailed review of AGN's proposal. Our detailed review involved consideration of relevant documentation and the impact of factors expected to differ from the past and/or from the Victorian gas businesses.

We recognise that forecast efficient costs may legitimately depart from those revealed through past performance, and compared with other gas businesses. For example, gas businesses may discover more efficient processes over time. The gas businesses may propose that they can best achieve their safety, reliability or regulatory obligations by incurring expenditure to implement new, more efficient processes, and include such expenditure in their proposed forecast capex. We consider it likely that a prudent service provider, acting efficiently, would only change operating processes (from revealed, or otherwise efficient processes) if they are likely to result in efficiency gains (in the absence of any information to suggest other reasons for the change). Where we

consider that future cost savings should result from capex investments, we have taken this into consideration in determining our alternative opex estimate.

Specialist technical advice

We drew on engineering and other technical expertise within the AER to assist with our review on the prudence and efficiency of AGN's proposed mains replacement program.

We also engaged an engineering consultant, Sleeman Consulting, to provide us with specialist technical advice on the prudence and efficiency of AGN's proposed augmentation, regulators and valves, and other distribution system capex.³⁷

Cash flow analysis for equity raising costs

To determine the amount of equity raising costs, we have undertaken an assessment of benchmark cash flows calculated in the post-tax revenue model. Under this method, a prudent service provider acting efficiently would first exhaust the cheapest sources of funding, such as internal cash flows, before using more expensive external sources of funding such as equity financing. The cash flow modelling approach used by the AER incorporates this assumption to determine if any external equity financing would be required based on the AER's capex forecast for AGN. For further discussion see Attachment 3, section 3.4.1.

6.3.4 Interrelationships

In assessing AGN's total forecast capex we took into account other components of its proposal, including:

- the trade-off between potential capex and opex solutions in our assessment of AGN's proposed capex.
- any change in the capitalisation policy applied between the current access arrangement period and the 2016–21 access arrangement period.

6.4 Reasons for final decision

6.4.1 Conforming capital expenditure for 2010–15

AGN proposed net capex of \$506.5 million for the 2010–16 period, where capex in 2015–16 is an estimate. Without the estimate of capex for 2015–16, AGN has proposed \$389.7 million as conforming capex. We accept \$389.4 million as conforming capex for 2010–15, and will assess whether capex incurred in 2015–16 is conforming capex in the next access arrangement review.

³⁷ Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016.

As set out in our draft decision, we considered the following factors in reaching this view:

- AGN's network capex was \$7.7 million (15.1 per cent) under the Essential Services Commission of South Australia (ESCOSA) approved amount of \$51 million (\$2014–15) for 2010–11.³⁸
- AGN's network capex was \$91.8 million (20.8 per cent) under the AER approved amount of \$441.6 million for 2011–15.³⁹
- AGN spent less than our forecast on its network in six out of nine categories during the 2010–15 period. In five categories, the underspend was greater than 20 per cent below forecast.
- The largest underspends in the 2010–15 period⁴⁰ occurred in the connections/growth assets, other distribution, and meter replacement categories:⁴¹
 - In the connections/growth assets category, AGN spent \$50.2 million less than forecast due to a smaller volume of new connections occurring than was approved.
 - In the other distribution category, AGN spent \$35.2 million less than forecast due a change in the costs captured in this category. Formerly this category captured the costs of complying with new requirements for road works and reinstatement. These costs were instead allocated directly to the augmentation, growth and mains replacement categories.
 - In the meter replacement category, AGN spent \$3.7 million less than our estimate due to lower volumes of domestic meters being replaced than forecast, which AGN submitted reflected an updated view of the required replacement program for various meter family types.
- The largest overspends in the 2010–15 period occurred in information technology (IT), augmentation, and regulators categories:⁴²
 - In the IT category, AGN exceeded the forecast by \$10.1 million due to the development and implementation of AGN's Enterprise Asset Management (EAM) system, the requirements/complexity of which was not forecast at the time the benchmarks were set.

³⁸ Envestra, *South Australia Access Arrangement Information*, 1 October 2010, Table 3.6, p. 36; AGN, *Response to AER information request - AER AGN 041A* [email to AER], 29 February 2016.

³⁹ AER, *Access arrangement information: Envestra's South Australian gas distribution network: Amended by order of the Australian Competition Tribunal*, July 2011, Table 4.1, p. 10; AGN, *Response to AER information request - AER AGN 041A* [email to AER], 29 February 2016.

⁴⁰ Only the 2011–15 period comparison by category has been presented as the ESCOSA decision was not made on the same category basis and was not in the same level of detail as the AER 2011–16 Access Arrangement Decision.

⁴¹ AGN, *SA Access Arrangement Information*, July 2015, p. 78.

⁴² AGN, *SA Access Arrangement Information*, July 2015, p. 78.

- In the augmentation category, AGN exceeded the forecast by \$2.3 million due to the completion of additional augmentation projects than were forecast, including projects in Tapley's Hill Road, Gawler and Salisbury.
- In the regulators category, AGN exceeded the forecast by \$4.1 million due to a new national design standard requiring more expensive components and installation costs, increased decommissioning costs of existing regulators and valves due to greater traffic management requirements and higher than expected instances of asbestos.

The numbers set out above differ slightly to those in the draft decision. This is due to updates for 2014–15 and 2015–16 and to a revision in the CPI used to convert to real dollars. In addition, AGN stated it classified expenditure relating to valve corrosion protection works as capex in the 2011–16 period (although our final decision for the previous access arrangement review included this amount in the opex allowance).⁴³ AGN has agreed with us that this expenditure should be removed from conforming capex to be consistent with our final decision for the previous access arrangement review (see also section 6.4.2.3).⁴⁴

6.4.2 Conforming capital expenditure for the 2016–21 access arrangement period

We approve \$550.5 million (\$2014–15) of AGN's proposed \$581.4 million (\$2014–15) total net capex for the 2016–21 access arrangement period as conforming capex under rule 79 of the NGR.

The rest of this attachment sets out our final decision on those capex items which AGN has re-proposed in its revised proposal.

6.4.2.1 Mains replacement

Distribution mains are the pipes which convey gas to service pipes at each end user point. AGN's distribution mains replacement program consists of proactive and reactive replacement programs. It involves the replacement of aging cast iron (CI), unprotected steel pipe (UPS) mains and high density polyethylene (HDPE) mains.

In January 2016, AGN proposed \$326.0 million of mains replacement capex to replace 1265 kilometres of mains pipes in its revised proposal. This was \$43.9 million less than its initial proposal of \$369.9 million. However, on 1 March 2016, AGN informed us that it had further reduced its proposal by \$48.8 million to \$277.2 million (\$2014–15, unescalated) to replace 1072 kilometres of main pipes.⁴⁵ This modified figure of 1072

⁴³ AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, p. 20.

⁴⁴ AGN, *Response to AER information request: AER AGN 034A: Capex - Regulators - Valve corrosion protection* [email to AER], 17 February 2016.

⁴⁵ AGN, *Mains Replacement Program Alternate Proposal to AER*, 1 March 2016, p. 2.

kilometres of mains replacement reflects the volume set for the current access arrangement period.

For the reasons below, we accept AGN's proposal of \$277.2 million for mains replacement capex (which includes multi-user service inlets). We are satisfied that it is conforming capex under rule 79.

We consider AGN's proposal to replace 1072 kilometres of mains is sufficiently proximate to our alternative estimate of 985 kilometres of mains replacement. Overall, our estimate supports the conclusion that, over the 2016-21 access arrangement period, the scale of AGN's proposal and the associated \$277.2 million it has proposed is that which a prudent service provider would incur, acting efficiently. We arrived at our estimate by applying an alternative approach to determine the kilometres of main pipes to replace over the next access arrangement period. This approach is based on observing the historical trend in cracks on pipe mains, where the mains identified for replacement are those that demonstrate deterioration by exhibiting an increasing number of cracks over the current access arrangement period. Our technical analysis is set out in the confidential appendix (Appendix A).

In accepting AGN's proposal of 1072 kilometres of mains replacement, our expectation is that AGN will undertake CBD replacement works over the 2016-21 access arrangement period. We note that our alternative estimate is predicated on AGN undertaking CBD replacement works. AGN has indicated throughout its revised proposal that replacement of CI mains in the CBD is a priority given the risks associated with these pipes.⁴⁶ We also note that the South Australian Office of the Technical Regulator (OTR) also regards CBD replacement works as a priority and has for some time. In this regard, we note the OTR's concerns that AGN has failed to carry over outstanding block mains replacement in the Adelaide CBD from 2012/13 and 2013/14.⁴⁷ We expect to specifically review conforming capex for mains replacement in the next access arrangement period.

We also accept AGN's revised unit rates across all categories of mains replacement and AGN's revised proposal of \$10 million for its HDPE camera inspection and repair program, which forms part of AGN's wider risk mitigation strategy. Our analysis of AGN's revised unit rates is set out in the confidential appendix and we discuss below our analysis of the proposed capex for the HDPE camera.

However, despite accepting AGN's proposed mains replacement program, we have some residual concerns that are worth noting. These concerns do not detract from nor do they outweigh the position we have arrived at to accept AGN's proposal. However, it is likely that they will underpin our assessment of the mains replacement capex to be

⁴⁶ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, pp. 23, 28–29.

⁴⁷ In the OTR's 2014/15 Gas annual report, the OTR has expressed concerns that AGN has failed to carry over the outstanding block mains replacement in the Adelaide CBD not undertaken in 2012/13 and 2013/14. See: Office of the Technical Regulator, *Annual report of the technical regulator: Gas 2014/15*, 2015, p. 15.

included in the opening capital base at the next access arrangement review. These concerns are set out in Appendix B.

Assessment

In its letter on 1 March 2016, AGN revised its mains replacement program and provided updated figures, including the volume of mains by type, to be replaced over the 2016-21 access arrangement period. This revision followed the Government of South Australia's⁴⁸ submission about AGN's ability to deliver the proposed 1265 kilometres of mains replacement, given the complexity of CBD mains replacement that is included as part of its proposal.

AGN's revision is to replace 659 kilometres of HDPE mains. This is 64 per cent greater than its initial proposal. The 659 kilometres of HDPE mains replacement is associated with 180 kilometres of HDPE class 250 and 479 kilometres of HDPE class 575. There is also a corresponding reduction in AGN's proposed CI/UPS mains replacement to 351 kilometres, 56 per cent lower than its initial proposal. This is summarised in Table 6.6.

