BUSINESS CASE - SA01

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA01
Project Name	SCADA Network Surveillance
Budget Category	SIB Capex
Priority	2
Reference Docs	
Confidentiality Claim	No
PROJECT APPROVAL	
Prepared By:	Robin Gray, *Manager Systems Operations, Networks SA* and Annabel Sandery, *Project Engineer*
Reviewed By:	Robin Gray, *Manager Systems Operations, Networks SA*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 PROJECT OVERVIEW

This project is associated with providing additional telemetered pressure monitoring sites, upgrading existing telemeter communication equipment that is expected to become obsolete, and replacement of communications and electronic flow devices that will reach the end of their useful lif over the next regulatory period.

The project scope includes:

- Installation of 24 new telemeters to monitor pressure at Transmission Pressure (TP) regulator locations;
- Installation of 32 new telemeters to monitor pressures at network extremity points, replacing chart recorders;
- Upgrade of existing telemeter modem equipment at 69 demand customer sites; and
- Time-based replacement of flow correctors at 25 demand customer sites;

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Maintain theme as it maintains network reliability.

2 COST AND TIMING

The costs of this project have been based on budget estimates of hardware and installation costs and the use of a combination of internal and contract resources.

A summary of Capex costs is provided in the table below. A detailed cost breakdown is included in Attachment A.

$'000 (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Telemetry – TP Regs	91.5	91.5	91.5	91.5	73.2	**439.2**
Telemetry - Chart Recorder Replacement	48	48	48	48	0	**192**
Telemetry Modem - Demand Customers	59.8	59.8	59.8	59.8	59.8	**299**
Flow Corrector Replacement	110.5	39.5	7.9	15.8	7.9	**181.5**

TOTAL	**309.8**	**238.8**	**207.2**	**215.1**	**140.9**	**1,112**

3 BACKGROUND

Gas is supplied to the Adelaide metropolitan High Pressure (HP) and Medium Pressure (MP) networks via 80 Transmission Pressure (TP) regulators. These form the primary supply to over 400,000 consumers within the South Australian network.

A program to provide real time SCADA pressure surveillance of these regulators has commenced, with 50 TP regulators expected to be completed by the end of the current regulatory period. Refer to Attachment B for site summary.

The primary driver for this program has been the reduction of risk associated with potential over or under pressure at these sites. These sites are physically checked every 3 months, however during the intervening period component failure (blocked filter, sleeve damage) could be left unchecked with potential for supply interruption and or system over-pressure. Real time monitoring of regulator supply pressures provides a "health" check of these facilities allowing timely diagnosis and rectification of equipment performance before problems arise.

The telemetry at these TP regulators also provides valuable real-time pressure data for network modelling purposes. Network modelling is used to assess network capacity in response to various load scenarios from which various operational decisions are made. The accuracy of these models is reliant on using actual field pressure conditions for validation purposes.

Currently there are 70 fixed chart recorders used to monitor pressures throughout the HP, MP and LP networks. This technology has been superseded by electronic data loggers which are more reliable, and require less maintenance as they do not have mechanical moving parts. A replacement program has commenced with 38 expected to be replaced in this current regulatory period with a further 32 to be replaced over the next regulatory period. Refer to Attachment C for site summary.

Detailed knowledge of flows and pressures throughout the network at any point in time allows for more effective and efficient responses to emergencies. Real time pressure surveillance allows pressures to be reduced and monitored during emergency repairs, maximising public safety and reducing the extent of supply outages.

The combination of network supply point and extremity point pressure surveillance will provide more accurate, reliable and timely data from which network capacity models can be validated. Validated network capacity models are essential for optimising system expansion, replacement and reinforcement in terms of timing and scope.

SCADA telemetry monitoring of flows at demand (>10TJ) metered sites was installed as part of the Full Retail Contestability (FRC) implementation in 2004. These sites provide gas day and intra gas day consumption data to retailers and the network market operator (AEMO) for management of the gas market. The communication protocols accessing this data are due to change with the move to the national networks SCADA platform in 2016-17 that is based on Telstra's 4G Network. Assessment of the existing 180 demand customer sites has highlighted that 69 sites will be incompatible with the 4G protocols, rendering the equipment obsolete. Refer to Attachment D for site summary.

In addition to technical obsolescence, replacement of electronic field equipment is necessary as the equipment begins to breakdown. Generally, electronic equipment has a life of about 10 years beyond which failures become more common with replacement the only option. Of the 180 demand consumer sites, 25 electronic flow correctors and 23 modems will exceed their 10 year life during the next regulatory period. It is therefore necessary to make provision for replacement of this equipment over the next regulatory period. Refer to Attachment E for site summary.

4 KEY DRIVERS & ASSUMPTIONS

The key drivers and assumptions for the recommended project are:

- Real time pressure monitoring of primary supply TP regulators is required to effectively manage supply risks(over pressure/under pressure);
- Pressure monitoring of TP regulators and downstream network extremity points will enable a more effective and efficient use of these resources in emergency situations, and optimisation of the scope and timing of augmentation projects;
- Fixed point chart recorders are obsolete;
- The communication protocol of modems at a number of Demand customer sites will become unusable when Telstra closes down the 2G network at the end of 2016. Also, the modems will be incompatible with moving to a national SCADA system based on Telstra 4G;
- Electronic field devices (flow correctors and modems) at Demand customer sites typically have a 10 year life span, beyond which a scheduled replacement program is required.

5 RISK ASSESSMENT

The lack of pressure information at critical points in the network has the potential for:

- Undiagnosed failure of a primary supply regulator facility with potential for network over/under pressure resulting in loss of supply to several thousand consumers and or damage to reticulation pipework;
- Extended response to containment of emergency situations (e.g major gas release as result of third party damage);
- Conservative network augmentation decisions, bringing capital expenditure forward prematurely; and
- Deferral of necessary network augmentation resulting in supply problems.

Maintaining real time SCADA monitoring of demand consumer sites is a regulatory requirement with hourly and daily consumption data required to be supplied to retailers and AEMO. Failure to provide accurate and timely data has potential financial penalties under the National Gas Market Rules.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk. The untreated risk associated with this project has been assessed as "High" given the risk associated with loss of supply and as such has been assigned a Priority 2. Refer to risk assessment matrix in Attachment F.

6 OPTIONS

With the exception of accepting the current risks, there are no alternatives.

Cost Benefit Analysis

Tangible benefits are difficult to quantify as the project is associated with reduction of operational risk and maintaining existing services to Demand consumers.

Capex / Opex Trade-off

While there will be a reduced level of maintenance associated with data loggers versus chart recorders, this is considered immaterial given the need for periodic site checks of electronic equipment, in addition to which more site visits will be required due to the increased number of stations.

7 JUSTIFICATION

Consistent with the requirements of Rule 79 of the National Gas Rules (NGR), AGN considers that the expenditure is:

- *Prudent* – The project is consistent with an asset owners obligation to: reduce risk; comply with regulatory requirements; and maintain accurate and up to date system performance data to optimise decision making;
- *Efficient* – The project will be undertaken with a mix of resources, experienced with design, construction and commissioning of these facilities, to ensure costs are maintained to as low as reasonably practicable. The work has been spread across the next regulatory period to ensure the project can be effectively resourced;
- *Consistent with accepted and good industry practice* – real time pressure surveillance is widely used within gas utilities; and
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – the project addresses risks associated with the operation of the network and making timely decisions necessary for the sustainable delivery of pipeline services.

The project specifically satisfies Rule 79 (2)(c) in that the various elements of this project are necessary to:

- Maintain and improve the safety of services – improved pressure surveillance will improve response to emergencies;
- Maintain the integrity of services - risks of regulator failure leading to network over/under pressure will be reduced; and
- Comply with regulatory obligation – under the NGR the network operator is obligated to provide reliable and timely demand site consumption data to the Market Operator (AEMO) and retailers for effective and efficient management of the gas market.

8 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken, then AGN will be exposed to:

- Potential for network over/under pressure;
- Extended response times and impact of major gas escapes;
- Poor timing of expenditure associated with network augmentation projects; and
- Potential penalties in not meeting NGR obligations for transfer of demand customer site data.

ATTACHMENT A – Detailed Cost Breakdown

Table 1: Installation Regulator Telemetry

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Sites	5	5	5	5	4	**24**
Telemeter Materials	50.0	50.0	50.0	50.0	40.0	**240.0**
Solar Panels	6.5	6.5	6.5	6.5	5.2	**31.2**
Labour* (@ $7k/site)	35.0	35.0	35.0	35.0	28.0	**168.0**
Total	**91.5**	**91.5**	**91.5**	**91.5**	**73.2**	**439.2**

* Labour derived from the following table

Description	$/hr	$/Day	$/Site
2 Systems monitoring Technician plus 1 vehicle (2 days)	140	1,120	2,240
2 Network Maintenance plus 1 vehicle (6 hours)	121	726	726
Supervisor 1 hr per job	94	94	94
Welder 4 hrs per job	85	680	340
Field crew - Backhoe, Team leader + Filed Op + Pantech and tipper	300	2,400	3,600
Total		4,700	7,000

Table 2: Replacement of Chart Recorders with Telemeters

$'000s (Real 2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Sites	8	8	8	8	0	**32**
Telemeter Materials	20	20	20	20	0	**80**
Solar Panels	10.4	10.4	10.4	10.4	0	**41.6**
Labour	17.6	17.6	17.6	17.6	0	**70.4**
Total	**48**	**48**	**48**	**48**	**0**	**192**

Labour cost based on 2 system monitoring Technicians plus 1 vehicle = $140/hr x 15.7 hrs each =$2,200

Table 3: Upgrade modems at Demand Customer sites

$'000s (Real 2014/15 – excluding overheads)							
Resources	**Sites**	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
LP1 (low complexity PLC*) upgrade	46	55.2	55.2	55.2	55.2	55.2	**276.0**
PC1 (medium complexity PLC) upgrade	13	3.6	2.4	2.4	2.4	2.4	**13.2**
CP10/11 (high complexity PLC) upgrade	10	2.0	2.0	2.0	2.0	2.0	**10.0**
Total	**69**	**60.8**	**59.6**	**59.6**	**59.6**	**59.6**	**299.2**

*Programmable Logic Controller

Table 4 Replacement Electronic Flow Corrector at Demand Customer sites

$'000s (Real 2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Units	14	5	1	2	1	25
EK220	54.5	19.5	3.9	7.8	3.9	89.5
Cabinet equipment	28	10	2	4	2	46
Labour for installation	28	10	2	4	2	46
Total	**110.5**	**39.5**	**7.9**	**15.8**	**7.9**	**181.5**

Labour cost based on 2 system monitoring Technicians plus 1 vehicle = $140/hr x 14.3 hrs each =$2,000

ATTACHMENT B – TP Regulator Site Summary

Reg	Customers	Primary Street Location	Suburb
135	9714	Tapleys Hill Rd	Seaton
331	4601	Cecila St	Brighton
310	4414	Grand Central Blvd	Hallett Cove
143	3514	Tapleys Hill Rd	Fulham
216	2414	Eastern Pde	Ottoway
406	1648	Hales Dr	Lonsdale
315	438	South Ave	Hallett Cove
1702	1000	Waterloo cnr Rd	Burton
324	4586	Augusta St	Glenelg
R118	7947	Golden Grove Road	Golden Grove
R144	2388	Montague Rd	Mawson Lakes
R110	7637	Wynn Vale Dr	Golden Grove
R140	900	Old Mill Rd	Nuriootpa
R139	617	Tusmore Ave	Tusmore
R125	5486	Refinery Rd	Ethelton
R211	11	Samcor	Kilburn
R215	450	Cormack Rd	Wingfield
R221	13	Churchill Rd	Ottoway
R318	437	Blacks Road	Flagstaff Hill
R321	568	Clark Tce	Glandore
R413	2	Kingston Ave	Richmond
R414	7	Frank St	Marino
R1704	1000	Tina Dr	Modbury Nth
R799	1000	Frost Rd	Salisbury Sth

ATTACHMENT C – Chart Recorder Site Summary

Network	Site Location
High Pressure	Portrush Rd
High Pressure	Newton St-Clovelly Pk
High Pressure	Schilling Rd - Angaston
High Pressure	Kapara Rd-Gilman
Medium Pressure	Russell Rd-Athelstone
Medium Pressure	Norman Rd-Fairview Pk (Yatala Vale Rd)
Medium Pressure	Sir Keith Smith Dr-Northhaven
Medium Pressure	Trim Dr-Ridgehaven
Medium Pressure	Delfin Dr-West Lakes
Medium Pressure	Chesterman Rd-Elizabeth Field
Medium Pressure	Findon Rd-Flinders Pk
Medium Pressure	Homer Rd-Clarence Pk
Medium Pressure	Boothby St-Panorama
Medium Pressure	Port Rd-West Croydon
High Pressure	Golden Grove Rd-Greenwith
High Pressure	Curtis Rd-Andrews Farm
High Pressure	Uley Rd-Graigmore
High Pressure	Coromandel Pde-Cormandel Valley
High Pressure	Julina Tce-Gawler
High Pressure	Aldinga Beach Rd-Aldinga Beach
High Pressure	Morphett Rd-Dover Gdns (MRP)
Medium Pressure	Cnr Regency Rd & Prospect Rd
Medium Pressure	Northfield
Medium Pressure	Ridley Gve-Woodville Gdns
Medium Pressure	Ryans Rd-Parafield Gdns
Medium Pressure	Elizabeth Way-Elizabeth
Medium Pressure	Dernancourt
Medium Pressure	Esplanade-Hove
Medium Pressure	Joy St-Ascot Pk
Medium Pressure	Glenelg Nth
Medium Pressure	Trimmer Pde-Grange
Medium Pressure	Grove Ave-Marleston

ATTACHMENT D – Modem Upgrade (GSM/PSTN to 3G) Site Summary

Equipment No.	Name
O652	Gepps Cross Gate Station
O157	Katnook
O599	Wasleys-gate station
O653	Elizabeth gate Station
M181	Radisson Playford Hotel - CBD
P665	MT GAMBIER PRESSURE SITE
P666	OLD NOARLUNGA PRESSURE SITE
G635	G635 Norris Bell Alice Springs 2
P667	Noarlunga Downs Pressure Site
P668	Huntfield Heights Pressure Site
P664	WHYALLA NORRIEÿ
P669	Kudla Pressure Site
M317	Department of the Arts - CBD
M328	DSTO Defence Centre - North
M316	S. Smith and Sons P/L - Angaston
M314	Whyalla Hospital
M215	Repatriation Hospital - South
M298	Big River Pork - Murray Bridge
M290	Carter Holt Harvey - Commercial St.(MT GAMBIER)
M311	Mildura Base Hospital
M299	Ridley Agriproducts (Murray Bridge)
M310	Mildura Waves
M318	Vall's Styrene Packaging (BERRI)
M296	R-Max - North
M216	Hampstead Rehabilitation - North
M278	NCCRA INC Meter 1 - South
M303	Perpetual Hydroponics Shed - North
M306	Foamex SA - North
M229	Flinders University (Bedford Park) - South
M269	Lyell McEwin Hospital Inc - North
M189	Buttercap Bakeries - South
M267	Sankey Australia - South
M198	Dept of Correctional Services - North
M180	St Andrews Hospital Cogen - CBD
M272	Healthscope (Modbury Public Hospital) - East
M163	Industrial Engineers and Springmakers - West
M182	Stamford Plaza - CBD
M312	Intercast & Forge - West
M256	SA R&D Institute - East
M315	University Of Adelaide - CBD
M304	Mobil Oil - West
M263	Stamford Grand Hotel - Glenelg - West
M264	Adelaide Festival Centre - CBD
M254	The Adelaide Casino (Adelaide) - CBD
M300	Carter Holt Harvey Panels

Equipment No.	Name
M279	Bushman Tanks (Cavan) - North
M174	Inghams Enterprises (Mile End) - West
M295	Balfours - Dudley Pk - North
M305	Torrens Transit (Newton) - East
M255	North Eastern Community Hospital 2 - East
M294	Andpak Aust.
M218	Boral Hollostone Masonary - North
M280	Safcol Canning - North
M197	Hilton International Adelaide - CBD
M257	CSR Humes - North
M203	Adelaide Galvanising - Cavan
M277	Walker Australia - South
M202	Top Coat Asphalt
M213	Intercontinental (Ex Hyatt Regency)Adelaide - CBD
O655	Taperoo Gate Station
O014	Berri Reg2
O670	Berri Township Reg2
O637	Site 56 Berri Offtake
O657	Port Pirie Gate Station
O654	Whyalla Gate Station
G090	Site 57 Mildura Gate
G634	G634 AS City Gate
G102	G102 Interconnect
M084	SOUTHCORP WINES - Karadoc

ATTACHMENT E – Flow Corrector Replacement Sites

Site No	Customer	Suburb
M078	BRICKWORKS LTD (Austral Bricks)	GOLDEN GROVE
M106	CSR BUILDING MATERIALS	GOLDEN GROVE
M073	G H MICHELL & SONS PTY LTD	SALISBURY SOUTH
M211	INTERNATIONAL LINEN SERVICE PTY LTD	TORRENSVILLE
M131	WOMEN'S & CHILDREN'S HOSPITAL	NORTH ADELAIDE
M023	NEW CASTALLOY (Formerly Ion Automotive)	NORTH PLYMPTON
M161	O-I (ADELAIDE PLANT)	WEST CROYDON
M151	SAN REMO MACARONI CO PTY LTD	WINDSOR GARDENS
M115	SOUTH AUSTRALIAN BREWING CO PTY LTD	THEBARTON
M160	TARAC TECHNOLOGIES PTY LTD (SAMUEL RD)	NURIOOTPA
M024	THE SMITH'S SNACKFOOD COMPANY LTD	REGENCY PARK
M228	TORRENS TRANSIT (Mile End South)	MILE END SOUTH
M305	TORRENS TRANSIT (Newton)	NEWTON
M084	TREASURY WINE ESTATES (prev Southcorp)	KARADOC
M208	TIP TOP BAKERIES	DRY CREEK
M328	DSTO - DEFENCE CENTRE	EDINBURGH
M034	ELECTROLUX COOKING PRODUCTS DIVISION	DUDLEY PARK
M298	BIG RIVER PORK	MURRAY BRIDGE
M649	COMO GLASS HOUSE	KORUNYE
M660	TORRENS TRANSIT (Camden Park)	CAMDEN PARK
M156	COOPERS BREWERY	REGENCY PARK
M159	UNIVERSITY OF SA (Mawson Lakes)	MAWSON LAKES
M226	INGHAMS ENTERPRISES PTY LTD (Burton)	BURTON
M074	HOLDEN LTD	ELIZABETH SOUTH
M112	ARROWCREST GROUP PTY LTD	WOODVILLE NORTH

ATTACHMENT F – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*N/A*	*N/A*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*N/A*	*N/A*	*Significant*	*Minor*	*Minor*	*Medium*	*Medium*	
	Risk Level	*N/A*	*N/A*	*High*	*Low*	*Low*	*Moderate*	*Moderate*	***64***
				20	*8*	*8*	*14*	*14*	
Residual Risk	**Likelihood**	*N/A*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*N/A*	*N/A*	*Significant*	*Minor*	*Minor*	*Medium*	*Medium*	
	Risk Level	*N/A*	*N/A*	*Moderate*	*Negligible*	*Negligible*	*Low*	*Low*	***31***
				13	*03*	*03*	*06*	*06*	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA06

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA06
Project Name	Installation of Impressed Current Corrosion Protection Units
Budget Category	SIB CAPEX
Priority	3
Reference Docs	
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Annabel Sandery, *Project Engineer* and Robin Gray, *Manager Systems Operations*
Reviewed By:	Robin Gray, *Manager Systems Operations*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 *PROJECT OVERVIEW*

This project is a continuation of a current program to replace a system of sacrificial anodes with telemetered impressed current corrosion protection (ICCP) units in the coated steel distribution networks. Twelve units have been installed over the last 10 years, and 6 units will be installed in the next regulatory period.

ICCP units improve corrosion protection and reduce maintenance cost on the mains protected by these units.

The project scope includes:

- Design of ICCP units;
- Installation of transformer rectifier units and associate ground bed anodes;
- Thermo weld connection to existing steel mains; and
- Installation and commissioning of ICCP unit telemetry.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Maintain theme as it maintains network reliability and safety.

2 *COST AND TIMING*

The scope of work of the project has been based on the installation of 6 ICCP units over a 3-year period. Two units per year will be installed over a 3-year period.

The cost of this project has been based on materials and labour for similar installations undertaken in the current regulatory period.

A summary of costs is provided in the Table below. A detailed cost breakdown is included in Attachment A.

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Materials	70	70	70			**210**
Installation & Commissioning	54	54	54			**162**
Total	**124**	**124**	**124**			**372**

3 BACKGROUND

Steel mains within the South Australian transmission, high and medium pressure networks form part of the trunk main infrastructure supplying gas to over 410,000 consumers.

To protect these mains from corrosion they are externally coated with either coal tar enamel, polyethylene, fusion bonded epoxy (FBE) or tri-laminate and cathodically protected (CP) using impressed current or galvanic sacrificial anodes.

CP of these mains has relied largely on galvanic anodes (buried underground at regular intervals) which require regular physical checking of on-site voltage potentials to ensure adequate corrosion protection is being maintained. Sacrificial anodes, while relatively cost effective to install and require no maintenance after burial, are suited to circumstances where there is low soil resistivity and corrosion protection current requirements are relatively low (e.g. good pipeline coatings).

An impressed current corrosion protection (ICCP) system provides more effective and reliable corrosion protection, particularly in soils with high resistivity, and where high corrosion protection currents are required (e.g. at coating defects). ICCP can be adjusted to provide the right level of protection (current), compensating for coating defects, and can be monitored remotely (through SCADA), enabling a timely response to corrosion issues. While these systems require additional periodic maintenance to ensure the transformer rectifier units (TRU) are functioning properly, this is offset by savings in field trips to obtain on-site voltage potential readings (in addition to providing a more reliable level of corrosion protection).

With approximately 700 km of steel trunk main (replacement value circa $350M) it is important that the integrity of these assets is maintained to avoid premature replacement. Fundamental to this is an effective corrosion protective system.

A program commenced during the current regulatory period to upgrade the corrosion protection on mains where existing sacrificial anodes have been shown to be ineffective in providing adequate corrosion protection. Eight impressed current units have been installed during the current regulatory period, and this project is a continuation of that work.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for this project are:

- The use of an impressed current system provides a more effective corrosion protection system than sacrificial anodes;
- Sacrificial anodes on sections of steel mains are unable to maintain adequate corrosion protection;
- The impressed current system can be effectively monitored remotely, enabling a more timely identification and response to corrosion issues; and
- An impressed current system results in lower maintenance costs.

5 RISK ASSESSMENT

The key issues addressed by this proposal are:

- Maintaining the integrity and life of the existing asset; and
- Avoidance of corrosion on principal trunk mains that could result in a major gas escape impacting public safety and reliability of supply

Where sacrificial anodes have been shown to be ineffective in maintaining adequate voltage potentials, particularly at coating defect sites, there is a risk of containment loss as result of undetected corrosion.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria.

The untreated risk associated with this project has been assessed as "Moderate" and has been assigned Priority 3. Refer to the risk assessment matrix in Attachment B.

6 OPTIONS

There are no other alternatives other than to rely on the existing sacrificial anode system for corrosion protection.

Cost Benefit Analysis

The primary benefit of this proposal is to minimise the risk of inadequate corrosion protection of major steel trunk mains. This is difficult to quantify, however, it is regarded that an ICCP system provides more effective corrosion protection thereby maximising the asset's useful life.

The majority of steel mains within the South Australian distribution system are between 30 and 45 years old with a replacement value of circa $350M (700 km). The installation of ICCP could reduce long term capital requirements by extending the life of these assets.

The life of a sacrificial anode depends on a number of factors and can range between 15-20 years. Given that the majority of steel mains are of the order of 30 years old, it is expected that between

200-300 anodes could require replacement (at $4,000 per anode) over the next 10 years. The installation of additional ICCP units would avoid this replacement.

Based on 200 anodes to be replaced over the next 10 years (20 per year @ $4,000 per anode) the net present cost (NPC 10%, 10 years) of anode replacement in 10 years is about $490k which is greater than the cost of ICCP units.

In addition to the above, maintenance resource savings of about $85k per annum could be expected (see below) with a payback on investment less than 5 years.

The installation of ICCP units is considered the most cost effective long term means of corrosion protection.

Capex / Opex Trade-off

As discussed above, it is recognised that ICCP systems require additional maintenance to ensure the TRUs are functioning appropriately, however this is offset by efficiencies associated with remote monitoring of corrosion potentials. It is expected that once all ICCP units are installed, maintenance resources can be reduced by 1 FTE or $85k per year (for CP Technician) by reducing the number of CP test point sites and avoidance of annual anode replacement programs. The savings will accrue from 2019/20.

7 JUSTIFICATION

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules (NGR), AGN considers that the capital expenditure that it is seeking is:

- *Prudent* – Inadequate corrosion protection can lead to premature failure requiring additional maintenance or mains replacement capital costs.
- *Efficient* –the cost estimates for this project are based on the costs of similar installations carried out over the last few years utilising experienced contractors and internal resources. As detailed in Section 6 above, this project proposal has a payback of less than 5 years.
- *Consistent with accepted and good industry practice* – it is generally accepted across the industry that impressed current systems provide more effective corrosion protection than anode systems. Maintaining network integrity and reducing risks of major failures are code requirements as outline in AS2285 (transmission pipeline code) and AS 4645 (distribution network code.
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – the project will enable the life of the existing assets to be maintained longer than maintaining sacrificial anode systems. Deferring replacement of assets is consistent with maintaining the lowest sustainable cost of gas service delivery. The ICCP units will avoid future replacement expenditure associate with sacrificial anodes, and deliver maintenance savings.

AGN therefore considers that the capital expenditure is justifiable under 79(1)(b) rule and rules 79(2)(a) and 79(2)(c) (i) and (ii) of the NGR as the expenditure as the overall economic value of the expenditure is positive necessary in order to maintain and improve the safety integrity of services.

8 PROJECT DELIVERY

The project is a continuation of current works, and will continue to be delivered in and efficient manner by qualified contractors and supervised by internal personnel.

10 CONSEQUENCES OF NOT PROCEEDING

If the project is not continued, AGN will not be optimising the protection of a key class of assets and not be undertaking the most efficient means of service delivery.