Table 6.6 AGN proposed mains replacement programs (\$2014–15, un-escalated direct costs)

	Initial proposal		Modified proposal		Change (%)	
	Km to be replaced	Total cost (\$m, \$2014–15)	Km to be replaced	Total cost (\$m, \$2014–15)	Volume	Cost
CI/UPS block replacement	796.5	180.4	351.1	91.6	-55.9	-49.2
Services replacement post 2004-12 CI/UPS block replacement	n/a	14.4	n/a	14.7	n/a	2.3
HDPE mains replacement	401.0	127.9	659.0	128.4	64.3	0.4
MP trunk mains replacement	62.0	42.5	62.0	42.5	0.0	0.0
Total kilometres/cost	1273.0	369.9	1072.1	277.2	-15.8	-25.1

Source: AGN, *SA Access Arrangement Information, Attachment 8.8_SA Capex Model -Confidential Version.xls*, July 2015; *Initial proposal, Attachment 8.2 Mains Replacement Program (MRP)*, pp. 38–39; AGN, *AGN, Mains Replacement Program Alternate Proposal to AER*, 1 March 2016.

Note:

- (a) This block replacement relates to service replacements in multi-user sites not undertaken in 2004-12. These were deferred because of their complexity, and time required to replace them such that these sites could be replaced as a contract package on a stand-alone basis (see Mains Replacement Program of initial proposal, attachment 8.2, p. 18)
- (b) Total kilometres and cost in the initial proposal includes ad hoc mains replacement

⁴⁸ South Australian Government, *Submission on Australian Gas Networks, Access Arrangement 2016–21, Draft Decision*, 24 February 2016, p. 2.

In comparison, the mains replacement AGN proposed in its revised proposal in January 2016 was for \$326.0 million capex (\$2014–15, unescalated) to replace 1265 kilometres of mains. This is approximately 11 per cent lower than its initial proposal of \$369.9 million to replace 1273 kilometres. In support of its proposal, AGN provided, amongst other things, a qualitative risk assessment against particular safety standards, a risk prioritisation model and a report by Jacobs in support of its program.⁴⁹ AGN again referred to these materials in support of its proposal in its letter of 1 March 2016.⁵⁰

In addition to the Government of South Australia's submission noted above, we received a number of submissions that questioned whether the entirety of AGN's proposed mains replacement program and other risk mitigation measures were required.⁵¹ The South Australian Council of Social Service (SACOSS) considered that in assessing the safety case for mains replacement, the AER should look at the totality of evidence and to the reasonableness of the basis for the projects.⁵² The CCP advised that an assessment approach based on the risk rating of individual program components (risk of mains in each suburb) may be more appropriate than AGN's aggregated approach.⁵³

SACOSS and ECCSA noted that the mains replacement program should lead to efficiencies in operating expenditure, which the AER should take into account.⁵⁴ We have considered the impact of the mains replacement program on unaccounted for gas in our operating expenditure attachment.⁵⁵

Overall, we assess that AGN provided more information in its revised proposal than it did in its initial proposal about how it assesses the risks associated with its main pipes and the reasoning for its proposed capex and kilometres over the next access

⁴⁹ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, pp. 16–37; AGN, *Revised proposal Attachment 8.14: AGN risk prioritisation model*, January 2016; Jacobs, *Mains Replacement Program Review*, January 2016, provided as Attachment 8.11 to AGN's Revised AA Proposal.

⁵⁰ AGN, *Mains Replacement Program Alternate Proposal to AER*, 1 March 2016, p. 1.

⁵¹ SACOSS, *Submission to the AER in response to AGN's revised regulatory proposal for the 2016 - 2021 access arrangements*, February 2016, pp. 4–7; Consumer Challenge Panel, *Supplementary advice to AER from Consumer Challenge Panel 8 regarding the AER Draft Decision and Australian Gas Networks' (SA) Revised Access Arrangement 2016–21 proposal*, 31 March 2016, p. 3; Origin Energy, *Submission to the AER in response to AGN's revised regulatory proposal for the 2016 - 2021 access arrangements*, February 2016, p. 1; AGL, *Submission to the AER in response to AGN's revised regulatory proposal for the 2016 - 2021 access arrangements*, February 2016, p. 2; Energy Consumer's Coalition of SA, *A response to the Australian Energy Regulator draft decision on Australian Gas Networks AA2016 revenue reset*, February 2016, pp. 19–20.

⁵² SACOSS, *Submission to the AER in response to AGN's revised regulatory proposal for the 2016 - 2021 access arrangements*, February 2016, p. 6.

⁵³ Consumer Challenge Panel, *Supplementary advice to AER from Consumer Challenge Panel 8 regarding the AER Draft Decision and Australian Gas Networks' (SA) Revised Access Arrangement 2016–21 proposal*, 31 March 2016, p. 3.

⁵⁴ SACOSS, *Submission to the AER in response to AGN's revised regulatory proposal for the 2016 - 2021 access arrangements*, February 2016, pp. 8–9; Energy Consumer's Coalition of SA, *A response to the Australian Energy Regulator draft decision on Australian Gas Networks AA2016 revenue reset*, February 2016, p. 19.

⁵⁵ AER, *Final decision Australian Gas Networks access arrangement: Attachment 7 - operating expenditure*, April 2016, pp. 25–26.

arrangement period. In our draft decision, we took the view that in its initial proposal, AGN did not provide a rigorous (quantitative) risk assessment to establish that its proposed rate of mains replacement over the 2016-21 period was prudent and efficient. Our alternative estimate of mains replacement in the draft decision reduced AGN's initial proposal by 50 percent, i.e. \$167.7 million to replace 577 kilometres of main pipes over the 2016-21 access arrangement period.⁵⁶

We find that AGN's proposal of 1072 kilometres of mains replacement is that which a prudent operator, acting efficiently, would undertake in the circumstances because:

- our alternative estimate of 985 kilometres, which reflects what we consider a prudent operator acting efficiently would do in determining the kilometres of mains to be replaced over the next access arrangement period, supports the scale of AGN's proposal; and
- AGN has demonstrated it is capable of delivering these kilometres, as 1072 kilometres represents the benchmark amount we set over the current period (which AGN has exceeded by 100 kilometres).

We agree with the Government of South Australia that the complexity of the CBD replacement works is likely to impact on AGN's ability to deliver even more than its historical replacement rate. It follows that AGN's delivery capability is likely to be less than the 1265 kilometres of mains replacement AGN proposed in January 2016. AGN submits that some of the proposed CBD replacement works is of greater complexity than the CBD replacement works undertaken in the current access arrangement period.⁵⁷ Further, AGN notes that CBD mains replacement has been delayed to date because this replacement requires 'significant preparatory design and consultation work'.⁵⁸

We also note that the OTR has indicated support for our position to accept AGN's proposal of 1072 kilometres of mains replacement.⁵⁹

Alternative approach and estimate

Our alternative estimate for the volume of mains replacement over the 2016–21 access arrangement period is for a total of 985 kilometres. This includes 456 kilometres of HDPE mains and 529 kilometres of CI mains (including the CBD). A detailed description of our alternative approach is provided in the confidential appendix. We consider that our alternative estimate supports the scale of AGN's modified mains

⁵⁶ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, p. 35.

⁵⁷ AGN, *SA Access Arrangement Information, Attachment 8.6 SA Unit Rates 300615*, July 2015, pp. 33–34.

⁵⁸ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 13.

⁵⁹ File note of conversation with representatives from the Office of the Technical Regulator, 9 February 2016 and 11 March 2016.

replacement proposal of 1072 kilometres. As we have also accepted AGN's revised unit rates, we have not calculated an alternative capex amount.

In coming to our alternative approach, we recognise⁶⁰ that there are risks associated with CI and HDPE main pipes and that these risks need to be mitigated. We also recognise that some interested parties have submitted that an alternative mains replacement estimate should be proportionate to those risks, as discussed above. We therefore extensively reviewed AGN's risk prioritisation model which includes nine years of crack data as well as other information on the condition of AGN's unreplaced main pipes. We also received additional data from AGN on annualised crack history, provided in response to our information requests.⁶¹ From reviewing the data we noted the following:

- Over the current access arrangement period, 2011–12 to 2015–16, additional cracks on HDPE main pipes have trended downwards in the suburbs AGN identified as high risk, and additional cracks on CI mains have been stable, on average.
- When we examine only those HDPE and CI main pipes that exhibit a relatively high number of cracks per kilometre, we observe that the number of additional cracks on both types of mains trends upwards.

Having regard to these trends, we developed our alternative approach. Our alternative approach assesses the crack rate of main pipes in each suburb relative to the overall trend and identifies those main pipes that show deterioration in condition, as demonstrated by an increasing number of cracks over time.⁶² In particular, we consider that a prudent operator acting efficiently would review the conditions of its pipes over time, and replace those that demonstrate a worsening of condition relative to the overall trend.

AGN's HDPE camera investigation and repairs program (SA52)

We are satisfied that AGN's revised capex proposal of \$10.0 million (\$2014–15, unescalated) for a HDPE in-line camera and repairs program (SA52) on its class 575 HDPE mains is conforming capex under rule 79 of the NGR.⁶³

⁶⁰ For example, AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure - Confidential appendix A*, November 2015, pp. 15–16, Jacobs, *Mains Replacement Program Review*, January 2016, provided as Attachment 8.11 to AGN's Revised AA Proposal.

⁶¹ AGN, *Response to information request AER AGN 033* [email to AER], February 2016.

⁶² In our Draft Decision, we determined an alternative estimate based on historical leakage data. In its revised proposal, AGN explained that a crack typically releases larger volumes of gas than a leak at a pipe joint, and therefore carries a greater likelihood of resulting in an event that causes serious harm. After reviewing AGN's claims, we accept that cracks, rather than leakages, are more prone to fatality incidents and have used historical crack data to ratify this shortcoming. See: AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 64.

⁶³ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, pp. 43–44.

AGN submitted that the HDPE in-line camera is intended to mitigate the risk of incidents by identifying squeeze-off locations so that repair or piecemeal replacement can be done at identified sites.⁶⁴ The program forms part of AGN's wider risk mitigation strategy.

AGN's revised capex for this program is a \$1.6 million reduction from its initial proposal. AGN submits that this reduction reflects an increase in AGN's proposed volume of HDPE replacement over the next access arrangement period, reducing the length of mains that will need to be subject to internal camera inspection and repairs.⁶⁵

In our draft decision, we did not accept the capex proposed for this program in the absence of a quantitative business case or a cost–benefit analysis. However we did note that a HDPE camera could be a prudent investment.⁶⁶

In support of its revised proposal for this program, AGN provided the results of a trial run of its in-line camera project which started in September 2015. The results were based on 2.5 km of a 9 km HDPE pilot precinct. AGN used the results from the pilot to update its expenditure forecasts to more accurately reflect realistic estimates of costs.⁶⁷ We are satisfied that the additional material provided by AGN quantifies the cost of the program⁶⁸ and that the program would assist in deferring mains replacement at a relatively low cost.

6.4.2.2 Augmentation

Network augmentation capex is directed at increasing the capacity of the existing network to meet the demand of existing and future customers. Augmentation capex is required to maintain gas pressure and minimise the risk of gas outages. AGN submitted that its augmentation capex is necessary under the NGR.⁶⁹

We accept AGN's revised proposed expenditure of \$14.6 million (\$2014–15, unescalated) for augmentation capex. We consider this is conforming capex under rule 79 of the NGR. AGN proposed \$17.9 million (\$2014–15, unescalated) of augmentation capex in its initial proposal.

⁶⁴ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 43.

⁶⁵ AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network, Attachment 7.1A Business Cases for operating and capital expenditure SA52*, January 2016, p. 4.

⁶⁶ In response to our request for a business case for the HDPE camera, AGN commented on how the HDPE camera forms part of its prudent risk management strategy but did not provide a quantitative business case (AER, *Info request to AGN from the AER no. 23* [email to AGN], 18 September 2015); AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, p. 6-6.

⁶⁷ AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network, Attachment 7.1A Business Cases for operating and capital expenditure SA52*, January 2016, pp. 4–5, 10.

⁶⁸ AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network, Attachment 7.1A Business Cases for operating and capital expenditure SA52*, January 2016, pp. 8–9.

⁶⁹ NGR, r. 79(2)(c). AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, pp. 18–19; AGN, *Access arrangement information*, July 2016, pp. 143–145.

Our draft decision included \$4.1 million (\$2014–15, unescalated) of augmentation capex in our capex forecast, as we considered two projects (coded SA21 and SA71) totalling \$10.5 million (\$2014–15, unescalated) were not conforming capex. We also reclassified one project (coded SA21a) totalling \$3.3 million (\$2014–15, unescalated) as opex.

In its revised proposal, AGN agreed with the reclassification of the SA21a project as opex. AGN did not agree with the draft decision to remove the SA21 and SA71 projects from conforming capex and provided additional material to support its proposal.⁷⁰ The sections below contain our consideration of the SA21 and SA71 projects.

Southern Transmission Pipeline (SA21)

We are satisfied AGN's proposed capex of \$7.5 million (\$2014–15, unescalated) for the Southern Transmission Pipelines project (SA21) is conforming capex under rule 79.⁷¹ In coming to this view we took into account the advice we received from Sleeman Consulting.⁷²

Our draft decision did not consider the capex for this project was conforming capex under rule 79. Based on advice from Sleeman Consulting, we considered the levels of corrosion AGN found in its survey of the pipelines were considerably below threshold levels that would necessitate capital works. We considered the pipelines will remain fit for purpose, and that a burst failure is unlikely.⁷³

In the revised proposal, AGN again proposed \$7.5 million (\$2014–15, unescalated) for the SA21 project, but deferred it by two years to 2018–19 and 2019–20.⁷⁴ AGN provided the additional analysis demonstrating that the M21 and M53 pipelines are nearing the end of their useful lives. AGN also compared the forecast expenditure for SA21 with the cost of other options; namely the cost of deferring the replacement until the 2021–26 period and increasing monitoring in the 2016–21 period. AGN's options analysis suggests SA21 is the lowest cost option and AGN submitted this is consistent with the actions of a prudent and efficient network operator.⁷⁵

We liaised with AGN regarding the information it provided in the revised proposal. For example, we asked AGN to justify its use of the corrosion rate of 0.4 mm per year for the pipelines, which was an important input into determining the remaining lives of the

⁷⁰ AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, , p. 18.

⁷¹ NGR, r. 79(2)(c)(i) and (ii).

⁷² Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016, section 2.1.

⁷³ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, p. 6-26.

⁷⁴ AGN's revised capex model incorrectly included forecast capex for SA21 in the years 2016–17 and 2017–18. We corrected this error in our modelling and assessed the forecast capex for SA21 as proposed for the years 2018–19 and 2019–20. AGN, *Response to AER Aust Gas Networks 050: Augmentation forecast* [email to AER], 23 March 2016.

⁷⁵ AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, p. 19.

pipelines.⁷⁶ Sleeman Consulting noted that the 0.4 mm per year figure is recommended for use in determining reinspection intervals. Sleeman Consulting also noted that corrosion rates are unpredictable and may be higher under disbonded coating than in the case of bare steel. Hence, Sleeman Consulting considered the manner in which AGN utilised the 0.4 mm per year figure is reasonable for planning purposes.⁷⁷ Sleeman Consulting also considered other aspects of AGN's calculation of the pipelines' remaining life is reasonable, and that it is reasonable that the pipelines be replaced in the 2016–21 period.⁷⁸ Having regard to Sleeman Consulting's advice, we have included this expenditure in conforming capex for the 2016–21 period.

We also liaised extensively with AGN regarding the statistical analysis it used for estimating the cost of its alternative option to SA21.⁷⁹ We are satisfied AGN's derivation of its options analysis is rigorous and uses reasonable assumptions. For example, we asked AGN to justify why it would require 20 excavations per year in its alternative option. AGN stated that this is to manage risk to the pipelines at an acceptable level, given how widespread the corrosion is on the M21 and M53 pipelines.⁸⁰ We understand choosing the level of risk for any project requires judgement on the part of the planner. For example, we estimate that 12 excavations per year or below would result in the alternative option having a lower net present value (NPV) than SA21. This results in a higher level of risk for the pipelines.⁸¹ Given how widespread corrosion is in the pipelines and the potential for accelerating rates of corrosion (given the pipelines' age), we consider AGN has adopted a reasonable level of risk in its options analysis.

Murray Bridge augmentation (SA71)

We are satisfied AGN's proposed capex of \$3.0 million (\$2014–15, unescalated) for the Murray Bridge augmentation (SA71) is conforming capex under rule 79.⁸² However, we consider AGN can defer this expenditure within the 2016-21 access arrangement period, to 2019–20 and 2020–21. In coming to this view we took into account the advice we received from Sleeman Consulting.⁸³

⁷⁶ AGN, *Response to AER Aust Gas Networks 038: SA21 and SA71* [email to AER], 12 February 2016, attachment 1.

⁷⁷ Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016, section 2.1.3(iii).

⁷⁸ Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016, section 2.1.3(viii).

⁷⁹ AGN, *Response to AER Aust Gas Networks 044: M21 and M53* [email to AER], 1 March 2016; AGN, *Response to AER Aust Gas Networks 036: Replacement of M21 and M53 (SA21)* [email to AER], 14 February 2016.

⁸⁰ More specifically, 20 excavations per year results in the average pit depth having a margin of error of 20 per cent, which AGN considered an acceptable level of risk. See AGN, *Response to AER Aust Gas Networks 044: M21 and M53* [email to AER], 1 March 2016, p. 3; AGN, *Response to AER Aust Gas Networks 036: Replacement of M21 and M53 (SA21)* [email to AER], 14 February 2016, p. 3 (PUBLIC VERSION).

⁸¹ We calculated a margin of error of approximately 27 per cent.

⁸² NGR, rr. 79(2)(c)(i) and (ii).

⁸³ Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016, section 2.2.

Our draft decision did not consider the proposed capex for this project was conforming capex under rule 79. We noted AGN expected 250–300 new connections per year due to new developments in the Murray Bridge township. We considered AGN's annual forecast number of new connections was overstated based on historical rates. We also agreed with Sleeman Consulting's advice that the infrastructure currently in place could accommodate growth in the Murray Bridge township.⁸⁴

In its revised proposal, AGN clarified that future growth in the Murray Bridge and Monarto townships is not the main driver for the project. Rather, the main driver is that the pipeline currently in place has reached capacity and cannot accommodate organic growth in the Murray Bridge region.⁸⁵

AGN also confirmed it can operate the existing pipeline at a higher pressure than the current level of 1.65MPa. However, the pressure increase on the existing pipeline servicing the Murray Bridge township is limited by the current licenced maximum allowable pressure of 1.8 MPa. Under this condition, AGN stated it can increase the operating pressure to 1.75 MPa at 'relatively low' cost.⁸⁶ AGN stated the pressure of the downstream supply to Murray Bridge will fall below the acceptable minimum by 2020–21 under this scenario.

AGN also submitted it can increase the maximum allowable operating pressure of the existing pipeline to 1.89 MPa at a cost of \$1.5 million (\$2014–15). AGN stated SA71 would still need to be completed by 2022 under this scenario. AGN also submitted analysis showing this option has a higher NPV than completing SA71 by 2019, as it proposed in the revised proposal.⁸⁷

Sleeman Consulting considered AGN's assumed annual peak demand growth of 50m³/hr per annum is fair and reasonable as it reflects historic growth.⁸⁸ Based on our analysis of AGN's modelling, we agree that the 50 m³/hr per annum figure for peak demand growth is appropriate for planning and network modelling for the Murray Bridge area.⁸⁹

We also note that planning for the SA71 project is highly sensitive to demand from the four Tariff D customers in Murray Bridge, who account for approximately 90 per cent of

⁸⁴ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, p. 6-27.

⁸⁵ AGN, *Revised access arrangement information: Attachment 7.1A: Business cases: Addendum to business case SA71*, January 2016, pp. 3–5.

⁸⁶ AGN, *Revised access arrangement information: Attachment 7.1A: Business cases: Addendum to business case SA71*, January 2016, pp. 5–6.

⁸⁷ AGN, *Revised access arrangement information: Attachment 7.1A: Business cases: Addendum to business case SA71*, January 2016, pp. 5–7.

⁸⁸ Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016, section 2.2.3.

⁸⁹ AGN, *Response to AER Australian Gas Networks 048 - Murray Bridge* [email to AER], 23 March 2016

peak hourly demand.⁹⁰ Sleeman Consulting noted closure or disconnection of a Tariff D customer could defer the need for augmentation further.⁹¹ On the other hand, AGN submitted small changes in their demand profiles could bring forward the augmentation requirement for Murray Bridge.⁹²

Given the organic growth in Murray Bridge and the sensitivity of peak demand to the Tariff D customers, we consider that AGN has provided sufficient evidence to justify capex for SA71 in the 2016–21 period.

Regarding the existing pipeline, Sleeman Consulting agreed with AGN that upgrading the maximum allowable operating pressure to 1.89 MPa is not justified. However, Sleeman Consulting considered AGN should implement the low cost initiative of increasing the operating pressure of the existing Murray Bridge pipeline to 1.75 MPa.⁹³ We agree with Sleeman Consulting as this would result in NPV savings from deferring SA71 by two years to 2019–20 and 2020–21.