ATTACHMENT A – Detailed Cost Breakdown

The cost of each unit and installation is:

[redacted]

- Total $62,000

Six units @ $62,000 = $372,000

ATTACHMENT B – Risk Assessment

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance	Financial Impact	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
	Consequence	*Medium*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Insignificant*	
	Risk Level	*Moderate*	*Low*	*Moderate*	*Low*	*Low*	*Moderate*	*Negligible*	
		12	*05*	*12*	*05*	*05*	*12*	*02*	*53*
Residual Risk	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Major*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Insignificant*	
	Risk Level	*Low*	*Negligible*	*Low*	*Negligible*	*Negligible*	*Low*	*Negligible*	
		06	*03*	*06*	*03*	*03*	*06*	*01*	*28*

Priority		**Priority Description**
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA08

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA08
Project Name	I&C Meter Set Refurbishment
Budget Category	Capex
Risk and Priority	Moderate, Priority 3
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Robin Gray, *Manager Systems Operations* and Annabel Sandery, *Project Engineer*
Reviewed By:	Robin Gray, *Manager Systems Operations*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	The protective paint on 800 elevated pressure Industrial and Commercial (I&C) meter sets in Australian Gas Networks' (AGN) South Australian network has deteriorated to such an extent that corrosion of meter assembly pipe works, valves and fittings is becoming a problem. If left untreated, the corrosion of these meter sets could lead to gas leaks and/or component failure (e.g. the valves seize) resulting in the interruption of supply to customers. The untreated risk associated with these meters has been rated as Moderate. To address the risks posed by the corrosion of these meter sets, AGN commenced a refurbishment program in 2010, which involves grit blasting and painting the meter sets. By the end of the AAP 300 meter sets will have been refurbished.
Options Considered	Three options were considered as part of this business case: • Option 1 – Cease the current refurbishment program in the next AAP, which would leave AGN exposed to the risk of a gas leak and/or component failure, resulting in an interruption to supply. • Option 2 – Continue the refurbishment program in the next AAP, by refurbishing the remaining 500 at risk I&C meter sets. This option mitigates the risk posed by corroded meter sets at an estimated cost of $3,480 per meter set (or $1.76 million over the AAP). • Option 3 – Replace the remaining 500 at risk I&C meter sets. This option mitigates the risk posed by corroded meter sets at an estimated cost of $7,000 per meter set (or $3.5 million over the AAP).
Option Selected	Option 2 has been selected because it is the most cost-effective method to mitigate the risks.
Estimated Cost	The forecast capital expenditure for the refurbishment option in the next AAP is $1.76 million (real $2014/15).
Consistency with the NGR	The refurbishment of at risk I&C meters complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services (rule 79(1)(b) and rules 79(2)(c)(i) and (ii)); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (rule 79(1)(a)).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue to provide a safe and reliable supply of natural gas to our customers. More information on our stakeholder engagement program and results is

	provided in Chapter 3 of the Access Arrangement Information (AAI).

2 Background

The South Australian network has approximately 9,000 I&C meter sets of various configurations and sizes. Of the 9,000 I&C meters installed, there are approximately 2,000 elevated pressure meter sets with large regulators, filters, pilots and OPSO valves fitted. While the meters on these sets are changed on a 10-year basis, the meter assembly (pipe work, valves and regulators) have remained unchanged, with some installations up to 30-45 years old.

The preventative maintenance for these larger meter assemblies typically involves mechanical and instrumentation checks with minimal "touch up"[1] painting only carried out if necessary. However, the external condition on elevated pressure meter sets is reaching a level where touch up painting is no longer sufficient to effectively maintain the meters. This is because the protective paint has deteriorated to such an extent that corrosion of meter assembly pipe works, valves and fittings is becoming a problem. Significant corrosion has been observed on a number of meter sets and there have also been instances where pipework, at the air and soil interface, has failed due to the extensive corrosion.

To address the risk, AGN commenced a refurbishment program in 2010, which involves on-site grit blasting and extensive repainting[2] of the 800 elevated pressure meters that have been identified as being most at risk because of poor external condition. This program was approved by the AER in the last AA review and by the end of the current AAP, 300 meter sets are expected to be refurbished leaving another 500 to be refurbished in the next AAP.

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of stakeholders. During this engagement, stakeholders clearly indicated that they viewed gas as a reliable source of energy and indicated that they would like high levels of safety and reliability maintained. Consistent with the above insight, continued refurbishment of at risk I&C meter sets/assemblies will enable AGN to continue to provide a safe and reliable supply of natural gas to customers.

3 Risk Assessment

The key risk posed by the corroded meter sets is that the corrosion lead to gas leaks and/or component failure (e.g. the valves seize) and results in the interruption of supply to customers.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. In short, the untreated risk associated with the corrosion has been assessed as "Moderate" and assigned a Priority 2 rating. Further detail on the risk assessment that has been carried out can be found in Attachment B.

[1] Touch up painting consists of cleaning and grinding spots with little or no paint cover and reapplying new paint. This work is done by internal crew as part of preventative maintenance.

[2] More extensive painting consists of completely grit blasting the meter set and reapplying new paint. This work is done by a contractor.

4 Key Drivers and Assumptions

The key assumptions and drivers for the project are set out below:

- The corrosion of meter assembly pipe works, valves and fittings has reached a point where a comprehensive program of on-site grist blasting and repainting is required to ensure the life of the asset can be maximised.
- 800 meter sets have been identified as being in the poorest condition, of which 300 will be refurbished by the end of the current AAP and a further 500 in the upcoming AAP.
- External contract resources will be used to undertake the proposed site works.
- The project is consistent with AGN's operational theme of "Maintain" network safety. It specifically relates to the following insights:
  - Customers value AGN's high reliability and want AGN to keep providing the same (as a minimum) service levels.
  - Customers view gas as a reliable source of energy.

5 Options

Three options have been considered as part of this business case:

- Option 1 – Cease the refurbishment program that commenced in this AAP.
- Option 2 – Continue the refurbishment program in the next AAP by refurbishing the remaining 500 I&C meter sets through on-site grit blasting and repainting.
- Option 3 – Replace the 500 I&C meter sets.

Cost and Benefits of Options

Item	Option 1 Stop the program	Option 2 Refurbish 500 I&C meter sets	Option 3 Replace 500 I&C meter sets
Costs/ Risks	If the 500 I&C meter sets that have been identified as being in poor condition are not refurbished or replaced there is a risk that corrosion activity will cause a gas leak, or component failure and an interruption of supply. The life of the external pipe work valves and fittings can also be expected to be substantially reduced and future repairs more expensive than refurbishment costs in the medium to longer term.	$1.74 million (real $2014/15) over the AAP, or $3,480 per meter set (see next section for further detail).	$3.5 million (real $2014/15) over the AAP, or $7,000 per meter set.
Benefits	No upfront costs to refurbish or replace the meter sets.	This option provides effective mitigation of the risks associated with corroded meter sets, at the least cost.	This option effectively mitigates the risks associated with corroded meter sets.

As this table highlights, Option 1 will do nothing to reduce the risks posed by the corrosion and over the medium to longer term is expected to be more costly than Option 2. Options 2 and 3 on the other hand, will reduce the risks but the costs of risk mitigation differ, with Option 2 being more cost effective than Option 3. Option 2 has therefore been chosen to rectify the risks posed by corroded meter sets and is considered consistent with the action that a prudent operator would take.

6 Forecast Cost for the Upcoming AAP

The table below provides a summary of the capital expenditure that is forecast to be incurred in the next AAP refurbishing the remaining 500 I&C meter sets.

Capital Expenditure ($'000s Real $2014/15 – excluding overheads)

Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
External Resources	340	340	340	340	340	**1,700**
Internal Resources	12	12	12	12	12	**60**
Total	**352**	**352**	**352**	**352**	**352**	**1,760**

The forecast has been based on the average costs that have been incurred refurbishing the I&C meters in 2014, which has been carried out using a combination of internal and external resources. The external resources have been used for grit blasting and painting and were selected through a competitive tender process. The internal resources have been used for field supervision and customer liaison and are based on APA's internal rates. A more detailed cost breakdown is provided in Attachment A.

7 Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the proposed expenditure is:

- *Prudent* – This expenditure is necessary in order to improve the safety and maintain the integrity of services because unchecked corrosion activity could lead to gas leaks and/or component failure resulting in the interruption of gas supply. The expenditure is therefore of a nature that a prudent service provider would incur.
- *Efficient* – Without the proposed expenditure the external pipe work valves and fittings can be expected to further deteriorate and corrode, reducing the life of these assets and/or making future repairs more expensive. When coupled with the fact that Option 2 is the most cost effective option and will be carried out in the least cost manner by using a combination of internal and external resources, the proposed expenditure can be considered consistent with what a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – It is good industry practice to identify risks and take action to address those risks, and to ensure that assets undergo refurbishment when required to extend asset life.

- *To achieve the lowest sustainable cost of delivering pipeline services* – The proposed project is necessary to maximise the life of the I&C meter sets that have been identified as being in poor condition. Without the proposed expenditure the external pipe work valves and fittings would further deteriorate and corrode, reducing the life of these assets and making future repairs more expensive. In the long term, the costs of not undertaking the proposed project would be considerably greater. The proposed expenditure is therefore consistent with the objective of achieving the lowest sustainable cost of delivering pipeline services.

It follows from these observations that the capital expenditure is consistent with rule 79(1)(a) of the National Gas Rules. The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)).

ATTACHMENT A – Detailed Cost Breakdown

The tables below provide a breakdown of the cost of refurbishing a single meter set and the annual costs for the next AAP. All the costs in these tables are expressed in real $2014/15 values and exclude overheads.

Estimation of Refurbishment Costs per Meter Set ($2014/15)

Cost item	Cost
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Estimation of Refurbishment Costs for 500 Meter Sets

	2016/17	2017/18	2018/19	2019/20	2020/21	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

ATTACHMENT B – Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the refurbishment of I&C meter sets is not undertaken (untreated risk), while the bottom panel sets out the residual risks if the refurbishment works are implemented. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	*Medium*	
	Risk Level	*Low*	*Low*	*Low*	*Low*	*Low*	*Low*	*Moderate*	***62***
		08	*08*	*08*	*08*	*08*	*08*	*14*	
Residual Risk	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	*Minor*	*Medium*	
	Risk Level	*Negligible*	*Negligible*	*Negligible*	*Negligible*	*Negligible*	*Negligible*	*Low*	***24***
		03	*03*	*03*	*03*	*03*	*03*	*06*	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

APA Group

BUSINESS CASE - SA09

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA09
Project Name	Valve Corrosion Protection
Budget Category	Capex
Risk and Priority	High, Priority 2
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Robin Gray, *Manager Systems Operations* and Tom Bloch, *Project Engineer*
Reviewed By:	Robin Gray, *Manager Systems Operations*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	This project is a continuation of Australian Gas Network's (AGN) remediation of critical isolation valves located in underground valve pits in the South Australian gas distribution network. Inspections have highlighted significant corrosion activity that, left unchecked, poses a significant risk to the safe and reliable supply of gas. The risk associated with these valves has been assessed as High from an operational perspective. The remediation involves grit blasting the valves in situ and coating them to protect against further corrosion. The program commenced in 2010 with 170 valves expected to be completed by the end of this Access Arrangement Period (AAP), with a further 80 valves to be completed over the AAP.
Options Considered	Three options have been considered as part of this business case: • Option 1 – Do nothing. • Option 2 – Continue the valve recoating program on the 80 remaining critical isolation valves at a cost of $0.311 million (or $3,887.50 per valve). • Option 3 - Replace the remaining 80 critical isolation valves at a cost of $0.8-$1.6 million (or $10,000-$20,000 per valve).
Option Selected	Option 2 has been selected because: • it is more cost effective than Option 3; and • Option 1 will do nothing to reduce the risk posed by the corrosion and could give rise to much higher costs in the longer run as the corrosion accelerates and if a significant leak occurs.
Estimated Cost	The forecast capital expenditure requirement for the remediation work in the upcoming AAP is $0.311 million (real $2014/15).
Consistency with the NGR	This remediation of corrosion of critical isolation valves complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services (rules 79(1)(b) and 79(2)(c)(i) and (ii)); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (rule 79(1)(a)).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue to provide a safe and reliable supply of natural gas to our

	customers. See Chapter 3 of the Access Arrangement Information (AAI) for further detail.

2 Background

There are 250 key network isolation valves within the network. These valves are:

- Primary isolation valves on primary mains to over 400,000 consumers.
- Critical for isolation and pressure control in event of a major gas escape.
- Generally located on major trunk mains or branches off the major trunk mains within major transport corridors.

The valves are located in underground concrete and brick chambers accessed via a small manhole cover located in the roadway or footpath. These chambers are susceptible to accelerated corrosion due to the wet environment. The high humidity created by the lack of ventilation and constant presence of water results in corrosion pitting, which if left unchecked, could result in these valves being inoperable, particularly for emergency isolation and pressure control. Consequences include a major gas escape, creating a risk to the public as well as to maintenance personnel.

The valves that are buried in the smaller 300mm diameter chambers also contain a cavity where there is no soil contact. These valves are wrapped and not able to be visually checked for corrosion unless they are excavated.

The valves in small chambers are subject to stresses placed on them by heavy traffic pushing down on the chamber to the valve. This can damage the protective wrapping allowing corrosion to form on the body of the valve, which may make it inoperable. In a worst case scenario corrosion could penetrate the adjoining pipe with potential for a major gas escape.

Cathodic protection (CP), which normally protects the steel main from corrosion, is not effective in these valve pits or small chamber locations as there is no contact with the soil to make the electrical connection. Corrosion protection is provided by specially applied paint coating, in some cases combined with pipe wrapping.

It has been over 20 years since a major coating application, with various amounts of "touch up" painting undertaken over the years during routine inspections. The condition of this paintwork has deteriorated to the point that touch up painting is no longer an appropriate process.

Engineering inspections and maintenance feedback has highlighted that:

(a) Corrosion pitting has been gradually progressing in all valve pits over time to a point that a remediation program is required before ongoing corrosion becomes critical; and

(b) Periodical maintenance, as relied upon to-date, will no longer be effective in stemming the degradation and will not be cost effective.

Some of the corrosion found has resulted in costly repairs involving grit blasting and wall thickness inspection to ensure the integrity of the pipe has not been compromised. Figure 1 illustrates the condition of some of the valves.

Figure 1: Isolation Valves located in Vaults - Examples

New coating standards and materials are now available with special corrosion inhibitors, which protect the pipe and valves in valve chambers for 30 to 40 years when properly applied.

A valve recoating program was approved by the AER in the last AA review and has been in place for the past few years with about 170 of the 250 valves expected to be completed by the end of the current AAP. Refer to Attachment B for valve site list. The recoating program involves exposing the valve, grit blast the pipe and valves in these chambers and then apply the special corrosion inhibitor coating. This program avoids expensive replacement should the valve become inoperable. If the latter occurs, the pipeline must be shut down using hot tap and stopple equipment, a section cut out, and a new valve installed. The cost of replacing the valve can vary between \$10,000 and \$20,000.

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to maintain our high levels safety and reliability. Consistent with the above insight, the remediation of corrosion on critical isolation valves will enable AGN to continue to provide a safe and reliable supply of natural gas to customers.

3 Risk Assessment

The risks associated with the corrosion of critical isolation valves are that:

- a significant gas leak may occur, which necessitates emergency response and repair and an interruption to supply to customers and businesses;
- the valves become inoperable; and
- maintenance costs will increase as the corrosion accelerates.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. Further detail on the risk assessment that has been carried out can be found in Attachment C. In short, the untreated risk associated with the critical isolation valves has been assessed as "High" given the risk associated with a major gas escape resulting in an interruption to supply, and has been assigned a Priority 2 rating.

4 Key Drivers and Assumptions

The key assumptions and drivers for the project are as follows:

- Engineering inspections and maintenance feedback has highlighted that corrosion pitting is progressing to a point that the remediation program must continue to avoid ongoing corrosion.
- Touch up painting is no longer effective in protecting these valves from corrosion with in situ grit blasting and coating the only effective solution.
- Severe valve corrosion could render the valve inoperable affecting control of major gas escape potentially impacting several thousand consumers.
- The project is consistent with AGN's operational theme of "Maintain" network safety. It specifically relates to the following insights:
  - Customers value AGN's high reliability and want AGN to keep providing the same (as a minimum) service levels.
  - Customers view gas as a reliable source of energy.

5 Options

Three options have been identified to deal with the risks posed by the corrosion of critical isolation valves:

- Option 1 – Do nothing.
- Option 2 – Continue the valve recoating program on the 80 remaining critical isolation valves.
- Option 3 - Replace the remaining 80 critical isolation valves.

The costs and benefits associated with these three options are summarised in the table below. As this table highlights, Option 1 will do nothing to reduce the risk posed by the corrosion and could give rise to much higher costs in the longer run as the corrosion accelerates and if a significant leak occurs. In contrast to Option 1, options 2 and 3 will both reduce the risks posed by the corrosion, but the cost of replacing the valves before the end of their lives is 2.6-5.1 times more expensive than carrying out the recoating program. Option 2 is therefore more cost effective than Option 3 and has been selected.

Costs and benefits of the options

Item	Option 1 Do Nothing	Option 2 Valve Recoating Program	Option 3 Replace 80 Critical Valves
Costs/Risks	Risk that corrosion results in: • a significant gas leak, which gives rise to emergency repair costs and interrupts supply to 3,000-15,000 customers (the cost of relighting this number of customers ranges from $0.15-$1.5 million); • the valves becoming inoperable and having to be replaced at a cost of $10,000-$20,000 per valve; and • higher ongoing maintenance costs as the corrosion accelerates.	$0.311 million (real $2014/15) (or $3,887 per valve)	$0.8-$1.6 million (real $2014/15) (or $10,000-$20,000 per valve)
Benefits	No upfront costs.	Both the recoating and replacement program will reduce the operational risk from High to Moderate because they reduce the risk of: • a significant gas leak and the costs associated with carrying out emergency repairs and customer relights; • valves becoming inoperable and so avoids the costs of replacing the valves before the end of their lives; and • higher ongoing maintenance costs as the corrosion accelerates.	

6 Forecast Cost for the Upcoming AAP

The valve recoating program in the next AAP will involve grit blasting and recoating the remaining 80 isolation valves at a rate of 16 per year using external contractors for excavation and coating, with supervision by an internal supervisor and engineer to ensure that the coating is applied correctly, maximising the effective life of the coating.

The following table sets out the forecast capital expenditure associated with this work over the next AAP, which has been based on the following assumptions:

- A coating contractor with confined space accreditation, is contracted to grit blast and paint the valves and pipe work. The cost of this work is based on the average cost of recently completed work.
- One internal supervisor, one technician and one assistant are used for auditing and confined space set up. The cost of this work is based on APA's current internal rates.

- One field crew is contracted to carry out the excavation work. The cost of this work is based on current contractor rates.
- Traffic control crew are contracted. The cost of this work is based on current contractor rates.

The timing of the recoating has been scheduled to ensure adequate capacity of resources to undertake the program of work. The program to-date has confirmed contractors have capacity to deliver the planned program of work.

A more detailed breakdown of the cost is provided in Attachment A.

Capital expenditure forecast excluding overheads ($'000 real $2014/15)

Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Contractor Costs	34.6	34.6	34.6	34.6	34.6	**173**
Direct Labour Costs	27.6	27.6	27.6	27.6	27.6	**138**
Total	**62.2**	**62.2**	**62.2**	**62.2**	**62.2**	**311**

7 Consistency with National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the capital expenditure is:

- *Prudent* – The expenditure is necessary in order to maintain and improve the safety of services and maintain the integrity of services and is of a nature that a prudent service provider would incur. These valves are critical for emergency isolation and pressure control. Failing to arrest the current corrosion activity could render these valves inoperable, or result in a significant gas escape.
- *Efficient* – The work program is the only practical and effective option to efficiently address the risk posed by the corrosion of these valves. The cost of carrying out the work is based on the current costs of undertaking such work, which will involve the use of specialist contractor resources, other external contractor resources and internal supervision. The contractor rates are based on competitively tendered rates. The expenditure is therefore of a nature that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – Addressing the risks associated with the corrosion and poor condition of critical isolation valves is considered to be essential and consistent with the requirement in Australian Standards AS4645 and AS2885 that risks be managed risks to as low as reasonably practicable and in a manner that balances costs and risks.
- *To achieve the lowest sustainable cost of delivering pipeline services* – If the project does not continue additional costs may be incurred with the emergency response and repair of gas leaks and ongoing maintenance costs associated with accelerated corrosion. The expenditure is therefore consistent with the objective of achieving the lowest sustainable cost of delivery.

The capital expenditure can therefore be viewed as being consistent with rule 79(1)(a) of the National Gas Rules. The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)).

ATTACHMENT A – Detailed Cost Breakdown

The table below provides a detailed breakdown of the valve refurbishment unit costs set out in Section 6.

$ (Real 2014/15 – excluding overheads)	
Item	**Cost**
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
Total Unit Cost	**3,884**
Annual Valve Refurbishment – No.	16
Total Annual Cost	**62,144**

ATTACHMENT B – Valve Site List

Valve ID	USID	Address
5951041	5081716	OSBORN TERRACE PLYMPTON 5038 SA
5970167	3405536	DRAYTON STREET HINDMARSH 5007 SA
5955322	3580464	NEWTON ROAD CAMPBELLTOWN 5074 SA
5959001	6399077	COMMERCIAL ROAD ELIZABETH SOUTH 5112 SA
5969136	3251501	MAIN SOUTH ROAD OHALLORAN HILL 5158 SA
5969140	3251501	MAIN SOUTH ROAD OHALLORAN HILL 5158 SA
5950563	3251501	MAIN SOUTH ROAD OHALLORAN HILL 5158 SA
5972287	9590410	GRAVES STREET NEWTON 5074 SA
5972090	2526196	MEREDITH STREET NEWTON 5074 SA
37428254	9530747	HENLEY BEACH ROAD MILE END 5031 SA
47809995	2571431	RIVER ROAD NOARLUNGA DOWNS 5168 SA
45451363	7124619	TANUNDA ROAD NURIOOTPA 5355 SA
5962388	1904635	CHURCHILL ROAD KILBURN 5084 SA
5964139	9683641	CAVAN ROAD DRY CREEK 5094 SA
5958401	3277189	KETTERING ROAD ELIZABETH SOUTH 5112 SA
5960417	2180018	BAROSSA VALLEY WAY NURIOOTPA 5355 SA
5959685	8507075	MAIN NORTH ROAD SALISBURY PARK 5109 SA
5972402	1492915	GALLIPOLI GROVE REGENCY PARK 5010 SA
5954340	7308838	DAVID STREET PORT PIRIE 5540 SA
34662982	2250029	MURRAY BRIDGE DOWN STREAM RIVERLAND PIPELINE 9999 SA
5954348	1735154	FLORENCE STREET PORT PIRIE 5540 SA
5954523	4893253	ELLEN STREET PORT PIRIE 5540 SA
5953181	8379027	CAUSEWAY ROAD GLANVILLE 5015 SA
45228953	3102543	OLD MILL ROAD NURIOOTPA 5355 SA
5960421	7124619	TANUNDA ROAD NURIOOTPA 5355 SA
45451350	7124619	TANUNDA ROAD NURIOOTPA 5355 SA
5958997	6399077	COMMERCIAL ROAD ELIZABETH SOUTH 5112 SA
5961696	9496905	BRIDGE ROAD GULFVIEW HEIGHTS 5096 SA

Valve ID	USID	Address
5959371	6807272	YATALA VALE ROAD FAIRVIEW PARK 5126 SA
5959537	3361312	MERSEY ROAD OSBORNE 5017 SA
5955613	3747430	CHIEF STREET BROMPTON 5007 SA
5955645	4685214	THIRD STREET BOWDEN 5007 SA
5955649	3405536	DRAYTON STREET HINDMARSH 5007 SA
5961910	9696123	WYNN VALE DRIVE WYNN VALE 5127 SA
5959689	1486912	SAINTS ROAD SALISBURY PLAIN 5109 SA
5959304	5599011	GOLDEN GROVE ROAD GOLDEN GROVE 5125 SA
5958311	5284491	BOLIVAR ROAD BURTON 5110 SA
5960316	5962632	SMITH ROAD SALISBURY EAST 5109 SA
5961999	7117609	LANGHAM PLACE PORT ADELAIDE 5015 SA
5957724	9765843	WOMMA ROAD EDINBURGH NORTH 5113 SA
5951706	1193991	VICTORIA ROAD LARGS NORTH 5016 SA
5961082	3190198	BRIDGE ROAD POORAKA 5095 SA
5962659	1209853	OLD PORT ROAD ROYAL PARK 5014 SA
5962655	1209853	OLD PORT ROAD ROYAL PARK 5014 SA
5956438	3580464	NEWTON ROAD CAMPBELLTOWN 5074 SA
5956442	3580464	NEWTON ROAD CAMPBELLTOWN 5074 SA
5969816	3571194	BROUGHAM STREET MAGILL 5072 SA
5967975	8928398	CURTIS ROAD MUNNO PARA WEST 5115 SA
5967959	3439363	CURTIS ROAD SMITHFIELD PLAINS 5114 SA
5961561	4205172	GRAND JUNCTION ROAD WALKLEY HEIGHTS 5098 SA
5952634	1448389	TAPLEYS HILL ROAD SEATON 5023 SA
5952630	1448389	TAPLEYS HILL ROAD SEATON 5023 SA
5954931	2443794	WALKER AVENUE PARADISE 5075 SA
5955326	3580464	NEWTON ROAD CAMPBELLTOWN 5074 SA
5969823	4066510	THE PARADE KENSINGTON PARK 5068 SA
5956133	3334727	TUSMORE AVENUE TUSMORE 5065 SA
5960429	1798354	TOLLEY ROAD NURIOOTPA 5355 SA