6.4.2.3 Regulators

AGN stated regulator stations and valves play a critical role in regulating gas pressures and flows.⁹⁴ As we noted in our draft decision, this is the continuation of a program from the current access arrangement period.⁹⁵

We have included the proposed capex of \$11.0 million (\$2014–15, unescalated) for regulators and valves capex in our capex forecast. We consider this is conforming capex under rule 79 of the NGR.⁹⁶ Our final decision, including our reasons, is unchanged from our draft decision.⁹⁷

In its revised proposal, AGN largely accepted the amount we approved in the draft decision for regulators. However, AGN did not agree with our reclassification of the valve corrosion protection project (SA09) to opex in the draft decision. AGN considered

⁹⁰ AGN, *Revised access arrangement information: Attachment 7.1A: Business cases: Addendum to business case SA71*, January 2016, p. 2.

⁹¹ Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016, section 2.2.8.

⁹² For example, there were 31 occasions in 2014 and 2015 when the hourly gas quantities supplied to two of the tariff D customers either reached or exceeded their contracted hourly flows. AGN also submitted it recently received an inquiry from a prospective industrial and commercial customer (AGN, *Revised access arrangement information: Attachment 7.1A: Business cases: Addendum to business case SA71*, January 2016, pp. 4–5)

⁹³ Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016, section 2.2.8.

⁹⁴ AGN, *Access arrangement information for Australian Gas Networks' South Australian Natural Gas distribution network*, July 2015, p. 145.

⁹⁵ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, p. 6-47.

⁹⁶ NGR, rr. 79(2)(c)(i), 79(2)(c) (ii).

⁹⁷ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, pp. 6-45 to 6-48.

the \$0.3 million (\$2014–15) project is a capex item and proposed \$11.3 million (\$2014–15) for regulators capex in the 2016–21 period.⁹⁸

AGN also stated it had classified actual expenditure for this work in the 2011–16 period as capex.⁹⁹ We noted in the draft decision that we included expenditure for this program in our alternative opex estimate in the previous access arrangement review.¹⁰⁰

In response to an information request, AGN again reviewed the classification of this project and agreed with our position in the draft decision to reclassify the project as opex.¹⁰¹ We have therefore assessed this project as opex (see attachment 7). As we discussed in section 6.4.1, we also removed expenditure related to this item in the 2011–16 period from conforming capex.

We note that ECCSA expressed disappointment at the draft decision's relatively minor reduction to regulators capex. ECCSA considers regulators and valves capex to be recurrent expenditure and emphasised the draft decision results in an increase in excess of 100 per cent from their last allowance.¹⁰²

As we detailed in this final decision and in the draft decision, we assessed AGN's capex forecast for regulators and valves against the requirements of the NGR. We consider the amount for this category of \$11.0 million (\$2014–15, unescalated) satisfies those requirements.

6.4.2.4 IT

We accept AGN's revised proposed IT expenditure of \$55.4 million (\$2014–15, unescalated) as we consider it is conforming capex under rule 79. In our draft decision we approved \$37.9 million (\$2014–15, unescalated) of AGN's initial proposal of \$59.7 million.¹⁰³

In its revised proposal, AGN re-proposed two projects, Mobility Integration (\$9 million) and Business Intelligence (\$8.6 million), that it had proposed in its initial proposal. In our draft decision we did not include these projects in our alternative capex estimate. We found that this was not conforming capex under rule 79 because they were discretionary and did not have positive NPVs.¹⁰⁴

⁹⁸ AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, p. 20.

⁹⁹ AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, p. 20.

¹⁰⁰ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, pp. 6-47 to 6-48.

¹⁰¹ AGN, *Response to AER Australian Gas Networks 034 – Valve corrosion protection* [email to AER], 4 February 2016, p. 1.

¹⁰² Energy Consumer's Coalition of SA, *A response to the Australian Energy Regulator draft decision on Australian Gas Networks AA2016 revenue reset*, February 2016, p. 21.

¹⁰³ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, pp. 6-39 to 6-45.

¹⁰⁴ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, pp. 6-43 to 6-44.

In its revised proposal, AGN has submitted addendums to the business cases to justify these projects.¹⁰⁵ These business cases provided further information about the deficiencies in AGN's current systems and cost benefit analyses for the projects over a ten year period.¹⁰⁶ These analyses showed that, over ten years, the NPV for the Mobility Integration project is \$3.3 million and for the Business Intelligence project, it is \$2.4 million.

As part of its revised proposal, AGN submitted a cost benchmarking study conducted by KPMG. AGN submitted that this study showed that its proposed IT expenditure is consistent with good industry practice when compared to other utilities in Australia.¹⁰⁷ KPMG submitted that AGN's IT capex has been below the industry mean in the previous access arrangement period and the early years of the current period.¹⁰⁸ It also argued that after the two investment peaks in 2014–2015 and 2017–19, AGN's IT capex will trend in line with the industry mean for IT capex.¹⁰⁹ AGN argued that the KPMG study indicated that AGN had underinvested in IT in the past and that the proposed IT capex will allow it to fully access the benefits of its current systems and to maintain good industry practice.¹¹⁰

We received three submissions on AGN's proposed IT expenditure from ECCSA, Uniting Care Australia and the CCP.¹¹¹ ECCSA supported our draft decision on IT expenditure and reasserted its position that IT projects should only be approved when they result in a net benefit from opex reduction in less than four years. ECCSA argued that AGN's current IT systems are sufficient and that therefore the repropoed projects are unnecessary.¹¹² Capex will be conforming capex under rule 79 of the NGR if the overall economic value of the expenditure is positive. Uniting Care Australia also supported a reduction in IT capex spending as it did not see the consumer benefit in spending nearly \$60 million on IT.¹¹³

¹⁰⁵ See AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network - January 2016 - Attachment 7.1A Business Cases for operating and capital expenditure PUBLIC*, pp. 61, 89.

¹⁰⁶ AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network, Attachment 7.1A Business Cases for operating and capital expenditure PUBLIC*, January 2016, pp. 66–73, 75, 92–100, and 102.

¹⁰⁷ AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, p. 21.

¹⁰⁸ KPMG, *SA Australian Gas Networks Information Technology cost benchmarking, (Attachment 8.12 to AGN Rev AAI) PUBLIC*, December 2015, p. 15.

¹⁰⁹ KPMG, *SA Australian Gas Networks Information Technology cost benchmarking, (Attachment 8.12 to AGN Rev AAI) PUBLIC*, December 2015, p. 15.

¹¹⁰ AGN, *Revised Access Arrangement Information for AGN's SA Natural Gas Distribution Network, Attachment 8.9 Capital expenditure PUBLIC*, January 2016, p. 23.

¹¹¹ Energy Consumer's Coalition of SA, *A response to the Australian Energy Regulator draft decision on Australian Gas Networks AA2016 revenue reset*, February 2016, pp. 20–21; Uniting Care Australia, *Submission to AER - AGN SA Access Arrangement 2016–21, Draft decision*, March 2016; Consumer Challenge Panel, *Supplementary advice to AER from Consumer Challenge Panel 8 regarding the AER Draft Decision and Australian Gas Networks' (SA) Revised Access Arrangement 2016–21 proposal*, 31 March 2016, p. 4.

¹¹² Energy Consumer's Coalition of SA, *A response to the Australian Energy Regulator draft decision on Australian Gas Networks AA2016 revenue reset*, February 2016, p. 21.

¹¹³ Uniting Care Australia, *Submission to AER - AGN SA Access Arrangement 2016–21, Draft decision*, March 2016, p. 6.

The CCP questioned the need for the two repropoed projects, given the large increase in IT expenditure that is proposed for 2016–21. It suggested that we should consider the deferral of the two projects. The CCP raised concerns regarding the cost allocation for productivity improvements for the field workforce on the basis that these improvements should be funded by APA Group as the managers of the field workforce.¹¹⁴

On the basis of the new information provided by AGN on the necessity of the two projects and their associated NPVs, we are satisfied that the repropoed expenditure is justifiable under rule 79(2)(a). We are also satisfied that this capex would be incurred by a prudent service provider acting efficiently and that it is conforming capex under rule 79. We therefore have included the amounts for these projects in our alternative capex estimate.

6.4.2.5 Growth assets

The driver of growth assets capex is new connections to the network. The capex associated with these connections includes the cost of new mains, gas service pipes from the main to the meter, and the meter itself.

We have included \$85.6 million (\$2014–15, unescalated) of connections net capex in our alternative capex estimate. We consider that this amount is conforming capex under rule 79(1) of the NGR.

AGN's revised proposal included \$114.1 million (\$2014–15, unescalated) for growth assets capex, consisting of:

- \$85.6 million for mains growth capex, large customers and both inlets and meters growth assets capex.
- \$28.5 million for capex in new growth areas, consisting of the Two Wells and Mount Barker projects:
 - Two Wells - AGN's initial proposal included capex of \$5.0 million to extend its high pressure network by nine kilometres to the Two Wells township north of Adelaide.¹¹⁵ In the draft decision we were not satisfied that the proposed capex was conforming capex because it was not justified under rule 79(2)(b) of the NGR.¹¹⁶ AGN has repropoed the Two Wells project on the basis that it is justified under rule 79(2)(b) of the NGR because it yields a positive NPV.

¹¹⁷

¹¹⁴ Consumer Challenge Panel, *Supplementary advice to AER from Consumer Challenge Panel 8 regarding the AER Draft Decision and Australian Gas Networks' (SA) Revised Access Arrangement 2016–21 proposal*, 31 March 2016, p. 4.

¹¹⁵ AGN, *Revised Access Arrangement Information, Attachment 7.1A, Business Cases for Operational Expenditure and Capital Expenditure*, January 2016, p.109.

¹¹⁶ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, pp.6-6 to 6-24.

¹¹⁷ AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, p. 25.

- Mount Barker - AGN's initial proposal included a 'significant extension event' as a cost pass through to supply gas to the area of Mount Barker, a township south east of Adelaide.¹¹⁸ In the draft decision we were not satisfied that costs relating to significant extensions could be characterised as a pass through event.¹¹⁹ In response, AGN included \$23.5 million (\$2014–15, unescalated) capex to expand its network by 36 kilometres to Mount Barker.

AGN's revised proposal accepted our positions in the draft decision on mains growth, large customers, and both inlets and meters growth assets capex. However, our position in this final decision is that we do not accept AGN's re-proposed new growth area capex as set out in its revised proposal.

AGN submitted that the capex for the Two Wells and Mount Barker extension projects is conforming capex justified under rule 79(2)(b) of the NGR. Rule 79(2)(b) states the capex is conforming if the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capex (NPV analysis).

We are not satisfied that this capex is conforming capex on the basis that it is likely that the expected incremental revenue will not exceed the present value of the capex.¹²⁰ In determining the incremental revenue, AGN has relied on a forecast penetration rate of 95 per cent for both the Two Wells and Mount Barker extensions. AGN's proposed penetration rate is based on data from the Sunday Estate development, Aldinga. We are not satisfied that this penetration rate is the best forecast or estimate possible. This is because we consider that the penetration rate is likely to be lower than the 95 per cent penetration rate that AGN used in its NPV analysis for these extension projects for the following reasons:¹²¹

- The Sunday Estate data is outdated and unlikely to reflect current trends in the demand for gas connections. This estate was commissioned in a number of stages over a six-year period from 2005 to 2010. AGN submitted that the penetration rate achieved in this estate is a reasonable proxy because it is a similar new residential development on Adelaide's suburban fringe and represents the most recent example of such development with audited penetration data.¹²² However, we note that there has been a significant reduction in the network wide penetration rate

¹¹⁸ AGN, *Access Arrangement Information for Australian Gas Networks' South Australian Gas Distribution Network*, July 2015, p. 266.

¹¹⁹ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 11: Reference tariff variation mechanism*, November 2015, pp.11-11 to 11-37.

¹²⁰ NGR, r. 79(1)

¹²¹ NGR, r. 74(2)(b)

¹²² AGN, *Response to Information Request AER Australian Gas Networks 029* [email to AER], received 4 February 2016.

from 2011 onwards¹²³ that is not properly captured in the Sunday Estate penetration rate.

- Further, the reduced competitiveness of gas relative to electricity—the driver of the downwards trend of network wide connections¹²⁴—remains a relevant influence on the penetration rates for the Two Wells and Mount Barker extensions. The network average penetration rate for new dwellings is the best estimate in the circumstances because on the information available, it best reflects current trends in gas connections.
- AGN's proposed penetration rate is based on a single small sample of one suburb with 705 dwellings.¹²⁵ We consider this sample size is too small from which reliable inferences can be drawn.¹²⁶
- The reasons that AGN provided in support of the penetration rate for new growth areas likely being materially higher than its network average penetration rate for new dwellings in established areas are not compelling. Those reasons are:
 - customers are not disrupted by installation works before houses are built
 - there are general benefits of gas as a cleaner, more reliable, less intrusive energy source
 - the new South Australian residential water heater installation requirements will encourage greater take up of gas connection as it is the least cost compliant option and is favoured by customers and developers.¹²⁷

The latter two reasons apply to any new dwelling connection on the network and do not justify a conclusion that a materially higher penetration rate for the new growth area connecting prior to a house being built.

We discuss the aspects of the NPV assessment below, including the penetration rate and period of analysis, and other considerations raised by stakeholders in response to the draft decision and AGN's revised proposal.

¹²³ Core Energy Group, *Gas demand forecasts - Australian Gas Networks: SA Gas Access Arrangement 2017-21* (Attachment 14.1 to AGN's initial proposal), July 2015, p. 30.

¹²⁴ Core Energy Group, *Gas demand forecasts - Australian Gas Networks: SA Gas Access Arrangement 2017-21* (Attachment 14.1 to AGN's initial proposal), July 2015, p. 19.

¹²⁵ In response to further requests by the AER, AGN did provide further suburb examples of residential developments with high penetration rates similar to Sunday Estate. However, this data was unaudited and based on information provided by developers and/or drive-by surveys and therefore not a robust basis for comparison, see AGN Response to Information Request AER Australian Gas Networks 46, p. 2.

¹²⁶ According to AGN's website, as at 30 June 2014 it has 423,462 customers. This sample represents less than 1 per cent of total customers, see: <http://www.australiangasnetworks.com.au/our-business/operational-structure/gas-networks-information-and-statistics/>.

¹²⁷ AGN, *Response to Information Request, AER Australian Gas Networks 029* [email to AER], received 4 February 2016, pp.12-13.

NPV analysis

When assessing AGN's revised proposal, we considered the historical trend of the proportion of new dwellings forecast to connect to AGN's network in the next access arrangement period. AGN's consultant, Core Energy, demonstrated a decline in network wide penetration rates for new dwellings from 98 per cent in 2011 to 73 per cent in 2014. Further, AGN forecast penetration rates to continue to decline to 65 per cent by 2021. We accepted AGN's forecast new dwelling connections in the draft decision.¹²⁸

For the reasons outlined above, we are not satisfied that AGN has demonstrated that the average level of penetration experienced in the Sunday Estate reflects or is a reasonable proxy for the best estimate of the penetration rate that the Two Wells and Mount Barker projects is likely to experience during the next period. It is our view that the forecast network penetration rate of 65 per cent for new estates represents the best forecast in the circumstances because it better reflects current trends in gas connections.

Using a penetration rate of 65 per cent in the NPV analysis and holding each of AGN's other assumptions constant result in both extension projects yielding a negative NPV.¹²⁹ This means that the present value of the expected incremental revenue to be generated from these projects does not exceed the present value of the capex and are not justifiable under rule 79(2)(b) of the NGR.

AGN submitted that standard practice for evaluating residential growth investments is to assess them against 20 years of revenue. AGN noted that this is explicit in the Distribution System Code of Victoria and is consistent with good industry practice (and applied by AGN across all of its networks) is effective for evaluating single point connections where AGN only incurs capital costs to connect customers in Year 1 of the project.¹³⁰ Over a 20 year analysis period, holding each of AGN's assumptions constant, neither extension project yields a positive NPV.

AGN submitted that for major residential extensions it models a 20 year build-out term with revenue assessed over 30 years. AGN has assessed revenue for these extension projects over 30 years because it considers that truncating revenue at Year 20 does not provide a fair and reasonable representation of the economic viability of domestic connections expected to occur the latter years of the project (i.e. in years 15-20).¹³¹

¹²⁸ Core Energy Group, *Gas demand forecasts - Australian Gas Networks: SA Gas Access Arrangement 2017-21* (Attachment 14.1 to AGN's initial proposal), July 2015, p. 97; AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 13: Demand*, November 2015, pp. 13-6 to 13-7.

¹²⁹ Holding all AGN's assumptions equal, a penetration rate greater than approximately 87 per cent for Mt Barker and 79 per cent for Two Wells would be required to produce a positive NPV for these projects.

¹³⁰ AGN, *Email from Ben Wilson to Sebastian Roberts, AGN Mount Barker and CESS* [email to AER], 24 March 2016.

¹³¹ See: AGN, *Revised Access Arrangement Information, Attachment 7.1A, Business Cases for Operational Expenditure and Capital Expenditure*, January 2016 p.20; AGN, *Email from Ben Wilson to Sebastian Roberts, AGN Mount Barker and CESS* [email to AER], 24 March 2016.

We sought advice from Zincara on the appropriate period of analysis for these projects. Zincara observed that, from its experience, businesses and governments have used 20 years in various gas studies and development of regional infrastructure.¹³² Zincara also highlighted that the Victoria Gas Distribution System Code requires a 20 year period of analysis, as did AGN.¹³³ Zincara also noted that there is significant instability in the nature of the gas market (specifically, gas prices and future gas availability) and uncertainty about the effect of technological changes on the future demand for gas.¹³⁴ Zincara concludes that a 20 year period is a reasonable estimate for analysis.

We consider that AGN's approach to calculate the NPV over a period of 30 years is generous in light of the uncertainties about the gas market and the effect of technological changes on the future demand for gas as highlighted by Zincara and the benchmark 20 year period applied by the Victoria Gas Distribution System Code. However, in this instance we are satisfied that AGN's reasons for extending the assessment of revenue for connections by a further 10 years to ensure fair consideration of those late term connections is justified.

A not insignificant portion of total connections are forecast by AGN to occur in those outer years (23 per cent and 27 per cent of total connections are forecast to occur by AGN in the final 5 years of the Two Wells and Mt Barker extensions respectively¹³⁵) which, under a 20 year period of analysis, would otherwise not be considered in the NPV analysis. Excluding the revenue derived from these connections beyond year 20 may unreasonably understate the incremental revenue to be generated by the extension. However, as noted above, using the penetration rate of 65 per cent in the NPV analysis and holding each of AGN's assumptions constant, including the modelling period of 30 years, result in both extension projects being NPV negative.

Other considerations

The Government of South Australia noted in its submission that it was important that we assess whether the Mount Barker extension can be completed within the next access arrangement period or whether the capex should be spread across the following access arrangement period.¹³⁶ The CCP also asked us to review the timing of

¹³² Zincara Pty Ltd has been providing strategic advice to the energy industry, government and energy regulators on energy infrastructure for over 10 years. In particular, Zincara has carried out a number of reviews on the reasonableness of the capital and operating expenditure for energy infrastructure as part of the Access Arrangement regime in Australia.

¹³³ Zincara, Advice on period of analysis, 24 March 2016.

¹³⁴ When determining what it viewed to be an appropriate time period Zincara considered a number of factors, including the future cost of gas, changes in technology, future source of energy and availability of future gas supply.

¹³⁵ AGN, *Revised Access Arrangement Information, SA24, Supporting information 1, cashflow model (Two Wells)* CONFIDENTIAL, January 2016; AGN, *Revised proposal, SA25, Supporting information 2, cashflow model (Mount Barker)* CONFIDENTIAL, January 2016.

¹³⁶ South Australian Government, *Submission on Australian Gas Networks, Access Arrangement 2016–21, Draft Decision*, 24 February 2016, p. 2.

the project and the extent to which expenditure may be required in the 2016-21 period.¹³⁷

We have also considered and sought advice from Zincara on AGN's ability to deliver these extension projects in light of its other capex programs, including its significant mains replacement program. Zincara explained that contractors carrying out mains replacement activities are not involved in these types of extension projects and any shortage of contractors in SA to carry out the extensions could be backfilled from interstate. Zincara observed that from an operational perspective, it believes that the mains replacement program is unlikely to delay the two mains extension programs.¹³⁸ But nonetheless we are rejecting these projects for the reasons outlined above.