Valve ID	USID	Address
5967979	3030472	COVENTRY ROAD MUNNO PARA 5115 SA
5967987	3030472	COVENTRY ROAD MUNNO PARA 5115 SA
5969776	7265872	INNES ROAD WINDSOR GARDENS 5087 SA
5956504	4084669	LEVELS ROAD POORAKA 5095 SA
5956508	4084669	LEVELS ROAD POORAKA 5095 SA
26311475	8746907	TAPLEYS HILL ROAD WEST BEACH 5024 SA
51865531	2841605	JAMES CONGDON DRIVE MILE END 5031 SA
5959275	5702570	GREENWITH ROAD GOLDEN GROVE 5125 SA
5951863	6340718	HARGRAVE STREET BIRKENHEAD 5015 SA
5962384	5478025	CROMWELL ROAD KILBURN 5084 SA
5969682	5478025	CROMWELL ROAD KILBURN 5084 SA
5959279	5702570	GREENWITH ROAD GOLDEN GROVE 5125 SA
5962410	1904635	CHURCHILL ROAD KILBURN 5084 SA
5958612	3277189	KETTERING ROAD ELIZABETH SOUTH 5112 SA
5958616	3277189	KETTERING ROAD ELIZABETH SOUTH 5112 SA
5964167	7464214	CHURCHILL-N ROAD DRY CREEK 5094 SA
5970462	3361312	MERSEY ROAD OSBORNE 5017 SA
5958298	9621298	DIMENT ROAD BURTON 5110 SA
5953084	5359610	JETTY ROAD LARGS BAY 5016 SA
5951977	5379775	CORMACK ROAD WINGFIELD 5013 SA
5951981	5379775	CORMACK ROAD WINGFIELD 5013 SA
5952041	9646200	MAY TERRACE OTTOWAY 5013 SA
5963130	9591048	EXETER TERRACE DUDLEY PARK 5008 SA
5965128	3183002	SECOND STREET BROMPTON 5007 SA
5951915	9367525	SOUTH ROAD WINGFIELD 5013 SA
5964209	7558916	CHURCHILL-N ROAD CAVAN 5094 SA
5945375	4851235	DYSON ROAD CHRISTIES BEACH 5165 SA
5945383	4851235	DYSON ROAD CHRISTIES BEACH 5165 SA
5944225	2341073	NEWLAND AVENUE MARINO 5049 SA

Valve ID	USID	Address
5944000	9151568	MORPHETT ROAD SEACOMBE GARDENS 5047 SA
5949484	2702506	MORPHETT ROAD GLENGOWRIE 5044 SA
5951229	6475960	MORPHETT ROAD NOVAR GARDENS 5040 SA
5964818	2109674	RICHMOND ROAD MARLESTON 5033 SA
5943958	7235506	STEPHENSON AVENUE SOUTH BRIGHTON 5048 SA
5944743	7219397	COLUMBIA CRESCENT HALLETT COVE 5158 SA
5944739	7219397	COLUMBIA CRESCENT HALLETT COVE 5158 SA
5950908	2859153	CHRISTINA STREET EDWARDSTOWN 5039 SA

ATTACHMENT C – Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the remediation of corrosion on critical isolation valves is not carried out (untreated risk), while the bottom panel sets out the residual risks if the remediation works are carried out (residual risk). Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Insignificant*	*Insignificant*	*Significant*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Negligible*	*Negligible*	*High*	*Low*	*Low*	*Moderate*	*Low*	***64***
		04	*04*	*20*	*08*	*08*	*14*	*08*	
Residual Risk	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Insignificant*	*Insignificant*	*Significant*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Negligible*	*Negligible*	*Moderate*	*Negligible*	*Negligible*	*Low*	*Negligible*	***30***
		01	*01*	*13*	*03*	*03*	*06*	*03*	

Priority		Priority Description
Priority 1	(red)	Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2	(orange)	Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3	(yellow)	Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4	(green)	Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA10

PROJECT REFERENCE	
Network	AGN – SA
Project No.	SA10
Project Name	Sleeved Railway Crossings
Budget Category	Capex
Risk and Priority	High, Priority 2
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Annabel Sandery, *Project Engineer* and Robin Gray, *Manager Systems Operations*
Reviewed By:	Robin Gray, *Manager Systems Operations*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	This project is a continuation of an existing program that was approved by the AER in the 2011-2016 Access Arrangement Review. It involves the inspection and repair of transmission pressure (TP) sleeved crossings within the network. Previous installation practices and third party activities within road and rail corridors have resulted in a number of instances of compromised cathodic protection on sleeved crossings. This has created the potential for premature failure of the steel transmission mains with associated risks to the public and reliability of supply. 81 TP sleeve crossing sites have previously been identified to be at risk, with 26 sites expected to be completed (assessed and remediated) during the current regulatory period. The remaining 55 sites will be assessed and remediated over the next regulatory period (11 per annum). The risk associated with these sleeved crossings has been assessed as high from an operational perspective (Priority 2).
Options Considered and Selected	Because this is a continuation of an existing program that has already been approved by the AER the options analysis that was originally carried out in the lead up to the last Access Arrangement has not been repeated. It is worth noting though that when the original analysis was carried out the inspection and repair option was found to be the only prudent option to address the risk of a major gas escape and the potential impact on safety and supply reliability was to excavate and physically inspect the sleeve crossings and remediate as required.
Estimated Cost	The forecast capital expenditure requirement for the inspection and repair program in the upcoming AA Period (AAP) is $2.183 million (real $2014/15).
Consistency with the NGR	This inspection and repair program complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because it is: • necessary to maintain and improve the safety of services and maintain the integrity of services (rules 79(2)(i) and (ii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue to provide a safe and reliable supply of natural gas to our customers. See Chapter 3 of the Access Arrangement Information (AAI) for further detail.

2 Background

A safety review by APA Network Engineering in 2009 identified steel mains contained within sleeved crossings as being at particular risk of corrosion due to the damp environment within the annular sleeve space, and the absence of electrical connectivity of the mains to the surrounding soil rendering cathodic protection ineffective. The review further found that in a number of locations vent pipes had been knocked over or removed by unknown third parties during modifications or alteration to the associated road and/or rail corridor. The absence of venting creates a confined space, which, in the event of a gas leak, could lead to a potentially explosive environment resulting in a risk to personnel, plant, equipment and public property in the immediate vicinity.

A premature failure of these mains as a result of corrosion will result in substantial cost and consumer disruption due to the complexity of the repair. It may also give rise to compensation claims if the failure results in personal injury or damage to property.

There are 292 locations within the network where sleeved and vented crossings have been used. However, the focus of this program of work is the 81 transmission pressure mains crossings (see Attachment B for site details).

The table below summarises the number of crossings by pipe material and pressure regime.

	Material			
Pressure Regime	**Steel**	**Cast Iron**	**Poly**	**Total**
Transmission	81	0	0	81
High	89	0	34	123
Medium	35	11	15	61
Low	7	8	12	27
Total	212	19	61	292

Sleeved crossings related to steel transmission mains are considered to pose the highest risk because these mains are the primary supply to the downstream distribution network and the volume of gas emanating from a leak at 1750kpa is significant. The likely repair strategy for a transmission leak has the potential to disrupt supply to a large number of consumers.

Over 80 per cent of the transmission network within the Adelaide metropolitan area has been in service for 25 years or more. There is a risk that mains in sleeved crossings in a damp and wet environment left “unprotected” due to ineffective corrosion protection could have significant coating disbandment and/or deterioration with undetected corrosion resulting in a major gas leak.

This risk was identified in the 2011-16 AAP and an allowance for the physical assessment and remediation of TP sleeve crossings included in the capital expenditure program that was approved by the AER.

Work on this inspection and repair project commenced in 2013. By the end of this regulatory period, 26 sites are expected to be completed leaving a further 55 sites to be completed in the next regulatory period (or 11 per annum).

At a number of sites the presence of underground water prevented the use of dry excavation techniques to expose the sleeves for inspection and welding to repair vent pipes. This problem has been overcome using civil contractors to excavate, secure the site and pump the water out while cutting and welding operations are undertaken. To date, despite the evidence of minor corrosion it has not been necessary to replace any of the TP mains encased within the sleeves.

The high pressure and medium pressure steel sleeved crossings are not considered to pose the same risk as transmission mains because of the lower pressure and the fewer number of consumers affected by a more localised failure. A number of these crossings are associated with smaller diameter mains servicing less than 100 consumers.

Although corrosion may not be an issue for cast iron mains contained within sleeves, there is a possibility of mains fracturing as result of differential soil movement concentrating stresses at the entrance and exit points. This risk associated with cast iron will be progressively eliminated as all the cast iron mains are scheduled to be replaced over the next AAP.

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to maintain our high levels safety and reliability. Consistent with the above insight, the assessment and repair of sleeved railway crossings will enable AGN to continue to provide a safe and reliable supply of natural gas to customers.

3 Risk Assessment

The key risk addressed by this assessment and remediation project is the risk of unexpected failure associated with corrosion of steel TP mains encased in a sleeve that results in a significant gas escape (and possible explosion) and adversely affects public safety and causes a major interruption to gas supply.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. Further detail on the risk assessment that has been carried out can be found in Attachment C. In short, the untreated risk associated with the sleeved railway crossings has been assessed as "High" given the risk associated with a major gas escape resulting in an interruption to supply, and has been assigned a Priority 2 rating.

4 Key Drivers and Assumptions

The key assumptions and drivers for this project are outlined below:

- Given the age of TP mains (over 25 years) there is potential for significant undetectable corrosion occurring within sleeved crossings.

- A resulting leak could pose a risk to public safety and the security of supply to a significant number of consumers.
- The integrity and life of the existing asset should be maintained by deferring replacement costs for as long as reasonably practicable.

This project is also consistent with AGN's operational theme of "Maintain" network safety. It specifically relates to the following insights:

- Customers value AGN's high reliability and want AGN to keep providing the same (as a minimum) service levels.
- Customers view gas as a reliable source of energy.

5 Options

As noted in Section 2, this is a continuation of a program of work approved for the current AAP. The options analysis that was originally carried out for this project ahead of the 2011-2016 Access Arrangement Review (see business case 18) has not therefore been repeated. It is worth noting though that the key finding from the original analysis was that the only prudent option to address the risk of a major gas escape and the potential impact on safety and supply reliability was to excavate and physically inspect the sleeve crossings and remediate as required.

It is also worth noting that if this project doesn't proceed and a failure occurs that results in a major supply loss, AGN will incur additional costs replacing the carrier pipe and relighting consumers. If the failure results in personal injury or damage to property, then AGN may also face compensation claims. Not addressing the corrosion can also be expected to reduce the useful lives of the assets. These costs are likely to be significant and not in the long-term interests of consumers, which is why the inspection and remediation option was taken.

6 Forecast Cost for the Upcoming AAP

The scope of this project involves excavating, exposing and physically inspecting the sleeve crossing at entry and exit points for moisture and/or corrosion and the repair or replacement of vent pipes. The work continues on an annual basis, avoiding work in winter periods when water-saturated ground is present.

To date the work has been carried out by a combination of internal pressure control, supervision and project management staff and contract resources (selected through a competitive tender process), for main laying, excavation and reinstatement. AGN intends to use the same approach over the next AAP. Based on previous experience the majority of the work is considered within the capacity of current main laying contractors. Additional civil contractors will be used to remove underground water and for retaining earth works.

The following table sets out the forecast capital expenditure for the next AAP, which assumes that 11 sites[1] are inspected and repaired each year. The costs in this table are based on the average cost of recently completed work carried out over the last five months, with the contractor rates based on the rates established through a competitive tender process. Given that inspections to-date have not identified the need to replace mains within sleeves, the cost estimates do not include any provision for sleeve replacement. If this is found to be necessary it will be funded separately. A more detailed cost breakdown is provided in Attachment A.

$'000 (Real 2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Materials	34.1	34.1	34.1	34.1	34.1	**170.5**
Labour	402.4	402.4	402.4	402.4	402.4	**2012**
Total	**436.5**	**436.5**	**436.5**	**436.5**	**436.5**	**2,183**

7 Consistency with National Gas Rules

Consistent with the requirements of rule 79 of the National Gas Rules, AGN considers that the capital expenditure is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services and to reduce the risk of incidents associated with major gas escapes and is of a nature that a prudent service provider would incur.
- *Efficient* – The work program is the only practical and effective option to efficiently address the risk. Engineering assessments and design will be carried out by internal staff and field work will be carried out by external contractors based on competitively tendered rates.
- *Consistent with accepted and good industry practice* – Good industry practice (AS 2885) dictates that identified risks be assessed and actioned to reduce (or eliminate) those risks in a manner that balances cost and risk. This project addresses an identified risk and has been developed based on a prudent approach balancing risk, expenditure and delivery. On this basis, the expenditure is consistent with accepted and good industry practice.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The proposed project is necessary to maintain the long term asset integrity, reducing the likelihood of premature failure. Failure to do so would incur additional Capex and/or Opex. It is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services.

The capital expenditure can therefore be viewed as being consistent with rule 79(1)(a) of the National Gas. The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

[1] This assumption is based on the following:

- it takes approximately three weeks to complete one site inspection and repair; and
- work is not carried out during winter.

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)).

ATTACHMENT A - Detailed Cost Breakdown

The table below provides a detailed breakdown of the forecast set out in Section 6.

$ (Real 2014/15 – excluding overheads)	
Item	**Unit Cost**
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
Total Unit Cost	39,680

11 crossings/year @ $39,680 = $436,480 /year

ATTACHMENT B – Transmission Sleeve Crossings Site Summary

System ID	Street	Suburb
9183658	GREY TCE	PORT PIRIE
9145142	SEMAPHORE RD	BIRKENHEAD
8379027	CAUSEWAY RD	GLANVILLE
7274932	PROMENADE	NEW PORT
3361312	MERSEY RD	OSBORNE
3361312	MERSEY RD	OSBORNE
3361312	MERSEY RD	OSBORNE
3361312	MERSEY RD	OSBORNE
9833801	MERSEY RD	TAPEROO
8994353	LIPSON ST	PORT ADELAIDE
9453414	THE COVE RD	HALLETT COVE
6032545	ROSETTA ST	ROSEWATER
6032545	ROSETTA ST	ROSEWATER
1448389	TAPLEYS HILL RD	SEATON
5027404	THE COVE RD	MARINO
5467815	FLORENCE TCE	ROSEWATER
9646200	MAY TCE	OTTOWAY
5379775	CORMACK RD	WINGFIELD
7597144	CROSS RD	PLYMPTON
5379775	CORMACK RD	WINGFIELD
5379775	CORMACK RD	WINGFIELD
2859153	CHRISTINA ST	EDWARDSTOWN
6930865	SOUTH TCE	WINGFIELD
4270937	MAGAZINE RD	WINGFIELD
4270937	MAGAZINE RD	WINGFIELD
7464214	CHURCHILL RD	DRY CREEK
7464214	CHURCHILL RD	DRY CREEK
7321879	HENSCHKE ST	DRY CREEK
7464214	CHURCHILL RD	DRY CREEK
7464214	CHURCHILL RD	DRY CREEK
1057649	MONTAGUE RD	POORAKA
7701234	DIMENT RD	SALISBURY NORTH
5164591	COMMERCIAL RD	EDINBURGH
6399077	COMMERCIAL RD	ELIZABETH SOUTH
3277189	KETTERING RD	ELIZABETH SOUTH
5838673	WINTERSLOW RD	ELIZABETH
8211458	PITTWATER DR	WINDSOR GARDENS
7124619	TANUNDA RD	NURIOOTPA
3299606	REFINERY RD	LONSDALE
4411443	NORTH ARM RD	WINGFIELD
9883944	TAPLEYS HILL RD	ROYAL PARK
5235164	TAPLEYS HILL RD	FULHAM GARDENS

1841557	HASLAM RD	SOLOMONTOWN
4893253	ELLEN ST	PORT PIRIE
9683641	CAVAN RD	DRY CREEK
3127005	GRAND JUNCTION RD	DRY CREEK
3127005	GRAND JUNCTION RD	DRY CREEK
5338028	VICTORIA RD	LARGS BAY
3334727	TUSMORE AVE	TUSMORE
6290373	GURR ST	PROSPECT
6082797	BIRDWOOD TCE	NORTH PLYMPTON
4598526	TUSMORE AVE	LEABROOK
4551166	ST BERNARDS RD	ROSTREVOR
2616860	ST BERNARDS RD	MAGILL
4643456	NEWTON RD	NEWTON

ATTACHMENT C – Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the inspection and repairs of TP pipelines is not carried out (untreated risk), while the bottom panel sets out the residual risks if the assessment and remediation works are carried out (residual risk). Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance	Financial Impact	Total Score of Risk Levels
Risk Untreated	Likelihood	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Medium*	*Minor*	*Significant*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Low*	*High*	*Low*	*Low*	*Moderate*	*Low*	*80*
		14	*08*	*20*	*08*	*08*	*14*	*08*	
Residual Risk	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Medium*	*Minor*	*Significant*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Low*	*Negligible*	*Moderate*	*Negligible*	*Negligible*	*Low*	*Negligible*	*35*
		06	*03*	*13*	*03*	*03*	*06*	*01*	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA14

PROJECT REFERENCE	
Network	AGN – SA Networks
Project No.	SA14
Project Name	Reactive Augmentation
Budget Category	Capex
Priority	3
Reference Docs	
Confidentiality Claim	No
PROJECT APPROVAL	
Prepared By:	Tom Bloch, *Project Engineer*
Reviewed By:	Chris Liew, *Integrity Manager*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 PROJECT OVERVIEW

This business case allows for a number of reactive network supply improvement projects throughout AGN's network over the regulatory period.

While there is an active program to forecast and resolve capacity constraints, a number of localised unforseen supply issues emerge each year that require a small mains extension and or additional regulator to maintain adequate capacity. These have typically been associated with the low pressure (LP) network cast iron networks where water ingress or local gas utilisation patterns have resulted in system pressures below minimum requirements.

Given the unpredictable nature of such capacity issues it is not possible to quantify the number or scope of individual reactive projects. It is however expected that the number of LP network capacity issues will reduce with replacement and pressure upgrade of the LP network over the next regulatory period.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Maintain theme as it maintains network reliability.

2 COST AND TIMING

It is not possible to predict the scope or timing of future "reactive" augmentation. For planning purposes it has been assumed that a notional allowance of $170k will be required for FY 2016/17 reducing to zero by the end of the regulatory period. This initial allowance has been based on the historic average of reactive augmentation over the 3 years of the current regulatory period (total cost of $0.5m).

The following table summarises costs over the next regulatory period. A cost breakdown of historic reactive augmentation projects has been provided in Attachment A.

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Minor Reactive Augmentation.	170	120	75	50	0	**415**

3 BACKGROUND

It is expected that there will be a number of "reactive" capacity constraint issues to be addressed on an annual basis over the next regulatory period. These capacity issues usually are a result of:

- General network load growth;
- Network ageing;
- The use of high demand appliances within low pressure networks; and
- Capacity restrictions as a result of water in main.

These supply issues are difficult to forecast accurately with the annual pressure survey program, with customer complaints generally triggering supply investigations. Invariably an additional interconnection, piecemeal replacement, supply regulator or a pressure upgrade will be required to increase local system pressures to levels consistent with maintaining a safe and reliable supply of gas to consumer premises.

Over the current regulatory period there have been 9 reactive augmentations carried out at a total cost of $497,400. Refer to Attachment B for details of historic projects and costs.

Typically "reactive" augmentation has been associated with low pressure cast iron network. As this network operates at a nominal 1.7 kPa there is very little tolerance to additional load from urban regeneration and to blockages caused by water. In particular, urban consolidation with customers choosing high instantaneous demand appliances creates "local" supply constraints that are generally rectified on a reactive basis.

An accelerated replacement of LP cast iron network commenced during this current regulatory period, with completion expected by the end of the next period. It is expected that this replacement program will gradually eliminate the requirement for future "reactive" augmentation projects.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for the recommended project are:

- Based on experience, there will be a number of "reactive" capacity constraint issues with the annual pressure survey program and customer complaints generally triggering supply investigations over the next regulatory period;
- There is a regulatory obligation to maintain safe and reliable supply of gas. Operating a gas network at low pressures creates the risk of gas outages and under some circumstances the potential for gas to build up inside of dwellings;
- It is not possible to forecast accurately in advance the scope and timing of reactive augmentation projects; and
- The number of reactive augmentation projects is expected to reduce progressively as the LP cast iron network is replaced.

5 RISK ASSESSMENT

Without augmentation, network pressures would be expected to fall below the recommended minimum pressures during the next regulatory period in a number of disparate sections of the Network. Operating a gas network at low pressures creates the risk of gas outages and under some circumstances the potential for gas to build up inside of dwellings. This would then present a significant risk to the public.

Failure to provide reactive augmentation of supply would risk localised gas interruption to up to 100 customers.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria.

The risk associated with not undertaking reactive augmentation in AGN's South Australian gas supply network has been assessed as "Moderate" and has been assigned Priority 3.

The risk assessment for this project is detailed in Attachment B.

6 OPTIONS

No alternative options are available to meet the objectives for this project.

Cost Benefit Analysis

There is no cost benefit applicable to this project.

Capex / Opex Trade-off

Substitution between operating and capital expenditure is not applicable in respect of this project.

7 JUSTIFICATION

Consistent with the requirements of Rule 79(1) (a) of the National Gas Rules, AGN considers that the capital and operating expenditure is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of existing services. Operating below recommended minimum pressures puts the reliable supply of gas at risk.
- *Efficient* – The cost estimates are based actual historical costs for similar works. While the exact scope cannot be defined at this stage, the most cost effective solution will be applied, with work awarded based on competitive tenders.
- *In accordance with good industry practices* – The need to provide supply augmentation, in response to customer complaints and as determined by pressure surveys, to meet existing service levels of supply to existing customers is a fundamental requirement for any gas network operator; and
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – Promptly responding and resolving localised gas supply issues will avoid customer outages and associated dissatisfaction, and perception that gas is an unreliable energy source. Failure to do so would encourage customers to move to other energy sources impacting on the long term sustainability of gas.

AGN therefore considers that the capital expenditure is justifiable under 79(1) (a) rule and rule 79(2)(c)(i) and (ii) of the National Gas Rules as the expenditure is necessary in order to maintain and improve the safety of services and maintain the integrity of existing services.

8 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken, AGN will be exposed to localised loss of supply to consumers and associated risks as outlined in Section 5.

ATTACHMENT A –Historic Cost

FY	Project Name	$'000
11/12	Imp Supply - Lanark Avenue	167
11/12	Imp Supply - Pennington	96.7
11/12	Imp Supply - Brooklyn Park	40.6
11/12	Imp Supply - Largs North	16
11/12	Imp Supply - West Beach	33.3
11/12	Imp Supply - Pasadena	33.2
11/12	Imp Supply - Athol Park	38.6
12/13	Imp Supply- Woodville Nth	22.6
13/14	Imp Supply- Croydon Park	49.4
	Total	**497.4**

ATTACHMENT B – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Occasional*	*N/A*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	
	Consequence	*Minor*	*N/A*	*Minor*	*Insignificant*	*Insignificant*	*Medium*	*Insignificant*	
	Risk Level	*Low*		*Low*	*Low*	*Low*	*Moderate*	*Low*	*59*
		10		*10*	*07*	*07*	*18*	*07*	
Residual Risk	**Likelihood**	*Unlikely*	*N/A*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
	Consequence	*Minor*	*N/A*	*Minor*	*Insignificant*	*Insignificant*	*Medium*	*Insignificant*	
	Risk Level	*Low*		*Low*	*Negligible*	*Negligible*	*Moderate*	*Negligible*	*28*
		05		*05*	*02*	*02*	*12*	*02*	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA15

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA15
Project Name	305 HP Seaford Aldinga Augmentation
Budget Category	Capex
Priority	3
Reference Docs	2015 South Australia Networks Asset Management Plan
Confidentiality Claim	Yes (Attachment B)
PROJECT APPROVAL	
Prepared By:	Vanessa Co, *SA Networks Asset Planning Manager*
Reviewed By:	Keith Lenghaus, *Victoria Networks Asset Planning Manager*
Approved By:	Jan Krzys, *Networks Asset Strategy and Planning Manager*

1 PROJECT OVERVIEW

Continued growth (greenfield and infill) in the southern suburbs of the Adelaide gas network is expected to reduce system pressures below the recommended minimum in the high pressure network (NW305) during the next regulatory period. This network supplies the Seaford Aldinga area.

To ensure the safe and reliable supply of gas to existing customers is maintained and adequate capacity is available for ongoing growth, it is planned to augment the network by:

- Looping the existing trunk main at Aldinga from Quinliven Road along How Road and Aldinga Beach Road with a DN 280mm PMT HP main; and

- Connecting to the existing HP trunk mains along Aldinga Beach Road.

Refer Attachment A for concept plans details.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Maintain theme as it maintains network reliability.

2 COST AND TIMING

Costs for this project have been based on recent similar projects that have undergone a competitive tendering process.

The following table provides a summary of forecast costs of the project. A detailed cost breakdown has been provided in Attachment B.

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Materials				197		197
Labour				1,139		1,139
Total				1,336		1,336

3 BACKGROUND

The southern suburbs south of Beach Road, Christies Beach to Aldinga continue to be one of the major residential growth areas of Adelaide.

The high pressure network in this area (from Noarlunga through Hackham, Huntfield Heights, Old Noarlunga, Seaford, Moana and down to Aldinga) supplies over 15,000 consumers.

Historically (over the last 5 years) customer connections have been growing, on average, at about 370 new residential connections per year. Based on Planning SA Development Plans, this level of growth is expected to continue for at least the next 10 years.

The following table summarises the historic growth over the past 5 years.