The CCP also asked us to consider the option of requiring capital contributions from developers to offset the cost imposed on existing customers.¹³⁹ AGN's revised proposal did not include any provision for capital contributions. We asked AGN if it had considered the option of capital contributions.¹⁴⁰ AGN responded that capital contributions were not required on the basis that the extension projects were NPV positive.¹⁴¹

6.4.2.6 Other distribution system

This category captures distribution system capex that do not fall into the categories we discussed above. AGN provided the justification for other distribution system capex, including the assessment against NGR requirements and its stakeholder program, in the business case for each project.¹⁴²

We accept AGN's revised proposed expenditure of \$21.3 million (\$2014–15, unescalated) for other distribution system capex. We consider this is conforming capex under rule 79 of the NGR. Our draft decision included \$10.0 million (\$2014–15, unescalated) of other distribution system capex in our alternative capex estimate.¹⁴³

AGN initially proposed \$37.0 million for this capex category. In its revised proposal it re-proposed capex for three projects, where the revised capex amounts are lower than its initial proposal. These projects are:

¹³⁷ Consumer Challenge Panel, *Supplementary advice to AER from Consumer Challenge Panel 8 regarding the AER Draft Decision and Australian Gas Networks' (SA) Revised Access Arrangement 2016–21 proposal*, 31 March 2016, p. 3.

¹³⁸ Zincara, Advice on deliverability of new growth areas capex, 21 March 2016.

¹³⁹ Consumer Challenge Panel, *Supplementary advice to AER from Consumer Challenge Panel 8 regarding the AER Draft Decision and Australian Gas Networks' (SA) Revised Access Arrangement 2016–21 proposal*, 31 March 2016, p. 3.

¹⁴⁰ AER, *Information Request AER Australian Gas Networks 046* [email to AGN], 3 March 2016.

¹⁴¹ AGN, *Response to Information Request, AER Australian Gas Networks 046* [email to AER], 11 March 2016, p. 5.

¹⁴² AGN, *Access arrangement information for Australian Gas Networks' South Australian Natural Gas distribution network*, July 2015, p. 147; AGN, *Access arrangement information: Attachment 7.1: Business cases*, July 2015; AGN, *Revised access arrangement information: Attachment 7.1A: Business cases*, January 2016.

¹⁴³ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, p. 6-48.

- HDPE camera investigation and repair program (SA52);
- Fire safety valves project (SA31); and
- Sleeved railway crossing (SA10).

Our reasons for accepting the capex associated with HDPE camera investigation and repair program is discussed in 6.4.2.1. We discuss our assessment of capex associated with the other two projects below.

Fire safety valves (SA31)

We are satisfied AGN's proposed capex in its revised proposal of \$1.2 million (\$2014–15, unescalated) for the fire safety valves project (SA31) is conforming capex under rule 79.¹⁴⁴ This comprises:

- \$1.2 million (\$2014–15, unescalated) to install fire safety valves in high bushfire risk areas.
- \$84,000 (\$2014–15, unescalated) to install fire safety valves in sites where the meter is located adjacent to a brush fence.

In its initial proposal, AGN proposed \$10.5 million (\$2014–15, unescalated) for the project. The capex proposed involved continuing the current program of installing fire safety valves in bushfire risk areas. AGN also proposed to expand the program to install the valves in other areas (non-bush fire prone areas). Our draft decision approved \$520,000 (\$2014–15, unescalated) as conforming capex for this project. The reductions were due to:¹⁴⁵

- reducing the volumes forecast for installations in bushfire risk areas to 1,000 installations per annum, reflecting the annual rate AGN achieved in recent years;
- removal of expenditure amounts for installations in properties where gas meters are in proximity to brush fences; and
- removal of expenditure amounts for installations in all new and changeover domestic meter installations.

In the revised proposal, AGN noted it commenced installing fire safety valves in bushfire risk areas in 2013–14 and installed 3747 valves in 2013–14 and 2014–15. This equates to approximately 1900 installations per annum.¹⁴⁶ AGN stated it recalculated the number of sites in bushfire risk areas that require installations to be 10920 (1020 more than anticipated in the initial proposal). AGN therefore proposed to install 2185 sites per annum in the 2016–21 period, noting this is below the 2294

¹⁴⁴ NGR, rr. 79(2)(c)(i), (ii).

¹⁴⁵ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, pp. 6-49 to 6-50.

¹⁴⁶ AGN, *Revised access arrangement information: Attachment 7.1A: Business cases: Addendum to business case SA31*, January 2016, pp. 3–4.

installations it achieved in 2013–14.¹⁴⁷ AGN's revised proposal included \$1.2 million (\$2014–15, unescalated) to install fire safety valves in bushfire risk areas for the 2016–21 period.¹⁴⁸

Sleeman Consulting noted AGN did not explain why the rate of installation of fire safety valves progressively declined from 2013–14 to 2015–16 (which is an estimated year). However, Sleeman Consulting accepted it is prudent for AGN to expedite the installation of fire safety valves in bush fire prone areas. Further, AGN has demonstrated the capability to complete around 2300 installations per annum.¹⁴⁹ Having regard to Sleeman Consulting's advice, we have included \$1.2 million (\$2014–15, unescalated) for the installation of fire safety valves in bushfire prone areas in conforming capex for the 2016–21 period.

In response to the draft decision, AGN clarified that fire safety valves at brush fence sites are not intended to address the risk of damage to the gas meter. Rather, it is intended to address the risk that the fire will escalate if the gas meter or connection fittings fail as a result of a brush fence fire. Further, AGN stated there is no isolation valve between the gas main in the street and the gas meter at the property. Hence, isolating the service during a fire is impractical due to the need for excavation.¹⁵⁰ AGN's revised proposal included \$84 000 (\$2014–15, unescalated) to install fire safety valves in brush fence locations for the 2016–21 period.¹⁵¹

In the advice to our draft decision, Sleeman Consulting considered the risk of a brush fence fire causing damage to be very low, since a convergence of factors needed to exist. Specifically, the brush fence needed to be close to meter and the brush fence needed to catch fire. Given the information in the revised proposal, Sleeman Consulting accepts AGN's view that, in the event these factors do converge, it is prudent to avoid the risk that the fire may escalate.¹⁵² Having regard to Sleeman Consulting's advice we have included \$84 000 (\$2014–15, unescalated) for the installation of fire safety valves in brush fence locations in conforming capex for the 2016–21 period.

Sleeved railway crossings (SA10)

¹⁴⁷ AGN, *Revised access arrangement information: Attachment 7.1A: Business cases: Addendum to business case SA31*, January 2016, p. 4.

¹⁴⁸ AGN, *Revised access arrangement information: Attachment 7.1A: Business cases: Addendum to business case SA31*, January 2016, p. 6.

¹⁴⁹ Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016, sections 3.1.4–3.1.6.

¹⁵⁰ AGN, *Revised access arrangement information: Attachment 7.1A: Business cases: Addendum to business case SA31*, January 2016, p. 5.

¹⁵¹ AGN, *Revised access arrangement information: Attachment 7.1A: Business cases: Addendum to business case SA31*, January 2016, p. 6.

¹⁵² Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016, sections 3.1.3.

We are satisfied the revised proposal's forecast expenditure of \$1.6 million (\$2014–15, unescalated) for the sleeved railway crossings project (SA10) is conforming capex under rule 79.¹⁵³

AGN initially proposed \$2.2 million (\$2014–15, unescalated) for the project. Our draft decision included \$1.0 million (\$2014–15, unescalated) as conforming capex for this project to reflect the annual rate AGN achieved with the same type of works in the 2011–16 period.¹⁵⁴

We and Sleeman Consulting originally understood AGN completed work at 25 sites over a five year period. Hence, we applied a volume of five inspections and repairs per annum in the draft decision.¹⁵⁵ In the revised proposal, AGN clarified that it completed the 25 inspections/repairs over the three years from 2012–13 to 2014–15, which equates to an average of eight sites per annum.¹⁵⁶

Given this clarification, we agree with Sleeman Consulting that an ongoing rate of eight inspections/repairs per annum is achievable, reasonable and prudent.¹⁵⁷ Our final decision amount of \$1.6 million (\$2014–15, unescalated) for this project reflects this higher number of annual inspections/repairs per annum.

6.4.2.7 Escalation

In our draft decision, we accepted AGN's labour cost escalation methodology but used updated figures.

In this final decision, we accept AGN's revised methodology and application of labour cost escalation to new estates. In our draft decision, we did not accept that labour escalation should be applied to new estate connections, in the same way it has to other capex categories. In our draft decision, we revised AGN's capex forecast to reflect actual contract provision, where the provision net-off the CPI from the previous year against CPI in the current year and then multiply the result by a factor of 0.85. This escalation was applied to the end of the 2016-21 access arrangement period.

In its revised proposal, AGN notes that the new contracts expire either 31 December 2017 or 30 June 2018. AGN has therefore modified the approach we applied in the

¹⁵³ NGR, rr. 79(2)(c)(i), (ii).

¹⁵⁴ AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, pp. 6-51 to 6-52.

¹⁵⁵ Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016, sections 3.2.2; AER, *Draft decision, Australian Gas Networks 2016 to 2021, Attachment 6: Capital expenditure*, November 2015, pp. 6-51 to 6-52.

¹⁵⁶ AGN, *Revised access arrangement information: Attachment 7.1A: Business cases: Addendum to business case SA10*, January 2016, pp. 2–3.

¹⁵⁷ Sleeman Consulting, *Comments on Australian Gas Networks' response to the AER's draft decision*, 28 March 2016, sections 3.2.3.

draft decision to reflect the expiry date of the contracts and, from 1 July 2018, has applied the same escalation as has been applied for the other capex categories.¹⁵⁸

¹⁵⁸ AGN, *Revised access arrangement information: Attachment 8.9: Capital expenditure*, January 2016, p. 33.

Appendix A Confidential appendix

Appendix B Areas of concern with AGN's proposal on mains replacement

In this section, we address the concerns we have identified with AGN's proposal, being:

1. AGN's requirements to comply with the applicable technical standards;
2. AGN's risk ranking and associated risk treatment of its main pipes;
3. An error with the underlying risk framework used to prioritise its mains pipes; and
4. Relevance of a robust analysis of the costs and benefits of its proposal.

These concerns are discussed below.

AGN's requirements to comply with the applicable technical standards

Technical standard AS/NZS 4645.1:2008 is the engineering standard that applies to the management of gas distribution networks in Australia. This standard prescribes a risk management approach in accordance with AS/NZS 4360 (Risk Management). However risk management standard AS/NZS 4360 was superseded by AS/NZS ISO 31000 in 2009.¹⁵⁹

Our concerns here relate to whether, or the extent to which, AGN has applied the applicable technical standards (in particular ISO 31000) for risk assessment purposes, and the weight it has placed on its risk assessment based on Appendix C of AS/NZS 4645, which is an 'informative appendix'.

AGN submits that it has an obligation under regulation 37 of the Gas Regulations 2012 to comply with AS/NZS 4645 by eliminating risk associated with its main pipes or to reduce risk to 'low' or ALARP.¹⁶⁰ In particular, its risk assessment is based on Appendix C of that standard. Paragraph 2.3.4 of AS/NZS 4645 states:

Risk assessment of threats shall be undertaken in accordance with AS/NZS 4360. Appendix C provides the requirements for qualitative risk assessment and it provides a risk matrix that should be used in an AS/NZS 4360 qualitative risk assessment.

¹⁵⁹ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 37.

¹⁶⁰ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 2.

However, regulation 37 requires AGN to comply with any applicable requirements of AS/NZS 4645 and Appendix C is an 'informative' appendix to be used only for information and guidance.¹⁶¹

As noted above, AS/NZS ISO 31000 superseded AS/NZS 4360. AGN recognise this, and submits that it is required to comply with a mix of the two standards:¹⁶²

The two standards (AS 4645.1: 2008 and AS/NZS ISO 31000: 2009) accordingly operate together in the following way in respect of gas distribution networks:

certain quantitative assessments are prescribed in AS/NZS ISO 31000: 2009 itself;

qualitative risk assessments for gas distribution networks are as prescribed by AS 4645.1: 2008 (per paragraph 2.3.4 of that Standard).

Whilst we recognise there may be some ambiguity, in our view references to the superseded AS/NZS 4360 in AS/NZS 4645 ought to be read as references to the current AS/NZS ISO 31000, which in turn should be used for risk assessments. We raised this with AGN who in response reiterated its view that AS 4645 and AS 4360 should apply when undertaking a risk assessment of its main pipes.¹⁶³

On balance, we do not agree with AGN's position. The undertaking of risk assessments on the basis of the superseded AS/NZS 4645, or on a combination of that and AS/NZS ISO 31000, raises a question about whether its risk assessments can be said to be best practice or the kinds of risk assessments a prudent operator would undertake acting efficiently.

AGN's risk ranking and associated risk treatment of its main pipes

Notwithstanding our concerns that AGN may have applied the incorrect standard to assess the risk of its main pipes, we consider that its risk assessment against Appendix C of the AS/NZS 4645 overstates the risk associated with its main pipes.

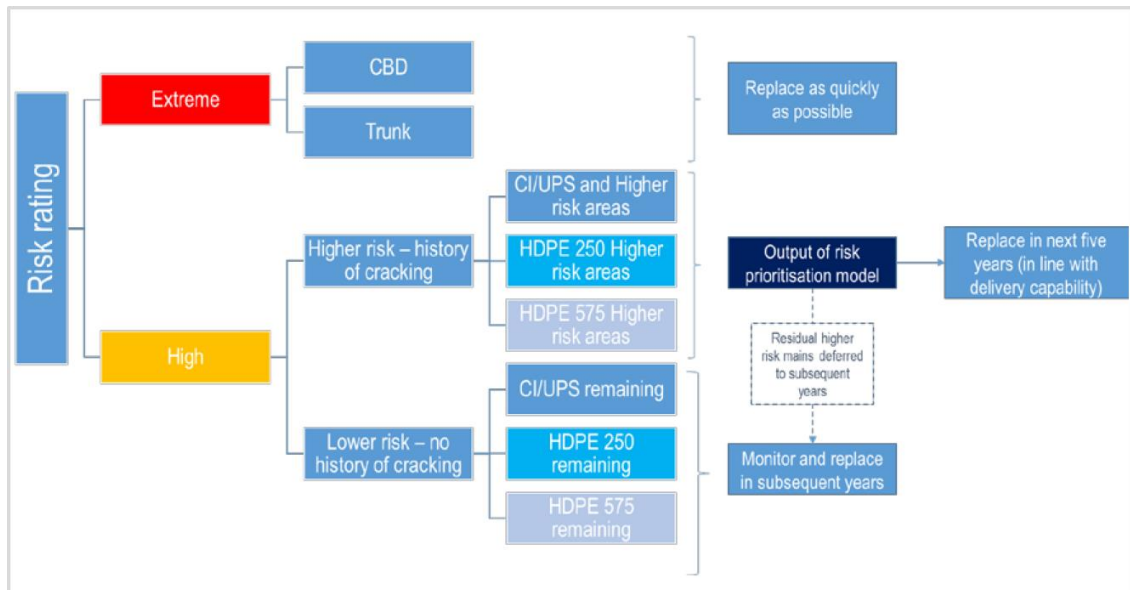
Figure 6.2 summarises AGN's risk assessment and risk prioritisation process.

¹⁶¹ AS/NZS 4645 state that "The terms 'normative' and 'informative' have been used in this Standard to define the application of the appendix to which they apply. A 'normative' appendix is an integral part of a Standard, whereas an 'informative' appendix is only for information and guidance." p. 3.

¹⁶² AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 37.

¹⁶³ AGN, *Response to draft decision: mains replacement program - Further submissions by AGN on "cost-benefit analysis" issue* [email to AER], 29 February 2016, p. 19.

Figure 6.2 Summary of AGN’s risk assessment and risk prioritisation process



Source: AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 30.

To rank the main pipes according to risk, AGN has grouped its network mains into 11 categories based on asset material, location and pressure.¹⁶⁴ It then identifies the consequence¹⁶⁵ (severity) and likelihood¹⁶⁶ (frequency) of that event occurring. Combining these produces the level of risk assessed (or overall risk ranking). The risk ratings range from (in order of high risk to low risk), ‘extreme’, ‘high’, ‘intermediate’, ‘low’ and ‘negligible’. These risk rating have a corresponding recommended risk treatment as set out in Appendix C AS/NZS 4645. For instance, for those main pipes ranked as ‘extreme’, ‘...the risk must be reduced immediately’. For those mains ranked as ‘high’, ‘...the risk must be reduced as soon as possible, typically within a timescale of not more than a few weeks.’¹⁶⁷

¹⁶⁴ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 17.

¹⁶⁵ The AS/NZS 4645 framework ranks the severity of the failure event from ‘catastrophic’(multiple fatalities) to ‘trivial’ (minimal impact on health and safety) on people, supply and the environment (AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, pp. 18–19)

¹⁶⁶ The AS/NZ4645 framework has 5 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). (AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 21).

¹⁶⁷ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 26.

AGN submits that its risk assessment identifies 2619 kilometres of ‘at risk’ mains (those rated as having ‘extreme’ and ‘high’ network risk) that must be addressed.¹⁶⁸

We consider that AGN has overstated the risk of its main pipes because:

1. In its risk assessment (risk ranking of its main pipes), AGN ignores the effect that risk mitigation strategies¹⁶⁹ that it currently has in place and proposes to implement, have on reducing the overall risk associated with main pipes.¹⁷⁰ Such an approach will overstate the risk associated with main pipes to be replaced in the next access arrangement period, and understates the value of risk mitigation strategies in managing risk over the current access arrangement period. We note that in its revised proposal AGN discusses risk mitigation strategies.¹⁷¹ While AGN clearly recognises that risk mitigation strategies are required to comply with its safety obligations over the current access arrangement period, its risk assessment does not take into account the effect of these strategies over the next access arrangement period.
2. AGN’s risk rating of its main pipes does not align with the required risk treatment for high risk main pipes, which suggests that these main pipes should be ranked at a lower risk. We observe that:
 - AGN’s risk rating for ‘at risk’ main pipes is based on nine years of crack history. However, this is at odds with the recommended risk treatment that corresponds with that risk rating as set out in Appendix C of AS/NZS 4645. For instance, for those main pipes ranked as ‘extreme’, ‘...the risk must be reduced immediately’ and for those ranked as ‘high’, ‘...the risk must be reduced as soon as possible, typically within a timescale of not more than a few weeks.’¹⁷² So despite identifying these mains as ‘extreme’ and ‘high’, it has not replaced them.
 - AGN submits that the remaining 1354 kilometres of ‘at risk’ mains it intends to replace in subsequent access arrangement periods will be carefully monitored over the next access arrangement period. Again, this is at odds with the required risk treatment for those main pipes ranked as ‘extreme’ and ‘high’ risk.

¹⁶⁸ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 2.

¹⁶⁹ For example: installing ground vents, pressure reduction where there is a history of cracks

¹⁷⁰ AGN specifically notes in its proposal that no mitigation strategies are considered in its risk assessment (see, for example, pp. 21, 23 of attachment 8.10).

¹⁷¹ For instance, AGN submits that it has had to develop several risk mitigation strategies for main pipes ranked as ‘extreme’ and ‘high’. In particular, it states that “The current mains replacement program and various risk mitigation activities have been underway since 2011 and are working towards lowering the overall network risk.” See AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 27.

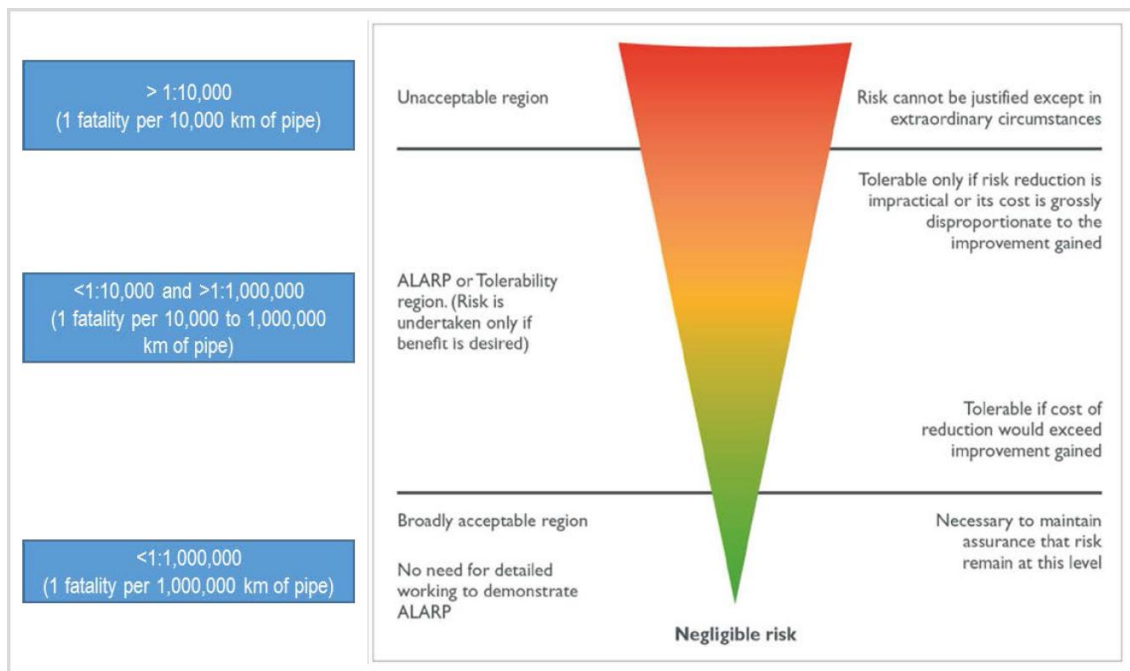
¹⁷² AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 26.