Historic Growth					
2009	2010	2011	2012	2013	5-Year Average
534	502	395	211	210	370

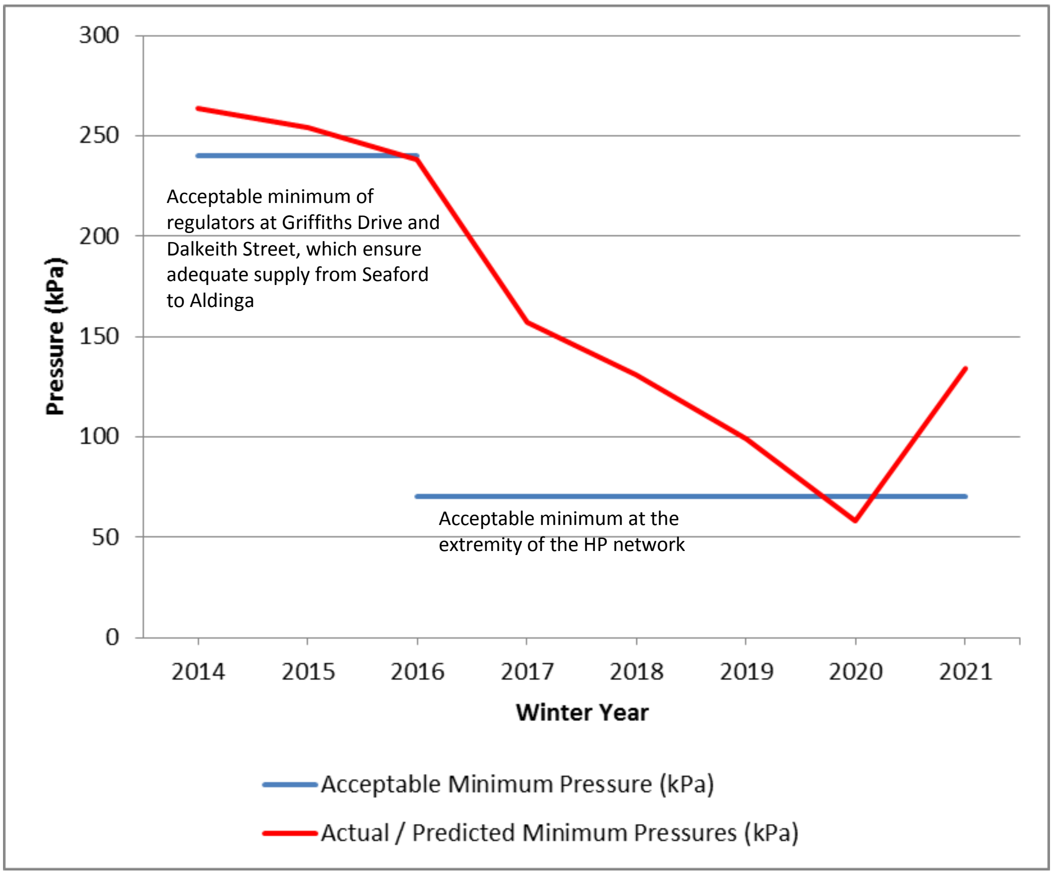
In addition to "organic" growth referred to above, a greenfield development requiring the extension of gas supply to McLaren Vale is underway during the current regulatory period. That development will be supplied via a trunk main extending from the existing HP trunk that supplies Aldinga (corner of Maslin Beach Road and Commercial Road, Maslin Beach). The extension to McLaren Vale is expected to be completed during FY 2015/16 with approximately 100 additional new connections per year expected going forward.

Market research has shown that there is further opportunity to extend gas supply to Sellicks Beach (approximately 5 km south of Aldinga) with potential for about 2,000 residential connections over the next 20 years. Extending supply to Sellicks Beach is limited by the current capacity of the HP trunk main supplying Aldinga.

Aldinga is located at the southern extremity of the high pressure network, and is approximately 15km from the nearest district regulator, with a single 100 mm diameter trunk main delivering gas to the area.

While forecast of extremity pressures is based on sound capacity analysis methodologies, due to the location and existing supply trunk main, a relatively minor increase in load at the southern extremity in Aldinga can rapidly draw down "spare" capacity within the network placing at risk the supply to over 2,000 residential consumers.

The following graph summarises the outcome of network modelling. Extremity pressures at Aldinga are expected to fall below the recommended 70 kPa by the 2020 winter.



The constraint in 2016 is related to minimum supply pressure to TP-HP regulators. This is being addressed through augmentation planned during FY 2015/16.

The constraint in 2020 is related to minimum end of main pressure to maintain supply to residential consumers. End of main pressure is expected to increase to about 140 kPa after augmentation, detailed in this business case, has been completed.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for the recommended project are:

- Organic growth of 370 new residential connections off the existing Noarlunga to Aldinga high pressure network;
- Trunk supply main to McLaren Vale completed by 2016;
- Greenfield growth of 100 new residential connections at McLaren Vale; and
- The impact of growth on network capacity has been assessed using network models validated to actual 2014 winter network pressures.

5 RISK ASSESSMENT

Operating a gas network at low pressures creates the risk of gas outages and under some circumstances the potential for gas to build up inside of dwellings.

From an operational perspective loss of supply of up to 1,000 customers would be at risk if the network is not augmented.

The development of the greenfield site at McLaren Vale would be at risk (due to inadequate gas supply), impacting future revenue potential, if the network is not augmented in line with forecasted growth.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria.

This project has been rated as "moderate" as per APA risk matrix (details in Attachment C) and has been assigned Priority 3.

6 OPTIONS

Two options were considered based on looping the existing trunk main. These are summarised in the following table.

Option	Description	Cost $'000	Useful Life Yrs	Risk Red'n Score	Cost Per Yr	Cost Per Unit Risk
Option 1	Loop trunk main at Aldinga with DN 280 PMT HP main from Quinliven Road along How Road and Aldinga Beach Road to tie into the existing 80SP HP trunk and tie into the existing 110 PMT HP trunk main along Aldinga Beach Road (2.0 km)	1,336	20+	59	66	23
Option 2	As per Option 1 with DN180 PMT trunk main	1,094	10	59	109	20

Cost Benefit Analysis

Of the two options only Option 1 has sufficient capacity to service an extension of gas to Sellicks Beach. With Option 2, future augmentation of the HP trunk main would be required (at a cost of about $1M) to extend supply to Sellicks Beach. This is considered likely within the next 5-10 years.

Based on the need to augment the network further in 5-10 years the net present cost (10% over 10 years) of Option 2 is $1,480k.

Option 1 is recommended as it represents the most cost effective long term solution.

Capex / Opex Trade-off

There is no opportunity to substitute Opex for Capex in this instance.

The additional mains do not materially impact current Opex.

7 JUSTIFICATION

Consistent with the requirements of Rule 79(1) (a) of the National Gas Rules, AGN considers that the capital and operating expenditure is:

- *Prudent* – The expenditure is necessary in order to improve the integrity of existing services. Operating below recommended minimum pressure puts the reliable supply of gas at risk.
- *Efficient* – The cost estimates for this project are based on actual costs for similar works that have been based on competitive tender rates for labour, materials and fittings. The recommended option represents the most cost effective long term solution as detailed in Section 6.
- *In Accordance with good industry practices* – Gas utilities across Australia are obligated to reduce risks within their networks to as low as reasonably practicable. Maintaining a safe and reliable supply of gas by maintaining adequate system pressures is consistent with this objective.
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – Proactively addressing future gas supply issues will also avoid potential long term revenue loss if gas is seen by the market as unreliable with consumers moving to electricity.

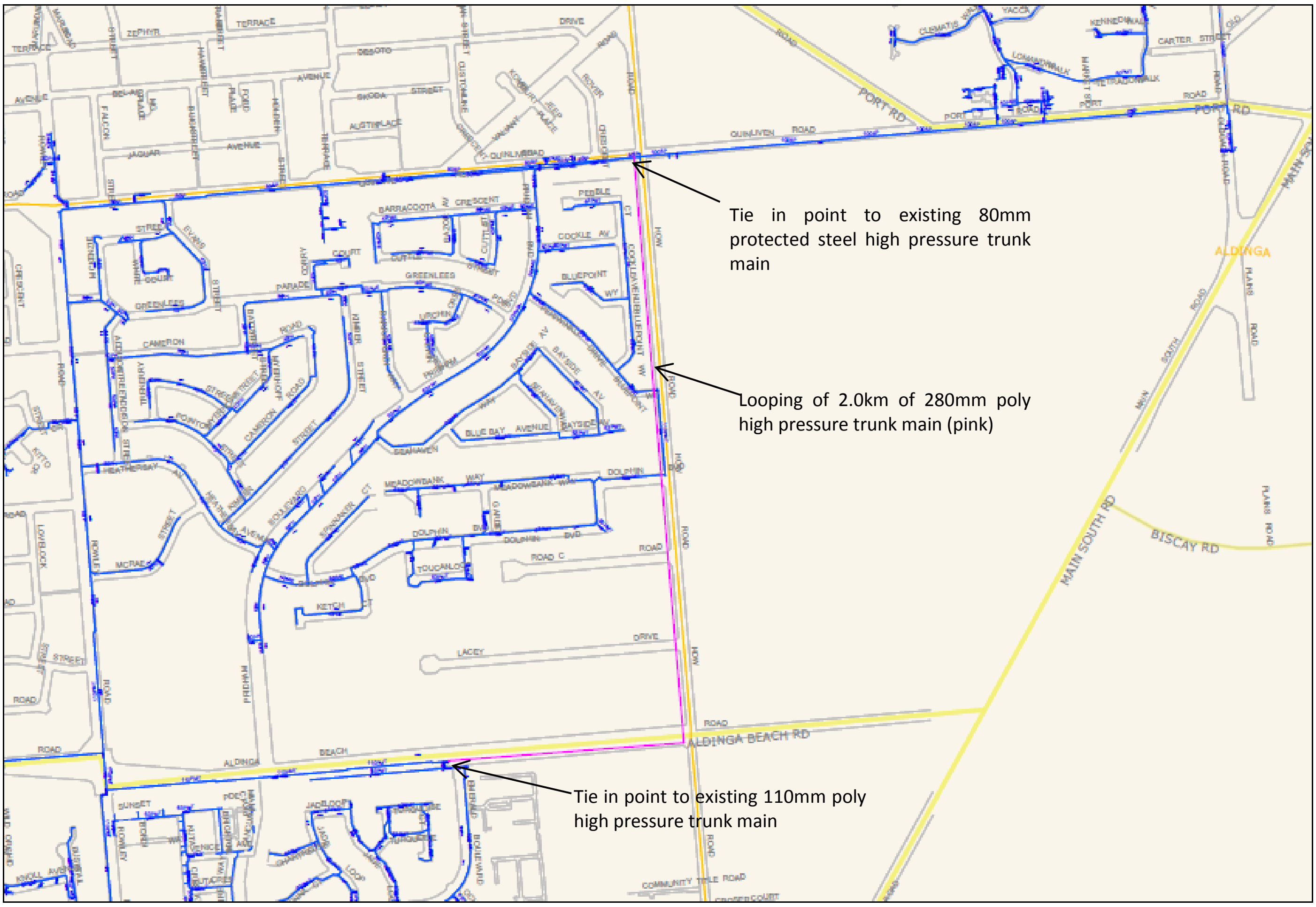
AGN therefore considers that the capital expenditure is justifiable under 79(1) (a) rule and rule 79(2)(c)(i) and (ii) of the National Gas Rules as the expenditure is necessary in order to maintain and improve the safety and integrity of existing services.

8 CONSEQUENCES OF NOT PROCEEDING

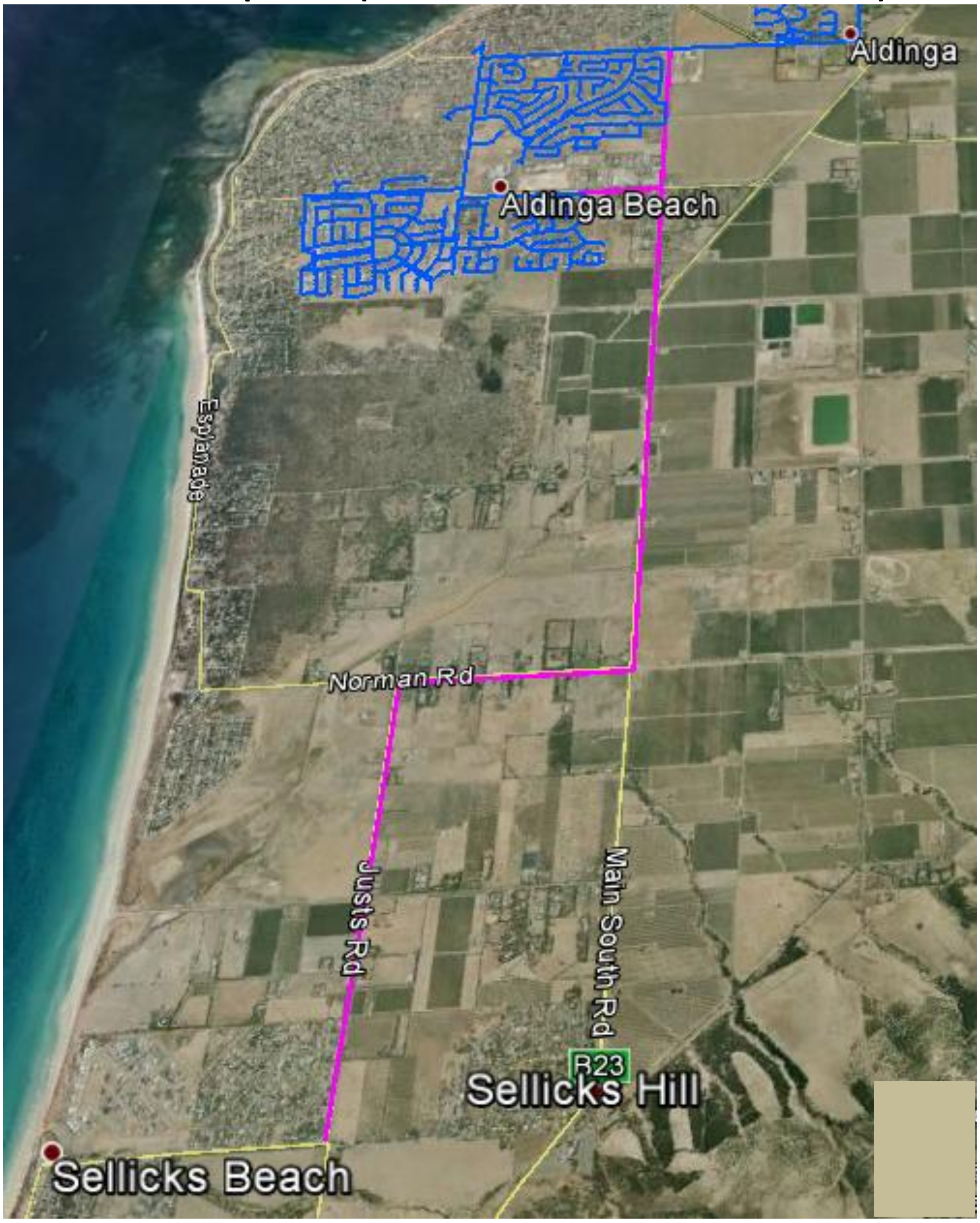
If this project is not undertaken, AGN will be exposed to consequences associated with insufficient network capacity. These include:

- Potential loss of supply to over 1,000 existing consumers; and
- Loss of reputation of gas as a reliable fuel.

Attachment A – Concept Plan (FY 19 - FY 20)



Attachment A – Concept Plan (Future Extension to Sellicks Beach)



ATTACHMENT B – Detailed Cost Breakdown

Option 1 (Recommended) Costs

[redacted]

Option 2 Costs

[redacted]

ATTACHMENT C – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	*Occasional*	*N/A*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	
	Consequence	*Minor*	*N/A*	*Medium*	*Medium*	*Medium*	*Medium*	*Insignificant*	
	Risk Level	*Low*	*N/A*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	*Low*	***89***
		10	*N/A*	*18*	*18*	*18*	*18*	*07*	
Residual Risk	Likelihood	*Rare*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Minor*	*N/A*	*Medium*	*Medium*	*Medium*	*Medium*	*Insignificant*	
	Risk Level	*Negligible*	*N/A*	*Low*	*Low*	*Low*	*Low*	*Negligible*	***30***
		03	*N/A*	*06*	*06*	*06*	*06*	*03*	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA17

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA17
Project Name	325 HP Virginia Augmentation
Budget Category	Capex
Priority	3
Reference Docs	
Confidentiality Claim	Yes (Attachment B)
PROJECT APPROVAL	
Prepared By:	Vanessa Co, *SA Networks Asset Planning Manager*
Reviewed By:	Keith Lenghaus, *Victoria Networks Asset Planning Manager*
Approved By:	Jan Krzys, *Networks Asset Strategy and Planning Manager*

1 PROJECT OVERVIEW

Continued growth in the locality of Virginia is expected to reduce system pressures in the high pressure gas distribution network in that area below the minimum requirement during the next regulatory period.

To ensure that safe and reliable supply of gas to existing customers can be maintained and adequate capacity available for ongoing growth, it is planned to augment the network by duplicating 1.4km of the existing DN100 high pressure trunk main in Park Road with a DN180 polyethylene trunk main.

Refer to concept plan Attachment A for details.

2 COST AND TIMING

Costs for this project have been based on similar types of projects that have been subject to a competitive tendering process.

The delivery of the project is planned prior to the 2019 winter, however, load growth will be monitored annually with actual timing coinciding with the need to improve network capacity.

The following table provides a summary of forecast costs of the project. A detailed cost breakdown has been provided in Attachment B.

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Materials			72			72
Labour			737			737
Total			809			809

3 BACKGROUND

The area around Virginia is now a key production centre of hydroponic fruit and vegetables. Maintaining a suitable growing temperature in glasshouses is energy intensive, and fruit and vegetable growers are substantial consumers of natural gas, with three large consumers in the area.

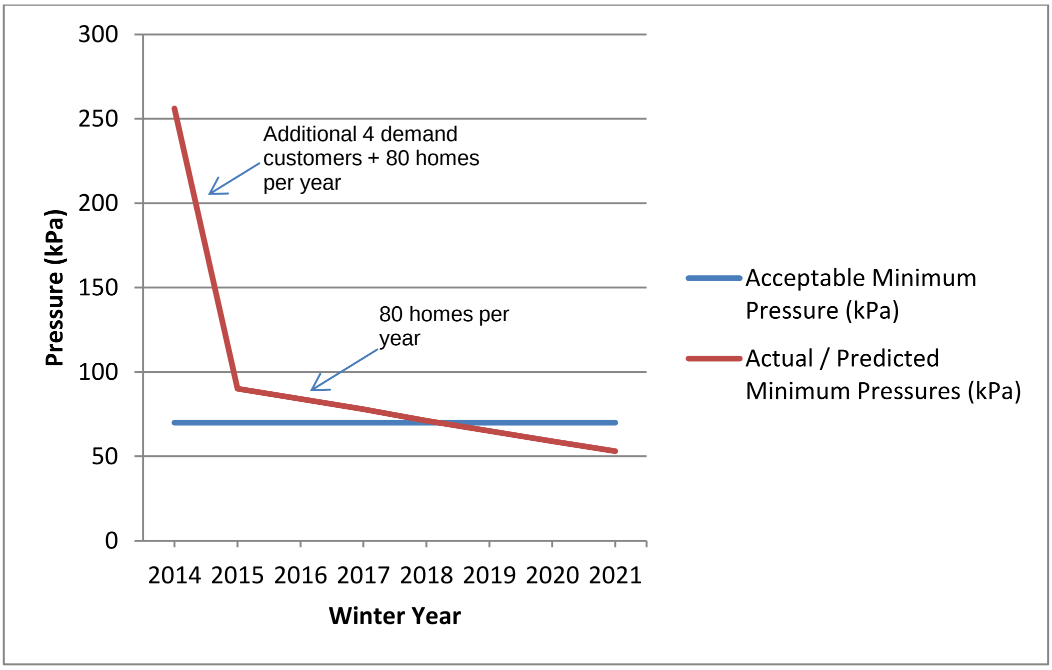
The existing gate station facility supplying Virginia has been at capacity over the last few years with a new gate station commissioned in early 2015. Due to previous limited capacity of the gate station it has not been possible to connect major new connections or load increases.

Four new enquiries for additional loads of the same order as existing Demand consumers have been received. These enquiries are expected to proceed over the next 2 years post completion of the upgrade to the Virginia gate station. Refer to Attachment A for location details of addition load enquiries.

Two of these enquiries are for connections located some distance from the gate station with the nearest supply of gas at the northern eastern and eastern extremity of the network. Due to the network configuration, network pressures are particularly sensitive to connections in these locations.

In addition to hydroponic fruit and vegetable development, residential growth is expected in Virginia South (80 houses per year) over the next 10 years with similar growth in Virginia North in the following 10 years.

The following diagram summarises the expected impact on system pressures based on forecast new loads.



Network augmentation is forecast to be required prior to the 2019 winter based on four additional Demand loads materialising from existing enquiries over the next two years.

The actual timing of augmentation is dependent on the timing, size and location of loads. The above analysis has been based on a moderate load assumption (based on two of the existing Demand consumers). Higher loads materialising in the eastern part of the network would necessitate augmentation earlier and could force further augmentation of the network by extending a trunk main along Penfield Road (looping the existing trunk network).

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for the project are:

- Completion of the Virginia gate station upgrade in early 2015;
- The addition gate station capacity will enable "pent up" hydroponic demand for gas in Virginia to be fulfilled;
- There is a high probability that four additional Demand customer loads will be required to be serviced over the next 2 years;
- Residential growth will develop as expected (80 new homes per year);
- Network pressure is expected to fall below the minimum level in 2019; and
- The impact of growth on network capacity has been assessed using network models validated to actual 2014 winter network pressures.

5 RISK ASSESSMENT

Operating a gas network at abnormally low pressures creates the risk of gas outages and under some circumstances the potential for gas to build up inside dwellings.

If the network is not augmented and gas pressures fall to low levels, supply to one or two Demand consumers and up to a 100 residential consumers can be affected.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria.

This project has been rated as "moderate" as per APA risk matrix (refer to Attachment C) and as such has been assigned a Priority 3.

6 OPTIONS

Two options were considered based on looping the existing trunk main. These are summarised in the following table.

Option	Description	Cost $'000	Useful Life Yrs	Risk Reduction Score	Cost $'000 Per Year	Cost $'000 Per Risk Reduction
Option 1	1.4 km DN180 HP PE trunk main extension – Park Road. - Refer to Attachment A for details.	809	20	40	40.5	20.2
Option 2	As above with 1.4 km DN100 steel TP main extension with a TP/HP Reg in vicinity of Park and Odgers Road. Refer to Attachment A for details.	2,485	25+	40	99.4	62.1

Cost Benefit Analysis

Option 1 supports the anticipated industrial and commercial load development in the area over the next regulatory period. At expected connection rates and loads it is projected that this option will provide sufficient capacity over the next 20 years (assuming only marginal residential growth each year).

If additional moderate to high loads materialise in the north east and east areas of the network, further augmentation will be required. It is envisaged this could be accommodated by looping the existing HP trunk network by extending the HP main down Penfield Road. There is no strong evidence at this stage that this will be required during the next regulatory period.

Option 2 provides slightly more capacity than Option 1 however it is not as cost effective.

Option 1 is therefore planned, based on lower cost per year and lower cost per risk reduction score.

Capex / Opex Trade-off

None applicable.

7 JUSTIFICATION

Consistent with the requirements of Rule 79(1) (a) of the National Gas Rules, AGNL considers that the capital expenditure is:

- *Prudent* – the expenditure is necessary in order to improve the integrity of existing services. Operating below minimum pressure puts the reliable supply of gas at risk.
- *Efficient* – the cost estimates for this project are based on costs for similar works that have been based on competitive tender rates for labour, materials and fittings. The recommended option represents the most cost effective long term solution as detailed in Section 6.
- *In accordance with good industry practices* – gas utilities across Australia aim to reduce risks with in their networks to as low as reasonably practicable. Maintaining a safe and reliable supply of gas by maintaining adequate system pressures is consistent with this objective.
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – proactively addressing future gas supply issues avoids the risk of outages, safety issues and associated costly reactive measures. Planned augmentation is therefore consistent with achieving the lowest sustainable cost.

AGN therefore considers that the capital expenditure is justifiable under 79(1) (a) rule and rule 79(2)(c)(i) and (ii) of the National Gas Rules as the expenditure is necessary in order to maintain and improve the safety of services and maintain the integrity of existing services, which AGN interprets to include the security of supply of its services.

8 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken then AGN will not be able to connect new consumers or enable existing consumers to increase gas load, and ultimately lead to restriction of gas supply to existing consumers.

Attachment A – Concept Plan

ATTACHMENT B – Detailed Cost Breakdown

Option 1 Costs

[redacted]

Option 2 Costs

[redacted]

ATTACHMENT C – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Possible*	*N/A*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Minor*	*N/A*	*Medium*	*Medium*	*Minot*	*Medium*	*Insignificant*	
	Risk Level	*Low*	*N/A*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	*Negligible*	***68***
		08	*N/A*	*14*	*14*	*14*	*14*	*04*	
Residual Risk	**Likelihood**	*Rare*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Minor*	*N/A*	*Medium*	*Medium*	*Medium*	*Medium*	*Insignificant*	
	Risk Level	*Negligible*	*N/A*	*Low*	*Low*	*Low*	*Low*	*Negligible*	***28***
		03	*N/A*	*06*	*06*	*06*	*06*	*01*	

Priority		**Priority Description**
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA19

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA19
Project Name	Upgrade TP regulator stations without OPSO valves
Budget Category	Capex
Priority	2
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Chris Liew, *Integrity Manager*
Reviewed By:	Dominic Zappia, *Manager Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 PROJECT OVERVIEW

The scope of this project is to install an over-pressure shut-off (OPSO) system at 45 transmission pressure (TP) regulator stations within the distribution network, and replace obsolete Grove regulators at 29 of these stations.

The installation of OPSO devices will protect the network downstream of a regulator station from over-pressurisation in the event of its failure.

The existing Grove regulators at these stations are over 40 years old and neither spares nor direct replacement units are now available.

The replacement program will require installation of regulator bypasses at 21 of the 45 stations to maintain gas supply in the downstream network.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Improve theme as it improves network safety.

2 COST AND TIMING

Costs have been spread out over five years commensurate with risk and resources. The cost has been based on actual costs for recent similar work.

A summary of Capex costs is provided in the table below. A detailed cost breakdown has been included in Attachment A.

$000's (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
OPSO Replacement	79.7	79.7	79.7	79.7	79.5	**398**
Grove Regulator Replacement	188.5	125.6	125.6	209.4	83.8	**733**
Bypass Installation	180	180	60	0.0	0.0	**420**
Total	**448**	**385**	**265**	**289**	**163**	**1,551**

3 BACKGROUND

Transmission pressure (TP) regulators (of which there are 89) form the primary supply to over 410,000 consumers in the network. They vary in age up to 45 years, and over that time various configurations have been used.

The current TP regulator design standard includes dual regulator streams, each with an active monitor arrangement, Over-Pressure Shut-Off (OPSO) valves, and telemetry. This system provides a multi-layer protection against over-pressurisation of the downstream network.