An error with the underlying risk framework used to prioritise its mains pipes

AGN explained that its risk prioritisation model adopts an approach to risk tolerance that is based on the principles used by the UK's Health & Safety Executive (HSE) and Ofgem¹⁷³.¹⁷⁴ AGN used the HSE's 'tolerability of risk' framework to provide guidance on various asset class risks,¹⁷⁵ however it has misinterpreted the risk thresholds outlined by the HSE and has therefore incorrectly classified the risk levels of its mains.

Figure 6.3 illustrates the tolerability of risk thresholds, as set out in AGN's revised proposal.

Figure 6.3 Tolerability of risk framework



Source: AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 31.

Cambridge Economic Policy Associates (CEPA) were engaged by the HSE and Ofgem in 2011 to undertake the 10 year review of the Iron Mains Replacement Programme in the UK.¹⁷⁶ In the UK, HSE and Ofgem used historical data on pipe cracking and other characteristics to rank the risks associated with CI/UPS and HDPE mains. Through their tolerability of risk framework, they identified thresholds for the risk of fatality,

¹⁷³ Office of Gas and Electricity Markets, the energy network regulator in the UK.

¹⁷⁴ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 30.

¹⁷⁵ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 30.

¹⁷⁶ Cambridge Economic Policy Associates Ltd, *HSE/Ofgem: 10 year review of the Iron Mains Replacement Programme*, 2011, p. 27.

which was intended to assist gas businesses make judgements about whether the risks are tolerable.¹⁷⁷

AGN's application of this method considers the crack history of CI/UPS and HDPE mains for each suburb over nine years of recent history. This crack history, combined with the length of mains (by suburb and by type) and the known incident history, is used to derive the overall expected annual value of statistical fatalities of mains by mains type. The expected annual value of fatalities per kilometre is then compared to risk thresholds in the risk tolerability framework to assess where each mains type appears on this scale. Hence the overall expected annual value of fatalities per kilometre of mains forms the fundamental basis of AGN mains risk assessment and determines the length of mains to be replaced.

There are two key thresholds in the framework: the 'unacceptable' risk boundary (upper boundary in Figure 6.3) and the 'broadly acceptable' risk boundary (lower boundary in Figure 6.3). The area between these boundaries is called the 'ALARP or tolerability region'. As can be seen in Figure 6.3, in AGN's analysis these thresholds have been respectively assigned values of '1 fatality in 10,000 kilometres of mains per annum' (unacceptable boundary) and '1 fatality per 1,000,000 kilometres of mains per annum' (broadly acceptable boundary). Thus, a main pipe with an expected value of fatalities per kilometre of more than 1 fatality per 10,000 kilometres of main pipe would be deemed under AGN's tolerability of risk framework as having risk at an 'unacceptable level' and therefore would be prioritised in the model.

However, we note that the thresholds as described in CEPA's review of HSE/Ofgem's program do not specify that the ratios for each boundary is based on fatalities per kilometre.¹⁷⁸ Fatalities per kilometre is the unit of measure used by AGN in its framework. We confirmed with CEPA that the ratio used in the HSE/Ofgem review is fatalities per number of people exposed (i.e. the exposed population).¹⁷⁹

Our analysis indicated that applying the ratio of fatalities per number of people (versus kilometres, as AGN has) significantly changes the risk thresholds. We converted the thresholds from fatalities per number of people to per kilometre by accounting for population density, dividing the population of South Australia by the total kilometres of AGN's mains. The outcome is that our alternative risk threshold for intolerable risk (1 fatality per 10,000 people per year) is 1 fatality per 46.8 kilometres of mains per year. At this threshold, none of the suburbs contain mains that exhibit an intolerable level of risk. In our view the result of reweighting mains risk at corrected thresholds, in addition to our other findings (see above), indicates that AGN has overstated the risk of its mains.

¹⁷⁷ Cambridge Economic Policy Associates Ltd, *HSE/Ofgem: 10 year review of the Iron Mains Replacement Programme*, 2011, p. 27.

¹⁷⁸ Cambridge Economic Policy Associates Ltd, *HSE/Ofgem: 10 year review of the Iron Mains Replacement Programme*, 2011, p. 27.

¹⁷⁹ AER email exchange with CEPA, 12 February 2016.

The relevance of a robust analysis of the costs and benefits of its proposal

In its revised proposal, AGN submitted that AS/NZS ISO 31000 requires it to undertake a certain level of quantitative assessment but not a full cost-benefit analysis (CBA).¹⁸⁰ AGN also submitted that the standard merely requires that certain costings and other assessments be made as part of assessing risk treatment options.

In its letter of 1 March 2016, AGN reiterated that:¹⁸¹

- CBA is only required if a business is not operating in accordance with AS/NZS 4645 by reducing the risk to low;
- Neither the National Gas Rules or the relevant standards require a CBA to inform the required volume of mains replacement;
- CBA is imprecise and cannot be relied upon to inform a decision on the prudent volume of mains replacement;
- ISO 31000 does not change the require risk assessment and expressly states decision should not be based on economic grounds.

It provides two reports to support this argument.

The HoustonKemp report concludes that in a case where expenditure must be undertaken to meet statutory obligations (in this case safety) the required analysis is not a CBA but rather the test is which option discharges the relevant obligation at the lowest net cost, taking into account variations in costs and benefits between options.¹⁸²

The GPA Engineering report concludes that a CBA is not required where a distributor is taking the required actions under AS 4645 to reduce risk from extreme or high to low/negligible.¹⁸³

We do not agree with AGN's contention that safety related expenditure should not be considered within a CBA framework because:

- we are required to consider the efficiency (and prudence) of proposed capex under rule 79(1)(a) of the NGR. Analysing the costs and benefits of a proposal is often crucial to assessing the efficiency of a capex program. A CBA or other quantitative risk assessment is therefore instructive for our assessment purposes.
- where a business largely relies on a qualitative assessment in support of its proposed capex, the inevitable subjectivity inherent in such an assessment gives

¹⁸⁰ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 37.

¹⁸¹ AGN, *Mains Replacement Program Alternate Proposal to AER*, 1 March 2016, p. 1.

¹⁸² HoustonKemp, *Cost-benefit analysis in the context of meeting safety standards, Executive summary*, February 2016..

¹⁸³ GPA Engineering, *Application of cost benefit analysis for ALARP Assessment: AGN SA networks mains replacement program*, February 2016, p. i.

rise to the real possibility that risks have been overstated. Conversely, quantifying the costs and benefits allows for a more objective assessment of the level of risks by accounting for the probability and the impact of harm occurring and the cost to mitigate those risks. AGN's risk prioritisation model,¹⁸⁴ which is based on the HSE's 'tolerability of risk' framework,¹⁸⁵ provides a good foundation to undertake a CBA, notwithstanding issues discussed earlier. We note that CEPA undertook a CBA in its 10 year review of the HSE/Ofgem iron mains replacement program.¹⁸⁶

- Whilst we recognise AGN and HoustonKemp's concerns that a CBA is imprecise,¹⁸⁷ in our view this does not detract from the importance of a CBA, in addition to other material we would have regard to, in assessing the efficiency of a proposed capex program.
- Guidance is provided in clause 8, sub-division 2 of the Work Health and Safety Act 2012 (SA) which sets out a CBA framework for a business to demonstrate that the cost associated with eliminating or minimising risk is not grossly disproportionate to the risk. As referenced by AGN:¹⁸⁸

reasonably practicable, in relation to a duty to ensure health and safety, means that which is, or was at a particular time, reasonably able to be done in relation to ensuring health and safety, taking into account and weighing up all relevant matters including—

...

(e) after assessing the extent of the risk and the available ways of eliminating or minimising the risk, the cost associated with available ways of eliminating or minimising the risk, including whether the cost is grossly disproportionate to the risk.

AGN explained that cost is only a basis for not addressing a risk where the cost is grossly disproportionate to the risk.¹⁸⁹ We agree with AGN's assessment, but note that in order to determine whether a cost is grossly disproportionate, it must first quantify the costs and the extent of the risk reduction achieved (i.e. the benefit). AGN may then conclude the cost is not grossly disproportionate, thereby justifying the risk mitigation measure.

¹⁸⁴ AGN, *Revised proposal Attachment 8.14: Risk prioritisation model*, January 2016.

¹⁸⁵ Cambridge Economic Policy Associates Ltd, *HSE/Ofgem: 10 year review of the Iron Mains Replacement Programme*, 2011, p. 27.

¹⁸⁶ Cambridge Economic Policy Associates Ltd, *HSE/Ofgem: 10 year review of the Iron Mains Replacement Programme*, 2011, pp. 52–72.

¹⁸⁷ AGN, *Mains Replacement Program Alternate Proposal to AER*, 1 March 2016, p. 1; HoustonKemp, *Cost-benefit analysis in the context of meeting safety standards*, February 2016, p. 11.

¹⁸⁸ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, pp. 12–13.

¹⁸⁹ AGN, *Revised proposal Attachment 8.10: Response to draft decision - mains replacement program*, January 2016, p. 13.

- We disagree with AGN that AS/NZS ISO 31000 merely requires that certain costings and other assessments be made as part of assessing risk treatment options. Section 5.5.2 of AS/NZS ISO 31000 states:

Selecting the most appropriate risk treatment option involves balancing the costs and efforts of implementation against the benefits derived, with regard to legal, regulatory, and other requirements such as social responsibility and the protection of the environment. Decisions should also take into account risks which can warrant risk treatment that is not justifiable on economic grounds, e.g. severe (high negative consequence) but rare (low likelihood) risks.

Section 5.5.2 clearly refers to a balance of cost and benefits to be undertaken in selecting risk treatment options. Benefits in addition to compliance with regulatory obligations (such as network efficiency benefits), should also be accounted for. In our view the practices set out in the Work Health and Safety Act 2012 and in AS/NZS ISO 31000 in regards to considering the cost and value of risk reduction accord with good practice when they are reasonably undertaken.

Finally, we note that Section 5.5.2 states that those risks that are not justifiable on economic grounds should be accounted for. In our view, this allows for the entity to mitigate the risks so long as the cost is not grossly disproportionate to the reduction in risk. An ALARP based CBA could therefore be provided.¹⁹⁰

¹⁹⁰ If the CBA is based on ALARP, then it is not expected that the result will be net benefit positive, i.e. we would not expect the benefits to exceed costs in monetary terms.