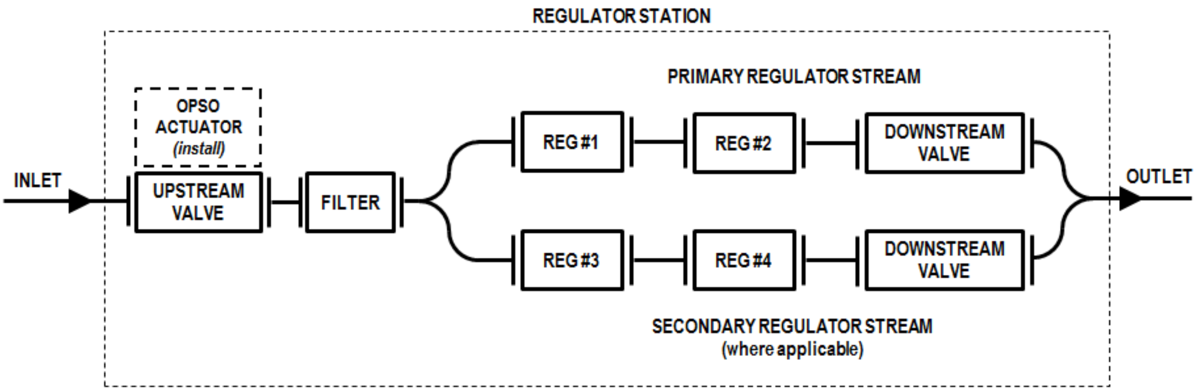
OPSO devices are fitted upstream of regulator runs and are designed to automatically close the upstream valve on high outlet pressure should a regulator stream fail. They are also designed to be quick acting to prevent over-pressurisation of the downstream network. Essentially an OPSO system is the last line of defence against over-pressurisation of the downstream network.

An engineering review of the existing TP regulators has highlighted that 45 stations (Refer to Table 2 Attachment A) do not have an OPSO system, with potential for over pressuring the downstream networks.

There have been several instances where the active regulator rubber flow control sleeve has been eroded by dust with the regulator failing open. This same dust erosive action could conceivably render the downstream sleeve of the monitor regulator inoperable, with both regulators effectively failing open. While telemetry provides an alert that a problem exists, maintenance response may not be quick enough to avert an overpressure incident. In this instance the only failsafe method is to rely on an OPSO or full flow relief valve. The latter is not used within AGN's networks because of safety issues associated with venting.

Exposing the downstream networks (MAOP of 140 -420 kPa) to TP pressure (nominally 1650 kPa) would cause physical damage to the piping as well as major gas escapes from failed joints and venting regulators.

The diagram below shows a generic schematic of a TP regulator station in SA Networks.



It is proposed to retro fit a new upstream valve and OPSO mechanism to provide positive overpressure protection at the identified stations. OPSO actuators currently available on the market do not fit the existing old-style Audco upstream valve, necessitating its replacement.

Twenty one of the 45 regulator stations cannot be taken off line without causing a supply interruption in the downstream networks affecting thousands of consumers. In these cases, a bypass must be installed prior to isolation and blowdown of the regulator station, before the OPSO system can be installed (refer to Table 2 Attachment A for sites where this will be required).

Twenty nine of the 45 regulator stations utilise old (35-45 years) Grove regulators, which are no longer supported by their manufacturer (refer to Table 2 Attachment A). Spare parts and replacement regulators are no longer available on the market. It is therefore planned to replace these regulators at the same time as fitting the OPSO valve.

It is planned to upgrade 45 existing regulator stations (refer Attachment A for details) over the next regulatory period, with the following scope of work:

- Install bypass where required (21 regulator stations);
- Isolate and blowdown regulator station (45 regulator stations);
- Replace the regulator upstream valve and install OPSO actuator (45 regulator stations);
- Replace pipe spool to fit the new valve;
- Replace 70 Grove regulators (29 regulator stations with 35 streams x 2 regulators per stream); and
- Install pressure sensing lines for OPSO actuator and new regulators.

4 *KEY DRIVERS & ASSUMPTIONS*

The key drivers for the recommended project are:

- 45 TP regulator stations in SA Networks do not have an OPSO system fitted, resulting in potential for over pressuring downstream networks.
- 29 of these stations utilise old obsolete Grove regulators, for which spares and replacements are no longer available; and
- Bypass pipework is required at 21 sites.

5 RISK ASSESSMENT

In event of an overpressure situation there is potential for:

- Over pressure at consumers' premises causing a major gas release, resulting in a fire/explosion causing injuries and/or property damage.
- Damage to downstream networks requiring significant replacement of mains, services, meters and service regulators.
- The potential loss of supply to several thousand consumers while repairs are carried out.
- Major reputational damage to AGN.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria.

The untreated risk associated with this project has been assessed as "High" and as such has been assigned Priority 2. Refer to the risk assessment matrix in Attachment B.

6 OPTIONS

Two options were considered:

Option 1 - Install OPSO system and concurrently replace obsolete Grove regulators. Cost $1,551k.

Option 2 - Install OPSO system and reactive replacement of obsolete Grove regulators. When a Grove regulator fails, install a bypass (where required), blowdown the station, replace the regulator and fabricate new pressure sensing lines on site. Initial Cost $808k (OPSO) + $1,152k reactive replacement of Grove regulators (cost of regulator replacement + by pass).

Cost Benefit Analysis

Option 1 is chosen as it is the lowest risk solution (as it avoids additional bypass installations) and represents the lowest long term cost ($1,551k versus $1,961k)

Capex / Opex Trade-off

There is no material impact on Opex as result of this project. The additional OPSO facilities will be maintained as part of the existing preventative maintenance regime for each station.

Additional maintenance (increased inspections) in lieu of Capex would not be effective in managing the risk given the unpredictability of when and where failures, leading to overpressure, may occur.

7 JUSTIFICATION

Consistent with the requirements of Rule 79 of the National Gas Rules (NGR), AGN considers that the capital expenditure being sought for this project is:

- *Prudent* – the expenditure is necessary in order to improve the safety and security of gas services.
- *Efficient* – The recommended option solution represents the lowest cost solution as detailed in Section 6.

- *Consistent with accepted and good industry practice* – it is consistent with good industry practice to identify risks and take action to address those risks, and to ensure that assets undergo refurbishment when required to extend asset life.
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – The proposed project is necessary to maintain the asset reliability. Without the reliable shut off system there is potential liability for extended damage due to over pressurisation and gas leakage.

AGN therefore considers that the capital expenditure is justifiable under rule 79(1)(a) and rule 79(2)(c)(i) and (ii) of the National Gas Rules as the expenditure is necessary in order to; maintain and improve the safety of services, and maintain the integrity of existing services, which AGN interprets to include the security of supply of its services.

8 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken, then AGN will be exposed to risk of network overpressure that could have significant impact on the safety and reliability of the downstream network.

ATTACHMENT A – Detailed Cost Breakdown

Table 1- Unit Costs

Item No.	Item	Unit Cost $	Units	Total $'000
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
34	**Total**			
35	Materials			800.8
36	Labour			750.4
37	**Grand Total**			1,551

Table 2 - Regulator Station Details & Timing for Replacement

Regulator Station	Bypass required	OPSO	No. of Regulator streams	No. of Grove Regulators	FY
R106	1	1	1	2	16/17
R108	1	1	1	2	16/17
R125	1	1	1	2	16/17
R137	1	1	1	2	16/17
R132	1	1	1	2	16/17
R408	1	1	1	2	16/17
R413	1	1	1	2	16/17
R910	1	1	1	2	16/17
R912	1	1	1	2	16/17
R130	1	1	2	4	17/18
R135	1	1	2	4	17/18
R324	1	1	2	4	17/18
R105	1	1	0	0	17/18
R139	1	1	0	0	17/18
R119	1	1	0	0	17/18
R140	1	1	0	0	17/18
R141	1	1	0	0	17/18
R213	1	1	0	0	17/18
R411	1	1	0	0	18/19
R414	1	1	0	0	18/19
R911	1	1	0	0	18/19
R321	0	1	1	2	18/19
R110	0	1	1	2	18/19
R118	0	1	1	2	18/19
R127	0	1	1	2	18/19
R133	0	1	1	2	18/19
R136	0	1	1	2	18/19
R138	0	1	1	2	19/20
R211	0	1	1	2	19/20
R221	0	1	1	2	19/20
R310	0	1	1	2	19/20
R315	0	1	1	2	19/20
R318	0	1	1	2	19/20
R326	0	1	1	2	19/20
R406	0	1	1	2	19/20
R107	0	1	2	4	19/20
R131	0	1	2	4	20/21
R216	0	1	2	4	20/21
R143	0	1	0	0	20/21
R144	0	1	0	0	20/21
R331	0	1	0	0	20/21
R215	0	1	0	0	20/21
R329	0	1	0	0	20/21
R202	0	1	0	0	20/21
R210	0	1	0	0	20/21
Total	21	45	35	70	

Table 3- Units & Cost Summary

		Units						Cost $'000 (Real 2014/15)					
Item	Unit Cost $’000	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total Units	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total Cost
OPSO Replacement	8.9	9	9	9	9	9	45	79.7	79.7	79.7	79.7	79.7	398.3
Regulator Replacement	10.5	18	12	12	20	8	70	188.5	125.6	125.6	209.4	83.8	732.9
By- Pass	20.0	9	9	3	0	0	21	180.0	180.0	60.0	0.0	0.0	420.0
Total								448.1	385.3	265.3	289.1	163.4	1,551

ATTACHMENT B – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
	Consequence	*Major*	*Minor*	*Significant*	*Significant*	*Medium*	*Significant*	*Significant*	
	Risk Level	*High*	*Low*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	***98***
		21	*05*	*15*	*15*	*12*	*15*	*15*	
Residual Risk	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Major*	*Minor*	*Significant*	*Significant*	*Medium*	*Significant*	*Significant*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Low*	*Moderate*	*Moderate*	***77***
		16	*03*	*13*	*13*	*06*	*13*	*13*	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA21

PROJECT REFERENCE	
Network	AGN– SA
Project No.	SA21
Project Name	Replacement of TP Pipelines M21 and M53
Budget Category	Capex
Risk and Priority	High, Priority 2
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachment B)
PROJECT APPROVAL	
Prepared By:	Mujibur Rahman, *Corrosion Engineer*
Reviewed By:	Chris Liew, *Integrity Manager*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	• Transmission Pressure (TP) Pipelines M21 and M53 (steel mains within the Adelaide Distribution system) are at the end of their useful lives with significant corrosion having been identified beneath the heat shrink sleeves (HSS) at welded joints in these two pipelines. The presence of this corrosion means there is a significant risk of a major gas escape that could affect the safety and reliability of supply to 20,000 customers located in Adelaide's southern suburbs. • A section of the concrete covering pipeline M53 at Christies Creek crossing near Marrow Road has also recently been washed away, which has left this section of the pipeline exposed to a major gas escape that could adversely affect the safety and reliability of supply. The untreated risks associated with these two pipelines have been rated as High (Priority 2).
Options Considered	Three options were considered to address the risks outlined above: • Option 1: Do nothing, which would leave the network exposed to the risk of a major gas release that causes personal injuries and/or property damage and the potential loss of supply to 20,000 consumers in Adelaide's southern suburbs. • Option 2: Remediate the corrosion at HSS joints and relay the pipeline at Christies creek, which would reduce the likelihood of a major gas release but not to the same extent as Option 3. • Option 3: Replace both pipelines, which would reduce the risk of a major gas release to as low as reasonably practicable.
Option Selected	Option 3 was selected because it is the most cost effective long term option and provides significantly better risk reduction at a lower cost than the other two options. Implementing this option will reduce the risk to as low as reasonably practicable and in a manner that balances cost and risk, consistent with Australian Standard AS2885 (Pipelines – Gas and liquid petroleum pipelines). Work on this project is expected to commence in FY16/17 and be completed in FY17/18.
Estimated Cost	The forecast capital expenditure for the replacement program in the next Access Arrangement Period (AAP) is $7.468 million (real $2014/15).
Consistency with the NGR	The replacement of these assets complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because it is: • necessary to maintain and improve the safety of services and maintain the integrity of services (rules 79(2)(i) and (ii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (rule 79(1)(a)).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue to provide a safe and reliable supply of natural gas to our customers. More information on our stakeholder engagement program and results is provided in Chapter 3 of the Access Arrangement Information (AAI).

2 Background

AGN’s SA gas distribution network has approximately 130 km of TP steel mains that were laid primarily in the 1970s and 1980s when the practice was to use heat shrink sleeves (HSS) over the field-welded joints for corrosion protection. Dis-bonding of the HSS can result in pitting corrosion of the steel under the sleeves. Corrosion occurs when the protective coating has dis-bonded and water has entered through a small coating defect. As the corrosion occurs beneath the surrounding coating, the effectiveness of the cathodic protection system is limited.

Transmission pipelines M21 (DN200, 1.1km) and M53 (DN200, 4.06 km) from Pt Stanvac to Noarlunga are about 45 years old, which is the end of their respective useful lives. The pipes have been externally protected by a tar epoxy coating with HSS used over the field joints. These pipelines form a single feed to over 20,000 consumers in the southern suburbs of Adelaide.

Recent excavations of 20 joints along these pipelines have revealed dis-bonding of the HSS at all the joints and substantial corrosion scattered over the pipe surface. The corrosion was mostly found to be in the form of tunnelling pit corrosion, varying in depth up to 2.4mm, representing 38% of the pipe wall thickness.

An example of the excavation findings are shown in the photos below.

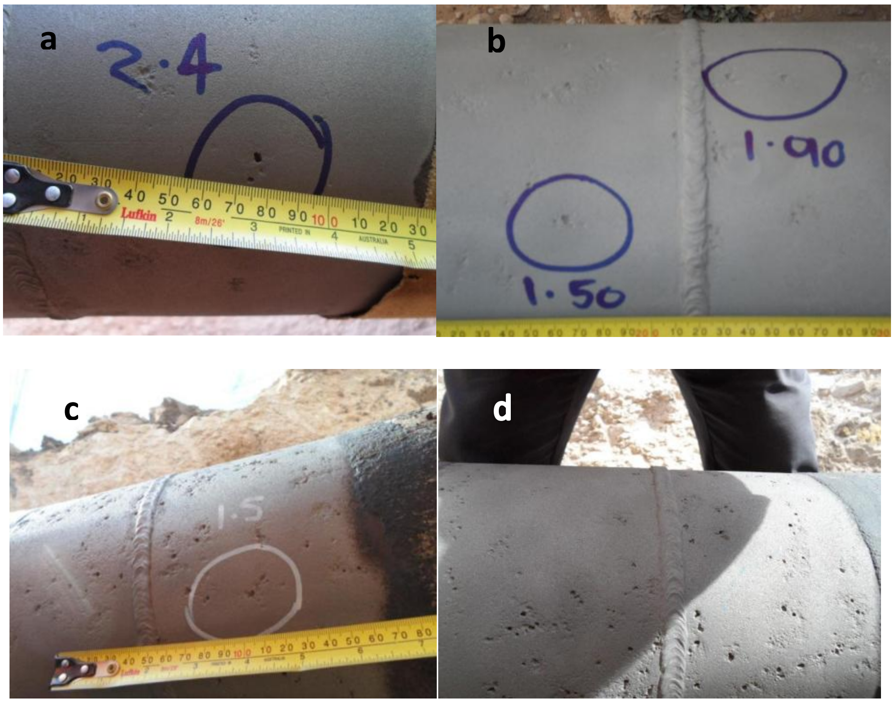


Figure: Photos taken from HSS excavation sites of M21 and M53 pipelines

Deep tunnelling pits (photos 'a' and 'b') were scattered ('c' and 'd') over the pipe surface.

Based on these excavations it is expected that all of the HSS on M21 and M53 pipelines will have the same or similar corrosion issues. It is estimated that there are 470 weld joints along the M21 and M53 pipelines (based on 1 weld joint every 12 metres of piping, plus 10% for bends, etc). Without remediating these locations there is a significant risk that a “pinhole” failure will occur at one of these sites with the passage of time. As the operating pressure of these mains is relatively low, a burst rupture is highly unlikely, but it could result in a major gas release and jet fire that causes personal injuries and/or property damage.

Carrying out emergency repairs on these pipelines can be complex and present a safety risk to field personnel and the public given the operating pressure. Repairing the pipelines will also affect consumers if they have to be shut down. A typical repair would require a reduction in pipeline pressure, hot tap and stopple with bypass. Should these sections of main have to be shut down for emergency repair, the supply to over 20,000 consumers could be affected. Assuming a safe turn on and turn off cost of $50-$100 per customer, the cost of managing the safe turn off and turn on of this number of consumers supply range from $1-$2 million.

Following an assessment of the pitting corrosion issue, it was determined that replacement of the pipeline sections (either by replacing the entire pipelines or remediating the carrion at the HSS joints) was the only feasible permanent solution to remove the associated risk. While the risk from a potential leak exists, it is not deemed an immediate threat that requires immediate action, but good asset management requires that these assets be scheduled for replacement within the next 3-5 years, with regular monitoring in the interim.

In addition to the risks outlined above, pipeline M53 is exposed to a further risk. In 2008 the M53 pipeline was exposed at the Christies Creek crossing near Marrow Road because of flooding. Remedial works were undertaken at the time and a concrete slab was installed to cover and protect the pipe. Recently a section of the concrete (1.5m long by 1.5m wide) has been washed away allowing water to flow under the remaining concrete and erode the soil beneath it. The only long term permanent solution to protect the pipe and avoid a major gas escape is to re-lay this section of pipe deep below the surface of the creek bed.

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to maintain our high levels safety and reliability. Consistent with the above insight, the replacement of TP Pipelines M21 and M53 will enable AGN to continue to provide a safe and reliable supply of natural gas to customers.

3 Risk Assessment

The key risks associated with corrosion of the pipeline welded joints on M21 and M53 and the exposure of pipeline M53 at Christies Creek are:

- a major gas release resulting in a jet fire that causes personal injuries and/or property damage; and
- the potential loss of supply to 20,000 consumers in Adelaide's southern suburbs should either the M21 or M53 pipelines have to be isolated for emergency repairs.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. Further detail on the risk assessment that has been carried out can be found in Attachment C. In short, the untreated risk associated with the corrosion has been assessed as "High" given the risk associated with the loss of supply to over 20,000 consumers and as such has been assigned a Priority 2 rating.

4 Key Drivers and Assumptions

The key drivers and assumptions for this project are as follows:

- Significant corrosion is present at all field joints on pipelines M21 and M53.
- Corrosion at field joints is likely to lead to significant gas escapes, impacting the safety of the public, emergency response personnel as well as the reliability of supply to over 20,000 consumers in Adelaide’s southern suburbs.
- The pipeline crossing at Christies Creek at Morrow Road needs to be re-laid to a greater depth to prevent damage from water erosion.

This project is also consistent with AGN’s operational theme of “Maintain” network safety. It specifically relates to the following insights:

- Customers value AGN’s high reliability and want AGN to keep providing the same (as a minimum) service levels.
- Customers view gas as a reliable source of energy.

5 Options

Three options have been identified to deal with the risks of major gas escapes from M21 and M53 pipelines:

- Option 1 – Do nothing.
- Option 2 - Remediate corrosion at HSS joints and relay the pipeline at Christies Creek.
- Option 3 - Replace both pipelines at a cost $7.47 million.

The costs and benefits associated with these three options are summarised in the table below. As this table highlights, Option 1 will do nothing to reduce the risk to human health and safety and the safety and reliability of services associated with a major gas escape and is not therefore considered a viable option. In contrast to Option 1, options 2 and 3 will both reduce the likelihood of a major gas escape but the extent to which they do so differs because under Option 2 there is still potential for corrosion activity associated with dis-bonding of the 45 year old tar epoxy coating to result in a major leak within the next 25 years. Option 3, on the other hand, will result in a greater reduction in risk than Option 2 but does so at a higher cost ($7.47 million vs $4.98 million – see Attachment B for more detail on these cost estimates).

Costs and benefits of the options

Item	Option 1 Do Nothing	Option 2 Remediate corrosion and relay pipeline at Christies Creek	Option 3 Replace both pipelines
Costs/Risks	Risk of a major gas escape that adversely affects: ▪ human health and safety and property and gives rise to compensation claims; and ▪ the safety and reliability of supply to 20,000 consumers in Adelaide's southern suburbs if repairs are required, which will give rise to repair costs and the cost of customer relighting ($1-$2 million).	$4.98 million (real $2014/15) Risk that even with the remediation works corrosion activity will continue as the tar epoxy coating over the remainder of the pipeline deteriorates. There is therefore still a risk of a major gas escape under this option within the next 25 years that could adversely affect: ▪ human health and safety and property and gives rise to compensation claims; and/or ▪ the safety and reliability of supply to 20,000 consumers in Adelaide's southern suburbs if either the M21 or M53 pipelines have to be isolated for emergency repairs. Note risks are lower than under Option 1.	$7.47milion (real $2014/15)
Benefits	No upfront costs to replace the pipeline.	Reduces the likelihood of a major gas escape and AGN's exposure to compensation claims and the costs associated with carrying out emergency repairs and customer relight, but by a lesser extent than Option 3.	Reducing the risk of a major gas escape to as low as reasonably practicable and therefore significantly reducing AGN's exposure to compensation claims and the costs associated with carrying out emergency repairs and customer relights.

Given the difference in costs, benefits and risks under options 2 and 3, further analysis was carried out to calculate both:

- The cost of reducing the level of risk under the two options, which was calculated by dividing the cost of the option by the reduction in the risk score achieved under the relevant option. The risk scores are set out in Attachment C and have been calculated by taking the difference between:
  - the risk score that has been calculated assuming the pipelines remain in place and untreated (risk score: 118); and
  - the residual risk scores that have been calculated assuming the remedial actions identified under the options are carried out (Option 2 residual risk score: 88 and Option 3 residual risk score: 44).
- The cost on per year of remaining asset life basis, which was calculated by dividing the cost of the option by the remaining life of the assets under the relevant option. The asset life for a new transmission pipeline (Option 3) protected from corrosion by a protective coating and impressed current cathodic protection system is expected to be 80 years. Using the expected 80 year life

for a pipeline suitably protected, a residual life of 35 years has been assumed for the existing pipelines that are 45 years old (Option 2).

The results of this analysis are summarised in the table below.

Risk adjusted analysis

	Cost $M	Risk Reduction Score	Asset Life Years	$'000 Per Risk Reduction Score	$'000 Per Year of Remaining Asset Life
	(a)	(b)	(c)	(d)=(a)/(b)*1000	(e)=(a)/(c)*1000
Option 2	$4.98	30	35	166	142
Option 3	$7.47	74	80	101	93

As the last two of these columns reveal, Option 3 is the most cost effective long term option (ie, the costs of this option are lower on a per year of remaining asset life basis) and provides significantly better risk reduction at a lower cost (ie, the costs of this option are lower on a per risk reduction score measure). Option 3 has therefore been selected.

6 Forecast Cost for the Upcoming AAP

The table below provides a summary of the capital expenditure that is forecast to be incurred in the next AAP period under Option 3. The forecast has been developed using the following assumptions:

- A front end engineering design (FEED) study will need to be carried out in FY16/17 financial year, which will involve a detailed assessment of the route and development of a design specification from which tenders can be prepared and long lead items procured. This work will be carried out internally. Construction and commissioning is planned to be completed in the following year (FY17/18) and will be carried out by contractors engaged through a competitive tender process.
- The FEED study costs are based on internal labour rates, while the materials and labour costs for the construction and commissioning phase are based on a similar TP pipeline replacement project that was recently the subject of a competitive tender (ie, the Greenhill Road replacement in 2012).

A more detailed cost breakdown is provided in Attachment B.

Forecast Cost Option 3 (replacement of M21 and M53 pipelines)

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Materials		1,040				**1,040**
Labour	350	6,078				**6,428**
Total	**350**	**7,118**				**7,468**

As this table highlights, the FEED survey is estimated to cost $350,000 in FY 16/17 while the cost of replacing the two pipelines in FY17/18 is estimated to cost $7.118 million. The total cost of replacing the two pipelines is forecast to be $7.468 million.

Finally, it is worth noting that the capital expenditure associated with this project will not offset any operating expenditure because the pipelines will continue to be surveyed in accordance with applicable standards. The capital expenditure can, however, be expected to avoid possible future opex (up to $1 million) associated with emergency repairs and customer relights should there be a major gas escape.

7 Consistency with National Gas Rules

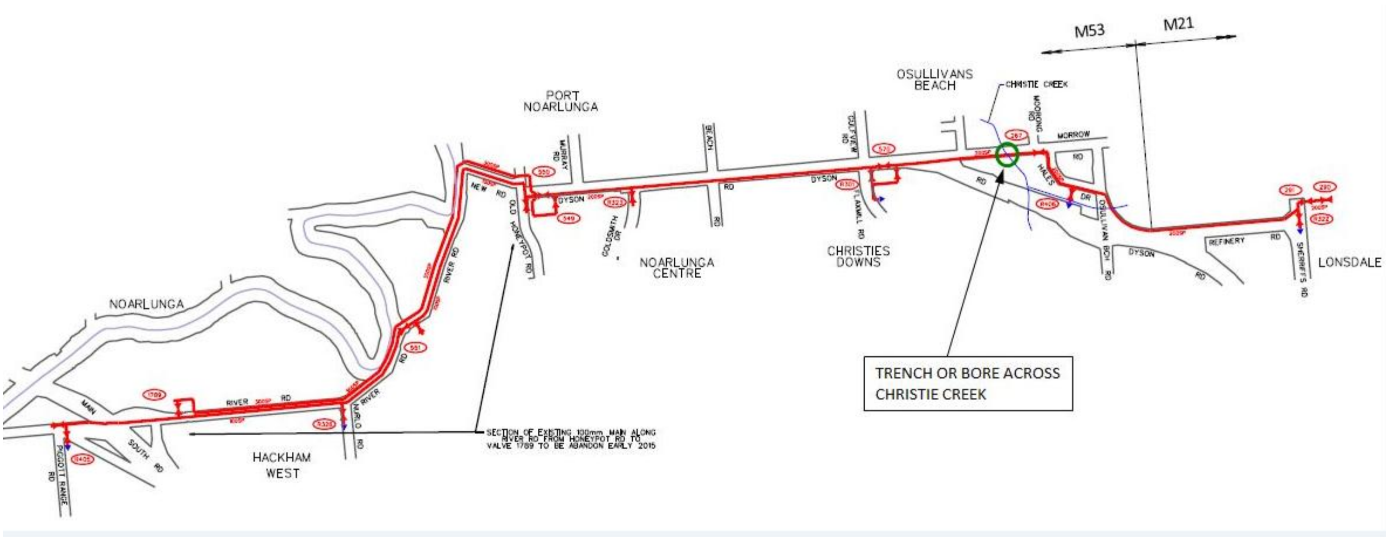
Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers the forecast capital expenditure is:

- *Prudent* – The expenditure is necessary to ensure that the ongoing integrity of the TP mains is maintained and there are no major gas escapes that could impact public safety and reliability of supply. The expenditure is also of a nature that a prudent service provider would incur.
- *Efficient* – The replacement of the TP mains is the most cost effective long term option and can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The manner in which AGN intends the replacement to be carried out (ie, FEED study to be carried out internally and field work carried out by external contractors that will be selected through a competitive tender) can also be considered efficient.
- *Consistent with accepted and good industry practice* – The identification and rectification of pipeline integrity issues as outlined above and the reduction of risk to as low as reasonably practicable in a manner that balances cost and risk is consistent with Australian Standard AS2885 and therefore in keeping with accepted and good industry practice.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The forecast expenditure is the most cost effective long-term option as demonstrated in section 6.

The capital expenditure can therefore be viewed as being consistent with rule 79(1)(a) of the National Gas Rules. The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)).

ATTACHMENT A – TP Pipelines M21 and M53 Replacement Concept Plan.



ATTACHMENT B - Detailed Cost Breakdown

Option 3 – Replacement of M21 and M53

The cost of replacing the M21 and M53 pipelines has been based on the actual contractor and material costs incurred in the Greenhill Road replacement, which is the most recent project that was carried out that is of a similar nature to what is contemplated in this case and was also subject to a competitive tender. The actual unit rate for the Greenhill Road project [redacted], which as highlighted at the bottom of the table below is consistent with what has been assumed when developing the $7.468 million estimate.

Item	$'000
[redacted]	693
[redacted]	347
[redacted]	218
[redacted]	231
[redacted]	119
[redacted]	20
[redacted]	9
[redacted]	5,260
[redacted]	31
[redacted]	540
Total	**7,468**

$7,468, 000 for 5.2 km = $1436/metre

Option 2 – Pipeline Repair/Remediation (sleeve repair and relaying the pipe under Christies Creek)

Estimated Cost of repairing sleeves:

The cost of repairing the sleeves has been based on the cost of recent work that involved similar excavations and repairs (note this recent work involved five concurrent excavations at a single site):

[redacted]

TOTAL COST per 5 joints	**$50,380**
TOTAL COST per joint	**$10,076**

- **Traffic management including water barrier**

[redacted]

Duration Total 5.5 days for 5 excavations

- **Coal tar enamel removal**

21% (i.e. 1.1km of the 5.16km) of the pipeline has coal tar enamel coating

Coating contains non-friable asbestos

[redacted]

- **Backfilling material**

[redacted]

- **Road profiling**

[redacted]

- **Number of joints to be rehabilitated =**

Pipeline total length divided by length of pipe plus 10% for bends, fittings less joints already rehabilitated

Pipeline total length	5160m
Length of pipe	12m
Joints already rehabilitated	20
Number of joints to be rehabilitated = (5160m / 12m) x 1.10 – 20=	450 joints

- Number of excavations and repairs: 450

[redacted]

- [redacted]

Total cost of this option= $4,984,200

Estimated cost to relay pipeline under Christies Creek at Morrow Road

The estimated cost of relaying the pipeline under Christies Creek is set out in the table below. The estimates in this table are based on a bottom up calculation carried out by capital works personnel who have direct experience in this type of work.

Description	Labour $'000	Materials $'000
[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]		
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]

ATTACHMENT C – Risk Assessment

The top panel in the two tables below sets out the results of the risk assessment assuming TP pipelines M21 and M53 are not remediated (untreated risk), while the bottom panel sets out the residual risks if the remediation works outlined under Option 2 and Option 3 are implemented. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

Option 2 – Pipeline Repair/Remediation

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	
	Consequence	*Medium*	*Insignificant*	*Major*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Low*	*High*	*Low*	*Moderate*	*Moderate*	*Moderate*	***118***
		18	*07*	*29*	*10*	*18*	*18*	*18*	
Residual Risk	Likelihood	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Medium*	*Insignificant*	*Major*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Negligible*	*High*	*Negligible*	*Moderate*	*Moderate*	*Moderate*	***88***
		14	*04*	*20*	*08*	*14*	*14*	*14*	

Option 3 – Pipeline Replacement

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	
	Consequence	*Medium*	*Insignificant*	*Major*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Low*	*High*	*Low*	*Moderate*	*Moderate*	*Moderate*	***118***
		18	*07*	*29*	*10*	*18*	*18*	*18*	
Residual Risk	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Medium*	*Insignificant*	*Major*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Low*	*Negligible*	*Moderate*	*Negligible*	*Low*	*Low*	*Low*	***44***
		06	*01*	*16*	*03*	*06*	*06*	*06*	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA21a

PROJECT REFERENCE	
Network	AGN– SA
Project No.	SA21a
Project Name	TP Pipeline Corrosion under HSS
Budget Category	Capex
Risk and Priority	High from an operational perspective, Priority 2
Reference Docs	N/A
Confidentiality Claim	Yes
PROJECT APPROVAL	
Prepared By:	Mujibur Rahman, *Corrosion Engineer*
Reviewed By:	Chris Liew, *Integrity Manager*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Table 1: Project Overview

Rationale for Project	The South Australian distribution network has approximately 130 km of transmission pressure (TP) pipelines laid mainly in the 1970s and 1980s when industry best practice was to use heat shrink sleeves (HSS) to protect field-welded joints against corrosion. Dis-bonding of the HSS can and often does lead to pitting corrosion of the steel under the sleeves. Based on recent excavations on the M21 and M53 pipelines (which span across metropolitan Adelaide), it's expected that other transmission pipelines where heat shrink sleeves have also been used, may have similar corrosion issues. The presence of corrosion presents a significant risk of a major gas escape that could affect the safety and reliability of supply to 21,000 customers. The risks associated with this issue have been rated as High (Priority 2).
Options Considered	Three options were considered to address the risk imposed by corrosion issues: • Option 1: Do nothing. Leave the network exposed to the risk of a major gas release with the potential to cause significant personal injury and/or property damage, and the potential loss of supply to 21,000 customers. Rectification of any damage due to a major gas release has been estimated as approximately $1million. • Option 2: Utilise intelligent pigging to survey and monitor corrosion on these pipelines. this option would typically be preferred, however the pipelines are located in metropolitan Adelaide and due to the numerous plug valves and tight bends in this section of the network, the use of intelligent pigging is restricted. • Option 3: Undertake exploratory excavations to investigate and remediate corrosion. This remains the only viable option available in order to mitigate the risks posed by corrosion on these TP pipelines. By undertaking these excavations, the risk of a major gas release would be reduced to as low as reasonably practicable.
Option Selected	Option 3 has been selected because it is the most effective method to mitigate the risk of corrosion contributing to a major gas release. Implementing this option will reduce the risk to as low as reasonably practicable, consistent with Australian Standard AS2885 (Pipelines – Gas and liquid petroleum pipelines).
Project Cost	$3.3 million ($2014/15) over the next AA period.
Consistency with the NGR	The excavation of these assets complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • The excavations are necessary in order to maintain and improve the safety of

	services and maintain the integrity of services (rule 79(1)(b) – rules 79(c)(i)-(ii); and • The costs are such that would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (rule 79(1)(a)).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. Stakeholders value AGN's high reliability of supply and support AGN's continued provision of this level of service. This initiative is consistent with the "Maintain" operational theme developed in conjunction with stakeholders as part of AGN's recent stakeholder engagement program. More information on our stakeholder engagement program and results is provided in Chapter 3 of the Access Arrangement Information document.

2 Background

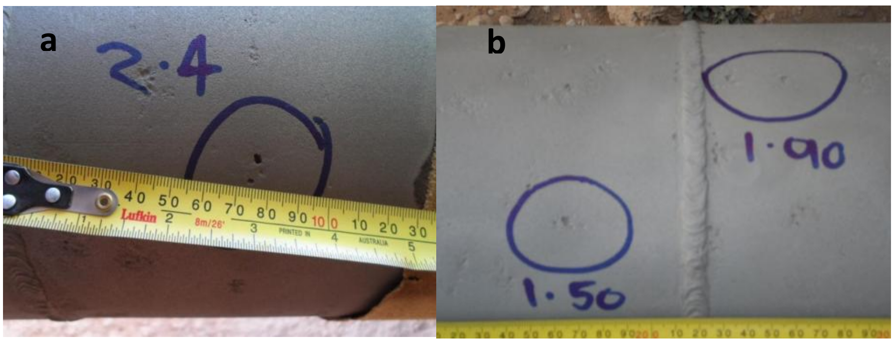
The SA distribution network has approximately 130 km of transmission pipelines (spanning the Adelaide metropolitan area) laid mainly in the 1970s and 1980s when the practice was to use heat shrink sleeves (HSS) over the field-welded joints for corrosion protection. Dis-bonding of the HSS can and often does lead to pitting corrosion of the steel under the sleeves. Corrosion occurs when the protective coating has dis-bonded and water has entered through a small coating defect. As the corrosion occurs beneath the surrounding coating, the effectiveness of the cathodic protection system is limited.

Direct Current Voltage Gradient (DCVG) surveys are currently used to monitor the condition of these transmission pipes and to locate possible corrosion points. They are effective in locating coating defects which are points where corrosion is likely to occur. However, they are not as effective at *early* detection of corrosion under dis-bonded coating.

Recent excavations of 20 joints along the M21 and M53 pipelines revealed dis-bonding of the HSS at all the joints and substantial corrosion scattered over the surface of the pipes. This finding was consistent for each of the 20 excavations.

In general, corrosion was mostly found to be in the form of tunnelling pit corrosion, with varying depths of up to 2.4mm (i.e. up to 38% of the pipe wall thickness), when measured using a manual pit gauge.

An example of the excavation findings are shown below:



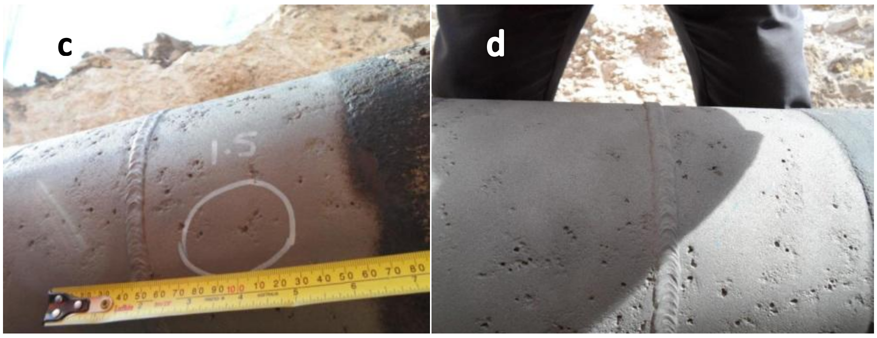


Figure: Photos taken from HSS excavation sites of M21 and M53 pipelines, showing deep tunnelling pits (a and b) scattered (c and d) over pipe surface.

Based on prior experience relating to the results of recent excavations on the M21 and M53 pipelines, it is expected that similar transmission pipelines (approximately 130 km in total) where HSS have also been used, will have similar corrosion issues that are not currently being picked up by the DCVG surveys.

Typically this type of corrosion is picked up through the "intelligent pigging" of pipelines, however the transmission network within the Adelaide metropolitan network was not constructed to be pigged, with numerous plug valves and tight bends preventing the passage of an intelligent pig.

Following the results of these excavations, a strategy has been developed in order to check the levels of corrosion on the TP pipelines, which are currently subject to DCVG surveys. Because intelligent pigging methods cannot be used in the Adelaide metropolitan area due to the design of the network, the only remaining option is to undertake exploratory excavations on relevant sections of the TP pipelines.

As outlined in Chapter 3 of the Access Arrangement Information, AGN has undertaken a comprehensive engagement program to better understand the values of stakeholders. During this engagement, stakeholders clearly indicated that they viewed gas as a reliable source of energy and indicated that they would like high levels of safety and reliability maintained. Consistent with the above insight, exploratory excavations of TP pipelines will enable AGN to continue to provide a safe and reliable supply of natural gas to customers.

3 Risk Assessment

The key issues associated with corrosion of these pipelines consist of:

- A major gas release resulting in a jet fire causing injuries and/or property damage; and
- The potential loss of supply to several thousand consumers should the mains require isolation for emergency repairs.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. Further detail on the risk assessment that has been carried out can be found in Attachment A.

The untreated risk associated with this project has been assessed as "High" (given the risk associated with supply loss to a significant number of consumers) and as such has been assigned Priority 2.

4 Key Drivers and Assumptions

The key drivers and assumptions for this project are as follows:

- Significant corrosion issues have been found at the field joints on TP mains due to ineffective bonding of the HSS to the steel;
- If field joint coating repair is not carried out, the remaining life of these pipelines will be significantly reduced;
- It is reasonable to expect that corrosion under HSS is not limited to the M21 and M53 pipelines; and
- Repair of the field joint coatings is expected to extend the life of the pipelines.

5 Options

Three options have been considered in order to develop the best approach to rectifying the risks associated with this issue. These options are:

- Option 1 – do nothing.
- Option 2 – utilise intelligent pigging in order to survey suspected corrosion on the TP pipelines.
- Option 3 – excavate TP pipelines in order to investigate suspected corrosion.

The costs and benefits associated with each of these three options are summarised in the table below. As demonstrated in the table, Option 1 will do nothing to reduce the risk to human health and safety and the safety and reliability of services associated with a major gas escape. This option is therefore not considered viable. Options 2 and 3, on the other hand, should both reduce the likelihood of a major gas escape, however the intelligent pigging technique cannot be used in the Adelaide metropolitan area, where these TP pipelines are located.

Option 3 therefore remains as the only remaining viable option.

Item	Option 1 Do Nothing	Option 2 Utilise intelligent pigging	Option 3 Excavate and repair
Costs/Risks	Risk of a major gas escape that adversely affects: • human health and safety and property and gives rise to compensation claims; and/or • the safety and reliability of supply to 21,000 consumers in Adelaide's southern suburbs if repairs are required, which will give rise to repair costs and the cost of customer relighting ($1 million).	Intelligent pigging cannot be used in the Adelaide metropolitan area, due to the way in which the network is constructed.	Costs of conducting 52 excavations per year have been estimated to total $3.3 million ($2014/15). Estimated costs per excavation have been based on recent excavations conducted on the M21 and M53 TP pipelines and include an assumption regarding the percentage of HSS joints requiring structural repair. Full cost details are provided in Section 5.
Benefits	No upfront costs to excavate and repair the TP pipelines.	Intelligent pigging is a more cost-effective method to use in terms of surveying the condition of underground pipelines.	This Option provides effective mitigation of the risk associated with a major gas release and potential for significant personal injury and/or property damage, and is in line with good industry practice.

6 Forecast Cost for the upcoming AAP

Option 3 has been selected as the proposed plan to mitigate the risks associated with suspected corrosion on the M21 and M53 TP pipelines.

This Option includes:

- Conducting 52 excavations per year, and
- Costs of repairing an estimated 10% of joints excavated.

Both elements of this cost estimate have been based on the actual costs incurred for the recent exploratory pipeline excavation and repair on the M21 and M53 TP pipelines. A detailed cost breakdown is provided in Tables 3 and 4 below.

In determining the appropriate volume of excavations to undertake over the next AA period, an assessment was made in order to balance the risks posed by corrosion and the costs involved with exploratory excavations. The volume of excavations proposed in Option 3 is based on a minimum requirement of conducting two excavations per one kilometre of pipeline. This requirement is based on engineering experience within APA, given that there could be significant variations in the condition of pipelines over one kilometre. Given there are 130 kilometres of pipeline to excavate and repair, the calculation is outlined below:

- 130 kilometres x 2 excavations per kilometre = 260 excavations
- 260 excavations over five years = 52 excavations per year

[redacted]

Note: all costs are in $s 2014/15

7 Consistency with the National Gas Rules

Consistent with the requirements of Rule 79 of the National Gas Rules, AGN considers that the operational expenditure being sought for this project is:

- *Prudent* – The expenditure is necessary in order to ensure the ongoing integrity of the TP network is maintained and to ensure there are no major gas escapes that could impact public safety and reliability of supply;
- *Efficient* – AGN considers this proposal as the only practical and effective option to efficiently address the risk. Engineering assessments and design will be carried out by internal staff and field work will be carried out by external contractors based on competitively tendered rates;
- *Consistent with accepted and good industry practice* – The ongoing effective integrity management of this pipeline is a requirement of good industry practice as reflected in AS 2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management. Failure to effectively maintain these pipelines would be contrary to this code; and
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – Failure to maintain the integrity of these pipelines would result in additional expenditure (reactive response to a major gas escape and bringing forward replacement) which is not consistent with the principle of lowest sustainable cost of delivering services.

AGN therefore considers that the capital expenditure is justifiable under Rule 79 of the National Gas Rules as the capital expenditure is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

ATTACHMENT A – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Significant*	*Insignificant*	*Significant*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Negligible*	*High*	*Low*	*Low*	*Moderate*	*Low*	***77***
		15	*04*	*20*	*08*	*08*	*14*	*08*	
Residual Risk	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Significant*	*Insignificant*	*Significant*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Low*	*Negligible*	*Moderate*	*Negligible*	*Negligible*	*Low*	*Negligible*	***35***
		06	*01*	*13*	*03*	*03*	*06*	*03*	

Priority		**Priority Description**
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

Australian Gas Networks

APA Group

BUSINESS CASE - SA22

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA22
Project Name	Below Ground TP Regulator Replacement
Budget Category	Capex
Risk and Priority	Moderate, Priority 3
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachment B)
PROJECT APPROVAL	
Prepared By:	Annabel Sandery, *Project Engineer*
Reviewed By:	Scott Ryan, *Manager Capital Projects*
Approved By:	Peter Sauer, *General Manager SA Networks*

1. Project Overview

Rationale for Project	This project is a continuation of Australian Gas Networks Limited's (AGN) replacement program of below ground brick vaults, that house transmission system regulator facilities (see Attachment A for site details), which was approved by the AER in the last Access Arrangement review. These below ground brick vaults have degraded to such an extent there is water ingress and associated corrosion of pipe valves and fittings. Put simply, they have reached the end of their useful lives. If these chambers continue to be used they will pose an occupational health and safety hazard for maintenance personnel and also expose AGN to the risk of critical asset failures that could affect the supply of gas to consumers. These risks have been rated as Moderate (Priority 3).
Options Considered	Four options were considered to address the risks outlined above: • Option 1: Do nothing, which would leave AGN exposed to the risk of occupational health and safety risks and critical asset failures that could affect the delivery of gas. • Option 2: In situ refurbishment of the existing vaults. • Option 3: Replacement of 15 below ground regulator chambers in the upcoming regulatory period, that were found to be at the end of their useful life with new vaults and spring loaded 'butterfly' galvanised steel lids.
Option Selected	Option 3 was selected because Option 1 poses too high a risk to human health and safety, while the in-situ refurbishment (Option 2) cannot eliminate the occupational hazards. In contrast to these two options, Option 3 will reduce the risk to as low as reasonably practicable in a manner that better balances cost and risk than the other two options, consistent with Australian Standard AS4645 and AS2885 (Gas Distribution Network Management and Pipelines – Gas and liquid petroleum pipelines). Work commenced on replacing the 36 below ground brick vaults that were found to be at the end of their useful lives in 2012 and by the end of 2015/16 21 are expected to have been replaced, leaving 15 to be replaced in the Access Arrangement Period (AAP).
Estimated Cost	The forecast capital expenditure for the replacement program over the upcoming AAP is $4.935 million ($0.987 million per annum) (real $2014/15).
Consistency with the NGR	The replacement of these assets complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because it is: • necessary to maintain and improve the safety of services and maintain the integrity of services (rules 79(2)(i) and (ii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue to provide a safe and reliable supply of gas to

	our customers. Chapter 3 of the AAI provides more information on the stakeholder engagement.

2. Background

AGN's South Australian gas network has 80 below ground transmission pressure (TP) regulators that form the primary supply to the downstream high and medium pressure regulators. These regulators are housed in below ground vaults to reduce the risk of third party damage.

There are a number of regulators housed in below ground brick/mortar lined chambers. Rising salt damp has led to the deterioration of these allowing the ingress of ground water. This creates a very damp environment, accelerating the corrosion of pipes, valves and fittings located in the chamber. It also creates a very difficult work environment for personnel who perform regular maintenance and monitoring activities.

Access to the regulator brick chambers is via small diameter (600 millimetres) manhole access covers, which can restrict access and egress for personnel. This restricted access creates a safety hazard for maintenance personnel who may need to enter or exit this confined space environment during an emergency. Should the need arise, safety equipment for emergency access can be difficult to set up and in some cases ineffective, potentially delaying the retrieval of injured/suffocating personnel.

The configuration of pipe work of these older regulator stations requires maintenance personnel to climb over or under the pipe work to operate valves, test pressure shut off devices and read gauges. This adds to the safety hazards described above.

An example of this is the regulator pit site located in Frome Road, Adelaide. Figure 1 highlights the restricted conditions in the pit, the corrosion of all parts, the low levels of lighting and the close proximity to the road and access.

Figure 1: Regulator Pit Site on Frome Road

New standards have been developed to provide a configuration that is easier and safer to maintain. Vaults with spring loaded, "butterfly" galvanised steel lids have been designed to ensure easy access and egress as well as eliminating the need for confined space permits.

By the end of this regulatory period, 21 of the below ground brick regulator chambers will have been replaced. It is intended that an additional 15 are expected to be completed over the next AAP.

The replacement of these regulator chambers involves:

- identifying an alternative facility site;
- workshop fabrication and assembly of replacement regulator vaults;
- workshop assembly of regulator station components;
- field work associated with connection of inlet and outlet pipework;
- field commissioning of new facilities;
- field work associated with cutting, capping and removal of old regulator facilities; and
- ground reinstatement.

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to maintain our high levels safety and reliability. Consistent with the above insight, the replacement of the regulators will enable AGN to continue to provide a safe and reliable supply of natural gas to customers.

3. Risk Assessment

The damp and confined environment of the brick regulator chamber presents a risk to maintenance personnel should rapid egress be required in an emergency. There is potential for slip/strain resulting in a loss time injury and in extreme circumstances, personnel may remain trapped in the confined space resulting in a fatality.

The corrosive environment within these below ground facilities has potential for facility failure resulting in a gas leak. The critical nature of these facilities, providing the primary supply to the distribution network, creates a risk to supply should emergency repair require isolation of the facility. Depending on the location and time of year the supply to several thousands of consumers could be affected.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria (see section 3.3 of the Asset Management Plan for further information). Further detail on the risk assessment that has been carried out can be found in Attachment C. In short, the untreated risk associated with this project has been assessed as "Moderate" from a human health and safety, operational and compliance and legal perspective and has been assigned Priority 3 rating.

4. Key Drivers and Assumptions

The primary driver for this project is that below ground brick regulator chambers have reached the end of their useful lives and the continued operation of these chambers will expose:

- personnel to occupational health and safety risks because safe access into and out of brick regulators is compromised by a small manhole; and

- critical asset failures that could affect the safe and reliable delivery of gas to consumers, because the below ground regulators provide the primary supply to the distribution network and therefore create a risk to supply if emergency repair requires isolation of the regulator.

This project is also consistent with AGN's operational theme of "Maintain" network safety. It specifically relates to the following insights:

- Customers value AGN's high reliability and want AGN to keep providing the same (as a minimum) service levels.
- Customers view gas as a reliable source of energy.

Some of the key assumptions underpinning the project are set out below:

- The new regulator design, with spring loaded butterfly lids, eliminates the confined space, and the general layout significantly reduces occupational hazards.
- Fabrication and assembly of replacement regulators to be undertaken by internal personnel with field work utilising a combination of contract resources and internal supervision.

5. Options

The three options for dealing with the risks outlined above are:

- Option 1 – Do nothing.
- Option 2 – In situ refurbishment of the existing vaults.
- Option 3 – Replacement of 15 below ground regulator chambers in the upcoming regulatory period that were found to be at the end of their useful life with new vaults and spring loaded 'butterfly' galvanised steel lids.

Of the options listed above, Option 3 is the only feasible option because:

- the degradation of the brick vaults in the 15 regulator chambers is such that repair/replacement of this component of the facility is not practical, which means Option 1 is not a feasible solution; and
- the occupational hazards outlined above cannot be eliminated by in situ refurbishment, which means Option 2 is not a feasible solution.

The costs and benefits associated with Option 3 are set out in the table below.

Costs and benefits of the option 3 (replace 15 below ground regulator chambers)

Item	Option 3
Costs	Replacement cost: $4.935 m (real $2014/15)
Benefits	Reduction in occupational health and safety risks and critical asset failures that could otherwise

Item	Option 3
	affect the safe and reliable delivery of gas to consumers. Avoidance of approximately 1,000 relights ($100 per relight) should there be a major failure of one of the facilities

6. Forecast Cost for the Upcoming AAP

The table below provides a summary of the capital expenditure that is forecast to be incurred in the next AAP under Option 3. This forecast has been developed having regard to the internal resource costs,[1] external contractor rates[2] and material costs that have been incurred under the replacement program that commenced in this AAP. The contractor rates and material costs in the current replacement program are based on the costs of recent similar installations carried out over the last three years. A more detailed breakdown of the cost of replacing a single chamber can be found in Attachment B.

$'000s (Real 2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Regulator Facilities	3	3	3	3	3	**15**
Materials	240	240	240	240	240	**1,200**
Labour	747	747	747	747	747	**3,735**
Total	**987**	**987**	**987**	**987**	**987**	**4,935**

As this table highlights, the forecast cost of the replacement program in the upcoming regulatory period is $4.935 million ($0.987 million per annum) (real $2014/15).

Finally, it is worth noting that this project will have no impact on either current or future operating expenditure.

7. Consistency with the National Gas Rules

Consistent with the requirements of rule 79 of the National Gas Rules, AGN considers that the capital expenditure is:

- *Prudent* – The expenditure is necessary in order to maintain and improve the safety of services and maintain the integrity of services to customers and personnel and is of a nature that a prudent service provider would incur.

[1] These costs relate to the front end engineering and survey, fabrication and assembly, project management and supervision. The new regulator pits are engineered, fabricated and assembled internally.

[2] External contractors are required for installation and field work.

- *Efficient* – The field work will be carried out by the external contractor that has been used to date, who has demonstrated specific expertise in completing the installation of the facilities in a safe and cost effective manner.[3] The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur
- *Consistent with accepted and good industry practice* – Addressing the risks associated with the poor condition of a number of below ground transmission system regulators and replacing assets that have reached the end of their useful life is accepted as good industry practice. In addition the reduction of risk to as low as reasonably practicable in a manner that balances cost and risk is consistent with Australian Standards AS4645 and AS2885.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The sustainable delivery of services includes reducing risks to as low as reasonably practicable and maintaining reliability of supply.

The capital expenditure can therefore be viewed as being consistent with rule 79(1)(a) of the National Gas Rules. The proposed capital expenditure is also consistent with rule 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)), which includes maintaining the security of supply.

[3] Note that while other contractors have been used in the past, they have been unable to deliver the same outcomes in terms of cost effectiveness and safety as the external contractor that is currently carrying out the work.

ATTACHMENT A – TP Regulator Replacement Sites

Number	Reg Number	Primary Street Location	Secondary Street Location	Suburb	FY
1	R149	Jetty Rd	Victoria Rd	Largs Bay	Completed FY12 - FY 16
2	R150	Victoria Rd	Kolapore Ave	Largs Nth	
3	R148	Bridge Rd	Research Rd	Pooraka	
4	R147	Deviation Rd	East Tce	Thebarton	
5	R151	Cromwell Rd	Churchill Rd	Kilburn	
6	R339	Gunya Ave	Flagstaff Rd	Flagstaff Hill	
7	R161	Yatala Vale Rd	Hancock Rd	Fairview Pk	
8	R338	Finnian St	Dyson Rd	Christies Beach	
9	R158	Cooradilla Dr	Main Nth Rd	Salisbury	
10	R164	Cormack Rd	South Rd	Wingfield	
11	R337	Refinery Rd	Sherriffs Rd	Lonsdale	
12	R159	Bridge Rd	McIntyre Rd	Salisbury East	
13	R222	P.G.H BRICK CO	Greenwith Rd	Golden Grove	
14	R223	Hallett Brick	Greenwith Rd	Golden Grove	
15	R341	Oaklands Rd	Morphett Rd	Glengowrie	
16	R162	Smith Rd	Coolibah Rd	Salisbury East	
17	R163	Exeter Tce	Oxenham St	Dudley Park	
18	R340	Jervois Tce	Newland Av	Marino	
19	R342	Morphett Road	Anzac Hwy	Novar Gdns	
20	R343	Richmond Road	South Rd	Richmond	
21	R345	Goldsmith Dr	Dyson Rd	Noarlunga Dwns	
22	R346	London Rd	South Rd	Mile End Sth	1
23	R347	Church Hill Rd	Piggott Range Rd	Hackham	2
24	R344	Stephenson Ave	Brighton Rd	South Brighton	3
25	R1727	Pompoota Rd		Hope Valley	4
26	R1728	Churchill Ave	Cross Rd	Glandore	5
27	R119	Diment Rd		Salisbury North	6
28	R127	Womma Rd		Elizabeth	7
29	R303	Folkestone Rd		Dover Gardens	8
30	R315	South Tce		Hallet Cove	9
31	R310	Grand Central Ave		Hallet Cove	10
32	R406	Hales Dve		Lonsdale	11
33	R318	Black Rd		Flagstaff Hill	12
34	R118	Golden Grove Rd		Surrey Downs	13
35	R324	Augusta St		Glenelg	14
36	R130	Old Port Rd		Queenstown	15

ATTACHMENT B – Detailed Cost Breakdown

The table below provides a breakdown of the cost of replacing a single TP chamber.

TP Regulator Replacement – Unit Cost		
Item	**Description**	**$'000**
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
9	GRAND TOTAL	329

ATTACHMENT C – Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the below ground TP regulators are not replaced (untreated risk), while the bottom panel sets out the residual risks if the replacement works outlined under Option 3 are implemented. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance & Legal	Financial Impact	Total Score of Risk Level
Risk Untreated	**Likelihood**	Possible	N/A	Possible	Possible	Possible	Possible	Possible	
	Consequence	Medium	N/A	Medium	Minor	Minor	Medium	Insignificant	
	Risk Level	*Moderate*	*N/A*	*Moderate*	*Low*	*Low*	*Moderate*	*Negligible*	
		14		*14*	*08*	*08*	*14*	*04*	62
Residual Risk	**Likelihood**	Rare	N/A	Rare	Rare	Rare	Rare	Rare	
	Consequence	Medium	N/A	Medium	Minor	Minor	Medium	Insignificant	
	Risk Level	*Low*	*N/A*	*Low*	*Negligible*	*Negligible*	*Low*	*Negligible*	
		06		*06*	*03*	*06*	*06*	*01*	28

Priority		**Priority Description**
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE – SA24

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA24
Project Name	Two Wells
Budget Category	Capex
Risk Rating	Low
Reference Docs	
Confidentiality Claim	Yes
PROJECT APPROVAL	
Prepared By:	Ed Macolino, *Manager Strategic Development*
Reviewed By:	Peter Gayen, *Networks Commercial Manager*
Approved By:	John Ferguson, *Group Executive Networks*

1 PROJECT OVERVIEW

Two Wells is a small town north of Adelaide. It has a population of 2,293 (Census, ABS, 2011) and is situated in the District Council of Mallala.

The population of Mallala is predicted to more than double in size, with Two Wells identified as the major growth area within the district.

The Hickinbotham Group has worked with the District Council to develop a shared vision for the future development of Two Wells. AGN has worked closely with both to ensure the availability of gas infrastructure in the Two Wells development.

AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. A key outcome of this engagement was drawing upon stakeholder values and insights to identify the operational themes to include, maintain or improve. This initiative is considered to be consistent with the Improve theme as its implementation will allow us to improve our natural gas reticulation network to provide capacity to supply stakeholders in this growth precinct.

More information on our stakeholder engagement program and results is provided in Chapter 3 of the Access Arrangement Information document.

2 COST AND TIMING

Table 1 provides a breakdown of the capital expenditure required for the Two Wells Reticulation project for the regulatory period.

The forecast cost is based on experience in reticulating greenfield developments. It applies standard assumptions with respect to connections, growth and economics.

The unit rates used for this project are in accordance with standard practice and based on recent outcomes for connections and reticulation of a development of this size (see Table 3).

The project will delivered by a mix of external and internal labour. This mix is based on historical averages and is taken into account by the unit rates applied.

The project timeframe with respect to provision of infrastructure and connection of customers is based on discussions with the developer.

$,000 Real 2014/15 – excluding overheads						
	2016 -17	2017 -18	2018 -19	2019 -20	2020 -21	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				[redacted]		[redacted]
[redacted]				[redacted]		[redacted]

Table 1: Two Wells Reticulation Capital Expenditure by Activity

Asset Category	2016 -17	2017 -18	2018 -19	2019 -20	2020 -21	Total
Supply Mains (metres)				9000		9000

Table 2: Two Wells Reticulation Scope of Work

$ Real 2014/15					
	2016 -17	2017 -18	2018 -19	2019 -20	2020 -21
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 3: Unit Costs

3 BACKGROUND

Commencing in 2010, the Hickinbotham Group and the District Council of Mallala entered into detailed discussions on the approach to infrastructure provision for Two Wells. These discussions canvassed options for the provision of infrastructure to serve both the existing established township and the proposed future urban growth area north of the town. It was agreed that the Hickinbotham Group would take responsibility for internal infrastructure including the provision of services such as natural gas.

As a result of this process, the District Council implemented the rezoning of land immediately to the north of the existing township. The District Council and the Hickinbotham Group worked together to prepare a Residential Development Plan Amendment (DPA) for the Two Wells development.

On 30 August 2013, the Minister for Planning announced the approval of the Two Wells Residential Development Plan Amendment (DPA), a major milestone for this significant urban development.

The project includes plans for more around 3200 new homes, a private school and community sporting facilities. The 300 ha site is about 800 m north of the existing town centre. Housing will be split into two "villages" - one featuring large blocks between 1200sq m to 1 ha and the other with blocks that will likely be as small as 350 sq m up to 1000 sq m - that will be sold in stages.

AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. Of particular relevance, stakeholders have expressed the following views;

1. Are concerned about rising energy costs and control over their bill
2. View gas as a reliable source of energy
3. Value initiatives that improve community safety across the network
4. Support expanding and improving the network where there is a clear benefit to residents and business
5. Are more concerned with the overall price of gas than the tariff structure
6. Trust AGN is meeting its environmental obligations

Consistent with the above insight the extension of gas infrastructure in this growth precinct will provide the key stakeholders with an economically prudent energy source, safely and reliably.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for the Tow Wells project are:

- Around 3,200 customers are expected to connect to natural gas in Two Wells. The customer number forecasts have been developed based on forecasts provided by the developer and then benchmarked against other projects with which AGN has experience. AGN has conducted surveys that also support the demand forecast.
- These connections are included in the total Access Arrangement Demand forecasts.
- Construction of 9,000 metres of supply main;
- Application of the Adelaide region tariffs
- A Consumer Price Index (CPI) of 2.5 per cent per annum;
- An analysis period of 20 years.
- Operating costs have been treated as incremental to existing business.

A key driver is also that this project is consistent with our operational theme of “Improve” network safety. It specifically relates to the following insights:

  - Customers value initiatives that improve community safety across the network.
  - Customer support expanding and improving the network where there is a clear benefit to residents and businesses.

Cost Benefit Analysis

High level economic analysis of the costs and revenues for the project indicates that the project will achieve positive returns. It is expected that the project will identify a return on investment in excess of the current hurdle rate.

Table 5; summarises the proposed project's cashflows and profitability.

	Year 0 $m	Year 1 $m	Year 2 $m	Year 3 $m	Year 4 $m	Year 5 $m	Year 10 $m	Year 15	Year 20 $m	Year 30 $m
Capital Cost	5.54	0.16	0.19	0.24	0.25	0.28	0.53	0.81	0.25	0.00
Revenue	0	0.04	0.14	0.2	0.24	0.29	0.64	1.2	1.73	1.75
Operating Costs	0	0	0	0	0.01	0.01	0.02	0.05	0.07	0.07
Net Cashflow	-5.54	-0.12	-0.05	-0.04	-0.02	0.00	0.09	0.34	1.41	1.68
Depreciation	0.09	0.10	0.10	0.11	0.12	0.13	0.19	0.28	0.36	0.36
EBIT	-5.63	-0.22	-0.15	-0.15	-0.14	-0.13	-0.10	0.05	1.05	1.32
Interest	0.35	0.36	0.38	0.39	0.41	0.42	0.57	0.81	1.01	1.01
Profit/Loss	0.35	-0.58	-0.52	-0.54	-0.54	-0.55	-0.67	-0.76	0.04	0.31

Table 5: Two Wells Project Economic Analysis

5 JUSTIFICATION

Consistent with the requirements of rules 79(1)(a) and (2)(b) and 91 of the National Gas Rules, AGN considers that the capital expenditure to provide gas reticulation to domestic and I&C customers in the Two Wells development is:

- *Prudent* – the expenditure will expand gas supply services to the Two Wells township providing additional growth to AGN. The project is based on a conservative approach to forecasting customer connections, which has been deliberately taken to ensure the financial viability of the proposed network extension. An economic analysis of the costs and revenues to be received under the proposed project indicates that the project will achieve a positive return of 10.6 per cent (pre-tax nominal) over 20 years.

- *Efficient* – The forecast project costs are been based on historical average costs. The supply main has been designed to minimise length and the reticulation mains have been designed to maximise customer numbers during the development phase,years.

- *Consistent with accepted and good industry practice* – The proposed project involves expanding the network to meet potential demand growth, where the capital investment has been justified on the basis of an appropriate economic return. In addition, the demand forecasts underpinning the economic analysis are considered to be conservative. A higher number of customer connections than that forecast in the model may be achieved, and may ultimately provide greater economic returns on investment; and

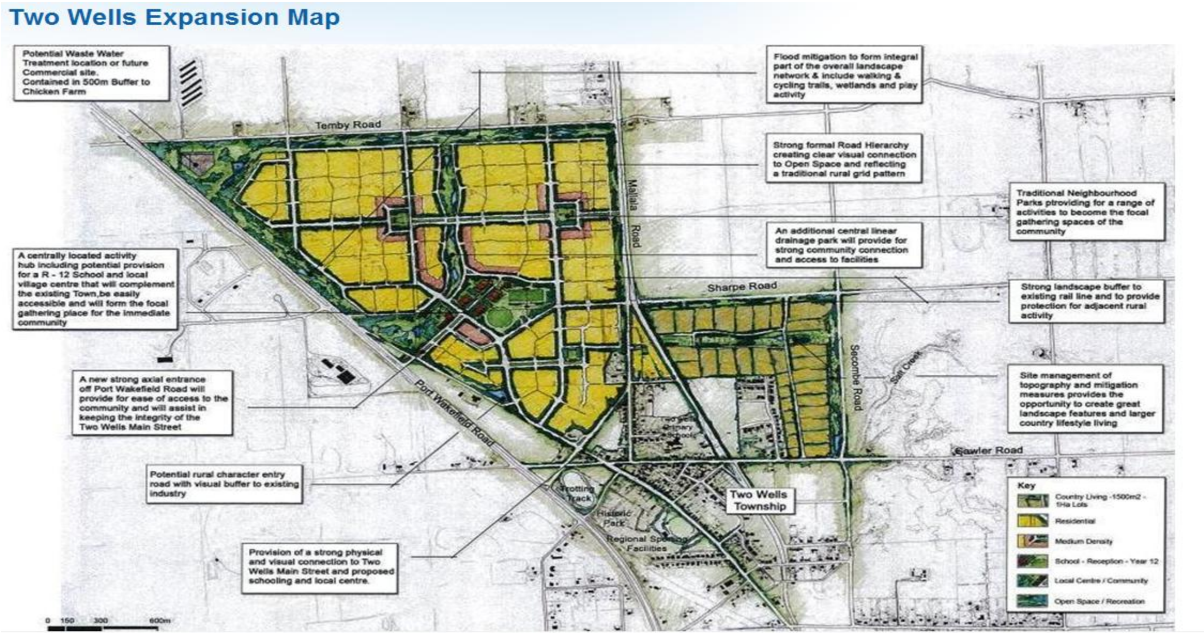
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* - The project has been assessed to provide an appropriate return to AGN and will help maintain the viability of

AGN's South Australian gas network. In particular it will help to spread the largely fixed costs of operating a gas network over a larger customer base, therefore alleviating any future requirements to raise customer tariffs. This will therefore assist in achieving the lowest sustainable cost of delivering pipeline services.

6 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken, then AGN will be unable to expand the network to meet potential future demand identified in Two Wells. This will limit AGN's growth opportunities, and potentially lead to higher tariffs as the opportunity to spread the largely fixed costs of operating a gas network across a larger customer base will be foregone.

ATTACHMENT A – Two Wells Expansion Map



BUSINESS CASE – SA28

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA28
Project Name	Above Ground PE Pipe and Fittings
Budget Category	Capex
Risk and Priority	High, Priority 2
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes
PROJECT APPROVAL	
Prepared By:	Annabel Sandery, *Project Engineer*
Reviewed By:	Spiro Ellul, *Manager Field Operations*
Approved By:	Peter Sauer, *Manager SA Networks*

1 Project Overview

Rationale for Project	This project is a continuation of Australian Gas Networks Limited's (AGN) strategy to replace residential polyethylene (PE) services and inlet services located above ground. [redacted] The risks associated with these assets have been rated as High (Priority 2).
Options Considered	Two options were considered to address the risks outlined above: • Option 1: Do nothing, which would leave the public exposed to the risks outlined above. • Option 2: Replace residential above ground PE pipes and fittings with a copper up stand and terminating with metal fittings.
Option Selected	[redacted] the replacement option was found to be the most prudent solution to reduce the risk to as low as reasonably practicable and in a manner that balances cost and risk, consistent with Australian Standard AS4645 (Gas Distribution Network Management). A decision was therefore made to replace the existing fittings. Work on this program commenced in 2013 and by the end of 2015/16 5,000 services are expected to be replaced, leaving approximately 20,000 to be replaced. Of the 20,000, 15,000 are expected to be replaced in the next Access Arrangement Period (AAP) and the remainder in the following period.
Estimated Cost	The forecast capital expenditure for this replacement program over the upcoming regulatory period is \$7.125 million (\$1.425 million per annum) (real \$2014/15).
Consistency with the NGR	The replacement of these assets complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because it is: • necessary to maintain and improve the safety of services and maintain the integrity of services (rules 79(2)(i) and (ii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (rule 79(1)(a)).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is considered to be consistent with the *Improve* theme because its implementation will allow AGN to improve network safety. More information on the stakeholder engagement program and results is provided in Chapter 3 of the AA Information (AAI).

2 Background

In the 1980s it was common practice to insert 10mm poly pipe into 20mm cold bends acting as inlet service standpipes, terminating approximately 50mm before the domestic service regulator. This practice was applied wherever inlet services were replaced as part of the mains replacement program or newly installed. These inlet services operate at either medium pressure (notionally 100 kPa) or high pressure (notionally 250 kPa).

It has subsequently been established that there are several risks associated with above ground PE pipe and fittings, including:

- pipe degradation of the section of pipe exposed to sunlight (ultra violet light damage) leading to failure and major release of gas;
- melting of the service pipe in the event of a fire exacerbating an emergency situation;
- external mechanical interference and subsequent major release of gas; and
- use of plastic compression (Philmac) fitting connecting the service to the regulator and the susceptibility of these fittings to leak over time.

The current practice is therefore for the above ground service to consist of steel or copper risers terminating with metal fittings.

Given the risks outlined above, a survey of all residential inlet services was undertaken in 2011 with about 26,500 above ground poly (AGP) standpipes identified. A further 22,000 sites could not be assessed because of site access issues, but on a pro rata basis a further 1,500 sites with above ground PE pipe and fittings are likely to be present.

A replacement program commenced in 2013 and approximately 5,000 above ground PE inlet services are expected to be replaced by the end of the current regulatory period, leaving more than 20,000 sites to be replaced in future years. Based on contractor performance to date and resource availability, a replacement rate of approximately 3,000 services per year is considered sustainable. It has therefore been assumed that 15,000 replacements will occur in the next AAP and the remaining 5,000 in the subsequent AAP.

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they:

- valued initiatives that improve community safety; and
- were supportive of initiatives that improved the network where there was a clear benefit to residents and business.

Consistent with the above insights, replacing the above ground PE pipe and fittings in residential areas will increase the safety of people and properties.

As well as being consistent with the operational theme relating to improving the network, 85% of workshop participants indicated they would be willing to pay up to $0.50 per year more to replace identified instances of above ground PE pipe and fittings.

3 Risk Assessment

The key risk addressed by this project is the potential for gas from a damaged service entering a building, and accumulating to explosive levels. An explosion could result in personal injury and/or damage to buildings.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria (see section 3.3 of the Asset Management Plan for further information). Further detail on the risk assessment that has been carried out can be found in Attachment B. In short, the untreated risk associated with this project has been assessed as "High" and as such has been accorded a Priority 2 rating.

4 Key Drivers and Assumptions

The key assumptions and drivers for the project are as follows:

- As outlined in the preceding section there is a risk that:
  - exposed above ground PE pipes and fittings could be damaged (eg, through fire, UV or mechanical interference) resulting in a major gas escape; and
  - failure of plastic compression (Philmac) fittings between the regulator and the PE pipe have a history of failure with potential for significant gas escape.

  Any major gas release close to an adjoining building has potential to cause significant damage to buildings and/or personal injury. The key driver for the project is therefore to reduce the risk to as low as reasonably practicable and in a manner that balances cost and risk, consistent with Australian Standard AS4645.

- This project is consistent with AGN's operational theme of "Improve" network safety. It specifically relates to the following insights:
  - Customers value initiatives that improve community safety across the network.
  - Customer support improving the network where there is a clear benefit to residents and businesses.

5 Options

The two options for dealing with the risks outlined above are:

- Option 1: Do nothing; or

- Option 2: Replace the PE pipes and fittings with a copper up stand and terminating with metal fittings.

The costs and benefits of these two options are summarised in the table below.

Costs and benefits of the options

Item	Option 1	Option 2
Costs	Risk to human health and safety and damage to property and consequent compensation claims (buildings replacement circa $1 million and compensation for major injury/loss of life circa $5-$10 million). If an explosion occurs additional costs will be incurred replacing the service and any other infrastructure affected by the explosion.	Replacement cost: $475 per replaced service (real $2014/15)
Benefits	No upfront costs to replace services.	Reduce the risk of a major gas escape and the consequent impact on public safety and reliability of supply to as low as reasonably practicable and in doing so reduce the risk of compensation claims.

Because of the risks to human health and safety posed by the above ground PE services, the replacement option (Option 2) was found to be the most prudent solution to address the risk because it will mitigate potential liability claims that could amount to several million dollars should there be an explosion. A decision was therefore made to reduce the risk to as low as reasonably practicable (consistent with AS4645) by implementing Option 2.

6 Forecast Cost for the Upcoming AAP

The table below provides a summary of the capital expenditure that is forecast to be incurred in the next AAP under Option 2, which has been estimated on the basis of the following assumptions:

- The contractor rates and material costs are based on the results of a competitive tender process that was conducted for similar related activities. The contractors that carried out these activities have agreed to undertake the scope of work outlined under Option 2 using the same rates that were established in the tender.
- The average service replacement rate is assumed to be 3,000 per annum (15,000 over the regulatory period). This is considered a sustainable rate based on contractor performance to date and resource availability.

A more detailed cost breakdown can be found in Attachment A.

Capital expenditure forecast excluding overheads ($'000 real $2014/15)

Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Materials	225	225	225	225	225	1,125
Contractor Labour	1,140	1,140	1,140	1,140	1,140	5,700
Direct Labour	60	60	60	60	60	300
Total	**1,425**	**1,425**	**1,425**	**1,425**	**1,425**	**7,125**

As this table highlights, the forecast cost of the replacement program in the upcoming regulatory period is $7.125 million ($1.425 million per annum) (real $2014/15).

Finally, it is worth noting that there is no material opex trade-off arising from this project because while the capital expenditure may result in the avoidance of some leaks at meters, this is not considered material.

7 Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers the forecast capital expenditure is:

- *Prudent* – The expenditure is necessary in order to maintain and improve the safety of services to customers and the public and is of a nature that a prudent service provider would incur.
- *Efficient* – The field work will be carried out by external contractors that were selected through an earlier competitive tender for similar related activities at the same rates that were established in this tender and can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – Reducing the risks associated with these assets to as low as reasonably practicable in a manner that balances cost and risk is consistent with Australian Standard AS4645 (Gas Distribution Network Management) and therefore in keeping with accepted and good industry practice.
- *To achieve the lowest sustainable cost of delivering pipeline services* – Reducing risk to as low as reasonably practicable in this case is consistent with the objective of achieving the lowest sustainable cost given the scale of the liability claims that could be made if the assets aren't replaced and an explosion occurs that causes personal injury, fatalities and/or damage to building.

The capital expenditure can therefore be considered consistent with rule 79(1)(a) of the National Gas Rules. The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)), which includes maintaining the security of supply.

ATTACHMENT A – Detailed Cost Breakdown

The table below provides a breakdown of the annual service replacing cost forecast for the upcoming regulatory period, which has been developed having regard to the material costs and labour rates established through a recent competitive tender.

Service Replacement Cost Summary ($'s real 2014/15 – excluding overheads)	
Item	**Unit Cost $**
Total Materials	**75**
[redacted]	15
[redacted]	28
[redacted]	20
[redacted]	12
Total Labour	**400**
Contracted Crew - 4hrs @$95/hr	380
Supervision, Administration, Planning	20
Total (per service)	475
Annual Service Replacement - No.	3,000
Total Annual Cost	**1,425,000**

ATTACHMENT B – Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the above ground PE pipes and fittings are not repaired (untreated risk), while the bottom panel sets out the residual risks if Option 2 is implemented. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance	Financial Impact	Total Score of Risk Levels
Risk Untreated	**Likelihood**	Possible	Possible	Possible	Possible	Possible	Possible	Possible	
	Consequence	*Major*	*Minor*	*Minor*	*Insignificant*	*Medium*	*Medium*	*Minor*	
	Risk Level	*High*	*Low*	*Low*	*Negligible*	*Moderate*	*Moderate*	*Low*	
		25	*08*	*08*	*04*	*14*	*14*	*08*	*81*
Residual Risk	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Major*	*Minor*	*Minor*	*Insignificant*	*Medium*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Negligible*	*Negligible*	*Negligible*	*Low*	*Low*	*Negligible*	
		16	*03*	*03*	*01*	*06*	*06*	*03*	*38*

Priority		**Priority Description**
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

Australian Gas Networks | APA Group

BUSINESS CASE - SA30

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA30
Project Name	Small Plant & Equipment
Budget Category	Capex
Priority	2
Reference Docs	Safety Non Negotiables
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Annabel Sandery, *Project Engineer*
Reviewed By:	Peter Sauer, *General Manager SA Networks*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 PROJECT OVERVIEW

This business case relates to a continuation of routine expenditure to provide the appropriate tools and equipment to install, repair and maintain natural gas assets. As existing tools and equipment age, they require replacement in accordance with good business practice.

Keeping plant, operational tools and equipment up to date and in line with advancements in technology, is necessary not only to perform necessary tasks, but to maintain a safe working environment for operating personnel and the public.

The expenditure is required to ensure:

- The provision of a safe working environment for all employees and contractors by providing tools and equipment that are in good working order, fit for purpose and tested/calibrated (as required) to the required standard.

- That the correct tools and equipment are available to maintain the network, including for emergency response. Specialist tools are often required to perform operations such as stoppling, squeeze off, purging and testing without which network activity would not be able to be performed safely or without disruption to consumers and supply.

2 COST AND TIMING

The forecast cost is based on the average of annual expenditure over the current regulatory period, as detailed in Attachment A.

Capex costs are summarised in the table below.

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Small Plant & Equipment	880	880	880	880	880	4,400

3 BACKGROUND

A variety of tools and equipment and small capital items are a necessary part of work to maintain and extend the network. This work includes:

- Excavation
- Restoration
- Location of underground services
- Pressure testing
- Jointing various materials – predominantly polyethylene but includes steel
- Assessing and pinpointing gas escape
- Leak survey
- Maintenance of key network infrastructure including odorising of gas and pressure surveillance.

The type of equipment and tools necessary to adequately perform the work ranges from general excavation equipment to specialised gas detection equipment.

Examples of equipment procured during the current regulatory period include:

- "Selma" – infrared vehicle mounted mobile gas detection equipment
- Hand held infrared detectors to enable detection of gas escapes on services and within buildings (without entering the building)
- Large diameter PE stopple equipment (for emergency response and routine activity)
- PE squeeze-off equipment (for emergency response and routine activity)
- Low noise power generators to alleviate nuisance noise created during 24/7 activity
- Compaction tools
- Concrete cutting devices
- Underground cable location equipment
- Gas meter washing equipment
- Self-contained breathing apparatus
- Hydraulic cast iron pipe crackers.

Due to the volume and variety of tools, plant and equipment in use, continual annual expenditure is required for replacement. As the rate of replacement for such stock cannot be determined accurately (as it depends upon degree of use, harshness of service, technological obsolescence, etc), historical expenditure is commonly used to guide estimates of future expenditure (unless particularly large/new items are forecast). AGN has used an average of 4 years of expenditure as a reasonable and best estimate of annual expenditure over the forecast period.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for the recommended project are:

- Ongoing replacement of existing equipment is required to ensure crews are adequately equipped to perform the work;
- Community expectation is that the equipment is fit for purpose and meets their expectation, i.e. with respect to emissions of noise, dust;
- The use of current technology (e.g. digital read-outs on equipment) ensures efficient work practice and minimises errors in circumstances such as gas readings, pressure readings, etc.;

- Tools/equipment should be such that the manual handling component of tasks is minimised to reduce both the likelihood and consequence of work place injuries, given the high level of manual handling activity involved in the work;
- Tools and equipment wear out through use and periodically require replacement as the equipment becomes unserviceable and ongoing maintenance costs increase;
- Average historical cost is a reasonable indicator of future cost (unless particular items of significant equipment are forecast).

5 RISK ASSESSMENT

The primary risk of not providing the appropriate tools and equipment for the tasks performed is exposing operators, customers and the surrounding environment to health and safety risks. Examples of this include:

- Failure to have appropriate gas detectors to adequately detect and classify leaks could result in fatalities and extensive property damage, especially if gas accumulates under buildings and is exposed to an ignition source.
- Failure to adequately locate underground electricity cables could result in fatality. Many high voltage cables have been hit by operators while undertaking normal activity despite the use of “dial before you dig” plans. Often plans are incorrect or incomplete and appropriate equipment is the last line of defense against electrocution and a major disruption to power supply and telecommunications.
- Failure to protect against manual handling risks can result in significant workplace injuries, especially to backs as evidenced by the history of workplace injuries, primarily to field workers performing seemingly normal duties, including driving, digging, carrying and lifting.
- Failure to provide a safe work environment around confined spaces could lead to fatality through asphyxiation or inadequate retrieval in a medical emergency.

Additionally, there is a risk to efficiency if AGN does not pursue available and emerging technology to address specific network issues and opportunities. Examples are:

- The use of small diameter in-service camera technology to investigate the internal integrity of pipes, to enable preventative maintenance to be performed in preference to, for example, reacting to emergencies involving a large release of gas in relatively close proximity to buildings.
- The use of infrared gas detection equipment has capability to detect gas leaks in buildings without access to the building, by aiming a laser beam through a glass window.
- Laser gas detection technology enables gas survey work to be undertaken more efficiently than a traditional foot survey.
- Cable locating equipment (of the latest technology) is used to improve the accuracy of underground cable locating for both alignment and depth on both public and consumer property, often detecting cables not installed to electrical standards and often embedded in concrete paths surrounding the consumer’s house. This reduces the time taken in manual pot-holing to prove cable location prior to mechanical excavation.

This business case has been assessed as "High” and has been assigned Priority 2. The risk assessment is detailed in Attachment B.

6 OPTIONS

Tools, equipment and non-reticulation items are required and as such there is no alternative. However, AGN continues to look for opportunities to optimise the life of existing plant and equipment and explore options to improve performance by replacing, upgrading or employing new technology as appropriate.

Cost Benefit Analysis

Not applicable.

Capex / Opex Trade-off

Not applicable.

7 JUSTIFICATION

Consistent with the requirements of rule 79 (1)(a) of the National Gas Rules, AGN considers that the capital expenditure to procure tools, plant and equipment is:

- *Prudent - The* expenditure is necessary to ensure there are adequate and appropriate tools, plant and equipment necessary to perform the required functions. The expenditure will allow the continued safe, reliable supply of gas to consumers, services to be maintained and improved and the integrity of the network to be maintained.
- *Efficient -* Cost estimates of expenditure are based on historical spend taking into account the increased use of large diameter polyethylene pipe and emerging issues associated with ageing HDPE which will necessitate innovative and unique risk control methodologies. The estimate allows for maintaining the quantity of plant, equipment and tools at current levels with the expectation that the functionality of some equipment will improve to provide a greater range of applicability and therefore greater risk reduction for the same cost. On that basis AGN considers the expenditure to be efficient.
- *Consistent with accepted industry practice* - The tools and equipment already in use and planned under this expenditure are an essential part of performing the work. Equipment such as large diameter squeeze off, PE stoppling equipment and the like are essential for emergency response and it would be negligent to operate without it.

  Additionally, AGN is aware of its operational impacts on the public and consumers, particularly regarding changed consumer expectation concerning the environment. This has led to, and will continue to lead to, low noise tools such as compressors, generators and drills. The equipment AGN purchases is consistent with community expectations and standard industry practice. To maintain an effective, efficient, safe service, it is fundamental that the operator is equipped with the proper tools and equipment.
- *Necessary to achieve the lowest sustainable cost of delivering Pipeline Services* **-** Tools, plant and equipment is necessary to deliver pipelines services in a safe and cost effective manner.

8 CONSEQUENCES OF NOT PROCEEDING

Failure to provide the operator with the correct quality, quantity and type of tools and equipment would lead to a cessation of network operations.

ATTACHMENT A – Detailed Cost Breakdown

Table 1: Current access arrangement expenditure

Plant, tools, equipment, small capital items.	FY 11-12	FY 12-13	FY 13-14	FY 14-15 f/c	Average
$nom	$1,115,699	$720,856	$854,000	$826,659	$879,304

Table 2: Example of expenditure items in this category - Items Purchased in 2013/14

Item No.	Description	FY 13/14
1	[redacted]	$62,000
2	[redacted]	$1,543
3	[redacted]	$14,100
4	[redacted]	$8,500
5	[redacted]	$6,471
6	[redacted]	$110,000
7	[redacted]	$77,869
8	[redacted]	$61,000
9	[redacted]	$1,670
10	[redacted]	$25,000
11	[redacted]	$2,000
12	[redacted]	$9,000
13	[redacted]	$12,000
14	[redacted]	$71,000
15	[redacted]	$16,000
16	[redacted]	$15,000
17	[redacted]	$32,540
18	[redacted]	$3,280
19	[redacted]	$40,112
20	[redacted]	$17,000
21	[redacted]	$2,760
22	[redacted]	$1,600
23	[redacted]	$4,160
24	[redacted]	$40,360
25	[redacted]	$1,840
26	[redacted]	$90,000
27	[redacted]	$55,000
28	[redacted]	$5,379
29	[redacted]	$11,360

Item No.	Description	FY 13/14
30	[redacted]	$2,085
31	[redacted]	$18,000
32	[redacted]	$1,180
33	[redacted]	$8,376
34	[redacted]	$815
35	[redacted]	$25,000
36	[redacted]	$3,279
	TOTAL	**$854,000**

ATTACHMENT B – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Significant*	*Minor*	*Medium*	*Medium*	*Medium*	*Medium*	*Medium*	
	Risk Level	*High*	*Low*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	***98***
		20	*08*	*14*	*14*	*14*	*14*	*14*	
Residual Risk	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Significant*	*Minor*	*Medium*	*Medium*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Negligible*	*Low*	*Low*	*Low*	*Low*	*Low*	***48***
		13	*05*	*06*	*06*	*06*	*06*	*06*	

Priority		**Priority Description**
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

Australian Gas Networks

APA Group

BUSINESS CASE SA - 31

PROJECT REFERENCE	
Network	AGN – SA
Project No.	SA31
Project Name	Fire safety valves
Budget Category	Capex
Risk and Priority	Moderate, Priority 3
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Spiro Ellul, *Manager Field Operations*
Reviewed By:	Dominic Zappia, *Manager Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	The primary driver for this project is the risk that Australian Gas Networks Limited's (AGN) SA distribution system may contribute to property damage and/or personal injury in the event of a fire (bushfire or house fire) if the emergency shut-off of gas supply to premises cannot occur. The untreated risk has been assessed as Moderate (Priority 3). Work has commenced in the current Access Arrangement Period (AAP) to reduce this risk in bushfire prone areas by installing fire shut-off valves in these areas. The risk could be further reduced by installing fire safety valves in locations where gas meters are located near brush fences and at new and existing customer sites.
Options Considered	Four options were considered to further reduce the risks posed by the distribution system in the event of a bushfire or house fire: • Option 1: Do nothing, which would leave customers located near brush fences and at new and existing customer sites exposed to the risks outlined above. • Option 2: Install fire valves where gas meters are located near brush fences. • Option 3: Option 2 + install fire valves at all new domestic consumer sites and at all existing consumer sites when the meter becomes due for change over as part of the periodic meter change process. • Option 4: Option 3 but rather than retrofitting fire safety valves at all existing consumer sites when the periodic meter change process occurs they would all be retrofitted in the next AAP. Under each of these options, the installation of fire valves in bushfire prone areas is assumed to continue because work on this has already commenced and it has been found to be the best option to reduce the risk to as low as reasonably practicable and in a manner that balances cost and risk.
Option Selected	Option 3 has therefore been selected, because it is the most cost effective way to reduce the risk across the network to as low as reasonably practicable (consistent with Australian Standard AS4645).
Estimated Cost	The forecast capital expenditure over the upcoming AAP is $10.46 million (real $2014/15).
Consistency with the NGR	The installation of the fire safety valves complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services (rule 79(1)(b) and rules 79(2)(c)(i) and (ii)); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (rule 79(1)(a)).
Stakeholder	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and

Engagement	insights to identify four operational themes. This project is considered to be consistent with the *Improve* theme because its implementation will allow AGN to improve network safety. As well as being consistent with the operational theme relating to improving the network, 89% of workshop participants indicated they would be willing to pay for the roll-out of these valves. More information on the stakeholder engagement program and results is provided in Chapter 3 of the AA Information (AAI).

2 Background

Work has commenced in the current AAP to reduce the risk that the SA gas distribution network poses to human health and safety and property damage in the event of a fire. The work to date has involved installing fire valves in bushfire prone areas but there are a number of other areas of the network where the risk to consumers of exacerbated consequential loss (personal and property) in the event of a fire at their residence (or major fire in the vicinity of their residence) could be reduced, which would involve:

- installing fire valves in locations where gas meters are located near brush fences; and
- installing fire valves at all new domestic consumer sites and retrofitting fire valves at all existing consumers when the meter becomes due for change over as part of the periodic meter change (PMC) process.

Reducing these risks to as low as reasonably practicable and in a manner that balances cost and risks is consistent with Australian Standard AS4645 (Gas Distribution Network Management). It is also consistent with practices in Europe where automatic thermal gas shutoffs are required for all gas applications. The European requirements are covered by the following standards:

- DIN 3586 thermo activated safety device for gas applications
- European UNI EN 1775 Standard for indoor gas installations
- European Directive 90/396/CEE certification for durability in mechanical or thermal stress
- German DVGW TRGI 86/96 Standard for thermo activated locking systems on gas heaters, water heaters & domestic gas fittings
- German Standard Muster-Feuerverordnung (FeuVo v. 02/95 – edition 09/97) for thermo activated devices
- Italian UNI 7129 Ed 2001 Standard for fire protection and gas supply line components

Further details on the rationale for this project is provided below.

2.1 Bushfire Prone Areas

Following the recent bush fire at Belair National Park in 2014, where there was the potential for the fire to enter neighbouring suburbs such as Eden Hills, Blackwood and Belair, there is greater awareness of the possible effect of bushfires on utility assets. A fire in built up areas such as these has the potential to melt the aluminium and plastic fittings at the meter inlet, causing a full flow rupture and ignition, resulting in a jet fire. To compound this problem, the gas cannot be turned off at nearby valves because maintenance personnel cannot enter active bushfire zones. The most cost effective way to prevent this occurring is to install a fire safety valve at the meter installation, immediately upstream of the meter.

The fire safety valve is a passive thermal device consisting of a steel body with plug, spring and cartridge system. The outer case has a heat resistance grading of 925 degrees for 60 minutes, so can withstand a bushfire event. When the external temperature reaches 100 degrees centigrade, the alloy that holds the spring and plug melts, and the spring pushes the plug to block the bore of the fitting, hence shutting off the gas supply.

Fire shut-off valves can be retro fitted to existing customers and included as a standard fitting for new services.

GIS and billing records show that there are 14,670 domestic consumer sites within designated high bushfire risk areas. A program for retrofitting bushfire valves in these areas has already commenced, with a total of 4,800 expected to be completed by the end of the current AAP.

2.2 Fire Valves at Brush Fences

Every year in Adelaide a number of fires occur in suburban settings with a consequential impact on the gas meter. Once a meter set is impacted, a jet fire occurs, which increases the damage caused to the nearby infrastructure.

The installation of fire valves at every domestic dwelling where a gas meter is located near a brush fence will eliminate the risks associated with fire damage to the gas meter and associated fittings.

An audit of the entire network is proposed for FY15/16 to identify the sites where gas meters are located near a brush fence. As the exact total is not yet known, an estimate of 800 sites has been made on the basis of the following assumptions:

- Brush fences are predominately found in older "leafy" suburbs of Adelaide. Nominally this represents approximately 80,000 sites (based on suburb analysis of meter installations).
- Of these sites it is estimated that 1 in 100 sites or 800 will require an installation of a fire shut off valve.

2.3 Fire Valves at New and Existing Consumer Premises

Recent stakeholder engagement meetings between AGN and consumers revealed that 89% of consumers are prepared to pay for the roll-out of these valves. This can be achieved most effectively by installing the valves at all new customer sites at the same time as the inlet is installed, and retrofitting valves at existing customer sites at the time when the gas meter is due for periodic changeover.

2.4 Consistency of Project with Stakeholder Expectations

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they:

- valued initiatives that improve community safety; and
- were supportive of initiatives that improved the network where there was a clear benefit to residents and business.

Consistent with the above insights, the installation of fire safety valves will increase the safety of people and properties and is also in keeping with the findings of the willingness to pay study.

3 Risk Assessment

The key risk addressed by this project is the potential for AGN's SA distribution system to contribute to extended damage and/or personal injury in the event of a fire that affects metering facilities.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's risk management and control criteria (see section 3.3 of the Asset Management Plan for further information).

In short, the untreated risk associated with this project has been assessed as "Moderate" and assigned a Priority 3 rating. Further detail on the risk assessment that has been carried out can be found in Attachment B.

4 Key Drivers and Assumptions

The key assumptions and drivers for the project are:

- While a passing fire can cause damage to property, in locations where gas is reticulated, the density of housing is such that homes may not be destroyed. However, if a gas fire eventuates, the total destruction of homes can occur. Current shut-off procedures may not be adequate during times of extreme bushfires because of risk to maintenance personnel safety.
- Fires at brush fences can melt gas inlet fittings and result in jet fires destroying homes.
- High density accommodation in all new suburbs results in gas meters less than one meter away from neighbouring houses and hence a fire at a gas meter at one house will rapidly spread to adjacent buildings.
- This project is consistent with AGN's operational theme of "Improve" network safety and, in particular, the following insights:
  - Customers value initiatives that improve community safety across the network.
  - Customer support improving the network where there is a clear benefit to residents and businesses.
- The project is also consistent with the results of the willingness to pay study, which confirmed that consumers are willing to pay for the widespread installation of fire safety valves

5 Options

The installation of fire valves in bushfire prone areas has commenced in this AAP because it is the best option to reduce the risk to as low as reasonably practicable in a manner that balances cost and risk. Ceasing this program in the next AAP is not considered a feasible option, so no further assessment was carried out on the options associated with this element of the project.

In relation to the other two elements of the project (ie, installing fire valves at brush fences and installing fire valves at new and existing consumer premises), the options include:

- Option 1: Do nothing;

- Option 2: Install fire valves where gas meters are located near brush fences;
- Option 3: Option 2 plus install fire valves at all new domestic consumer sites and at all existing consumer sites when the meter becomes due for change over as part of the periodic meter change process; or
- Option 4: Option 3 but rather than retrofitting fire safety valves at all existing consumer sites when the periodic meter change process occurs they would all be retrofitted in the next AAP.

The costs and benefits of these four options are summarised in the table below.

Costs and benefits of the options in the next AAP

Item	Costs and Risks	Benefits
Option 1: Do Nothing	$1.04 million capex (real $2014/15) Still exposed to risk that distribution system will contribute to extended damage and/or personal injury in brush fence sites and other areas of the network.	Lowest capital cost and. Reduces risk in bushfire prone areas.
Option 2: Install valves at meters near brush fences	$1.12 million capex (real $2014/15) Still exposed to risk that distribution system will contribute to extended damage and/or personal injury in other areas of the network (eg, due to house fire).	Lower capital cost than Option 3 and Option 4. Reduces risk in bushfire prone areas and brush fence sites.
Option 3: Option 2 + new and existing premises (but in line with PMC)	$10.5 million capex in this AAP and $23.7 million capex in subsequent AAPs (real $2014/15) Still exposed to risk that distribution system will contribute to extended damage and/or personal injury at existing premises where fire safety valves have not been installed during the AAP because the metering assets are not due to be replaced.	Lower capital cost than Option 4 because carrying out the fire safety valve installation at the same time that meters are changed allows activities to be combined in one site visit and greater efficiencies to be achieved. Reduces operational, compliance and reputational risk across the network from moderate to low (see Attachment B).
Option 4: Option 3 but all existing premises retrofitted in next AAP	$34.2 million capex (real $2014/15) plus efficiency losses associated with retrofitting all premises in this AAP because activities are no longer combined in one site visit.	Reduces operational, compliance and reputational risk across the network from moderate to low.

Of the options listed above, Option 3 is the most cost effective and efficient way to reduce the risk across the network to as low as reasonably practicable (consistent with Australian Standard Australian Standard AS4645). Option 3 has therefore been selected.

6 Forecast Cost for the Upcoming AAP

The table below provides a summary of the capital expenditure that is forecast to be incurred in the next AAP as a result of the continuation of the installation of fire safety valves in bushfire prone areas and the commencement of work at brush fence locations, new and existing consumer premises, which has been estimated on the basis of the following assumptions:

- Forecast costs have been based on actual current costs of undertaking this work (gas fitter contractor unit rates and actual material costs), with the contractor rates based on the results of a competitive tender current.

- The number of safety valves to be installed assume the following:
  - Continuation of the bushfire prone risk mitigation project to retrofit fire shut off valves at consumer premises that are located within potential bush fire areas (9,900 sites)
  - Installation of fire valves in locations where gas meters are located near brush fences (800 sites).
  - Installation of fire valves at all new domestic consumer sites (8,500 per annum).
  - Retrofit fire valves at all existing consumer sites when the meter becomes due for change over as part of the PMC process (16,000-37,000 per annum).
- The installation of fire safety valves at bush fire and brush fence sites will carried out in 2016/17 because they are considered to be the highest risk sites.
- Retrofitting valves when the gas meter is due for periodic changeover (PMC sites) is assumed to occur in line with the regulatory codes on meter replacement (e.g. 10 years, 15 years), which is why expenditure on the PMC sites varies in each year.

A more detailed cost breakdown can be found in Attachment A.

Capital expenditure forecast excluding overheads ($'000 real $2014/15)

Fire Safety valve installation	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Bushfire Areas	1,040					**1,040**
Brush Fence Locations	84					**84**
New domestic installations	425	425	425	425	425	**2,125**
PMC sites	1,867	1,753	1,555	1,204	833	**7,212**
Total	**3,416**	**2,178**	**1,980**	**1,629**	**1,258**	**10,461**

7 Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the capital expenditure is:

- *Prudent* – The expenditure is necessary in order to maintain and improve the safety of services to customers and the public by ensuring that gas does not flow unimpeded in a house fire situation, and that protection of life and property is maximised. The expenditure is therefore of a nature that would be incurred by a prudent service provider.
- *Efficient* – The work has been spread across a period of years to ensure the program can be managed and supervised in an efficient and controlled manner with estimated labour rates based on current contractor tendered rates. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – Identifying and reducing risks to as low as reasonably practicable is consistent with good industry practice and is reflected in Australian Standard AS4645 (Gas Distribution Network Management). Reducing the risk posed to

consumers during a house fire is also consistent with practices in Europe where automatic thermal gas shutoffs are required for all gas applications.

- *To achieve the lowest sustainable cost of delivering pipeline services* – Reducing risk to as low as reasonably practicable in this case is consistent with the objective of achieving the lowest sustainable cost given the scale of the liability claims that could be made if the distribution network contributes to extended damage and/or personal injury in the event of a fire.

The capital expenditure can therefore be considered consistent with rule 79(1)(a) of the National Gas Rules. The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)), which includes maintaining the security of supply.

ATTACHMENT A – Detailed Cost Breakdown

The table below provides a breakdown of the cost of installing fire safety valves in bushfire prone areas, brush fence locations, new domestic installations and PMC sites, while the second table sets out the number of valves to be replaced in each year of the upcoming AAP.

Fire Valves Capital Expenditure - Excluding Overheads(real $2014/15)

Description	No.	Cost ($)
Bushfire and Brush Fence sites		
[redacted]	9,900	
[redacted]	800	
[redacted]		[redacted]
[redacted]		[redacted]
[redacted]	**10,700**	**$1,123,500**
New homes and PMC		
Total new homes installation	42,500	
Total PMC installations	144,245	
[redacted]		[redacted]
[redacted]		[redacted]
Total New Home and PMC Cost (5 years)	**186,745**	**$9,337,250**
Total Cost		**$10,460,800**

Number of units to be installed Financial Year

FY	16/17	17/18	18/19	19/20	20/21	**Total**
Bushfire	9,900					**9,900**
Brush fences	800					**800**
New homes	8500	8500	8500	8500	8500	**42,500**
PMC	37,347	35,064	31,101	24,077	16,656	**144,245**
Total units	**56,547**	**43,564**	**39,601**	**32,577**	**25,156**	**197,445**

ATTACHMENT – B – Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming no further work is carried out to install fire safety valves (untreated risk), while the bottom panel sets out the residual risks if the valves are installed in the manner described in this business case. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance	Financial Impact	Total Score of Risk Levels
Risk Untreated	Likelihood	Occasional	Occasional	Occasional	Occasional	Occasional	Occasional	Occasional	
	Consequence	Medium	Insignificant	Insignificant	Insignificant	Medium	Medium	Minor	
	Risk Level	Moderate	Low	Low	Low	Moderate	Moderate	Low	
		18	07	07	07	18	18	10	85
Residual Risk	Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	
	Consequence	Medium	Insignificant	Insignificant	Insignificant	Medium	Medium	Minor	
	Risk Level	Low	Negligible	Negligible	Negligible	Low	Low	Negligible	
		06	01	01	01	06	06	03	24

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE SA - 32

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA32
Project Name	Non-compliant meters inside buildings
Budget Category	Capex
Priority	3
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (section 5, Attachment A)
PROJECT APPROVAL	
Prepared By:	Chris Liew, *Integrity Manager*
Reviewed By:	Dominic Zappia, *Manager Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 PROJECT OVERVIEW

As a legacy of historical practices and or building modifications by property owners, there are meters with non-vented regulators located inside buildings. These meters pose the risk of gas escape from a venting regulator, resulting in gas accumulation in an enclosed space, potentially leading to a gas explosion and/or fire with resultant fatalities and/or major damage to property.

It is proposed to rectify 726 non-compliant sites by modifying and or relocating the meter and or inlet services.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Improve theme as it improves network safety.

2 COST AND TIMING

The project is to be carried out over the five years of the next regulatory period to ensure it can be managed effectively. Preparatory work, including site surveys and detailed assessments, will be carried out during FY15/16.

Costs for this project are based on analysis of meter locations maintained in the work management system (Maximo) in which 726 sites have been identified that will require revision of the existing inlet/outlet service pipe or additional vent piping.

Cost estimates have been based on an assessment of the degree of difficulty associated with pipe alterations at each site, with sites rated from 'simple' to 'complex', and associated unit costs based on similar site relocations undertaken elsewhere in the network.

A summary of CAPEX costs by financial year is provided in the table below. Details of volumes, type of relocation and associated unit costs have been provided in Attachment A.

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Total Cost	**281**	**281**	**281**	**281**	**281**	**1,405**

3 BACKGROUND

Australian Gas Distribution Code AS4645.1:2008 recommends that "installation of services under buildings should be avoided" and service pressure regulator relief valves within enclosed rooms must be vented externally or be in a safe location where gas cannot accumulate and find a source of ignition.

A Formal Safety Assessment (FSA)[1] has identified a number of meter sets and services, installed inside buildings, that do not comply with the above code requirements. The non-compliance is a legacy of past practices and or changes made to the building post installation.

Meters operating at high or medium pressures inside buildings can pose a risk to the public of gas escapes (from a venting inlet service regulator) that can accumulate in an enclosed space leading to a fire/explosion with potential catastrophic outcomes.

An analysis of meter location codes within the Maximo Work Management System identified 726 meters, operating at medium or high inlet pressures, located inside buildings (refer to Attachment A for details). This project will see the relocation of these non-compliant meters over a period commensurate with the risk.

There are also a number of potentially non-compliant meters in areas where cast iron and unprotected steel mains replacement is being undertaken. These sites have been excluded from the scope of this project, as identification and rectification of these sites is included in the mains replacement scope of work.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for the recommended project are:

- Meters at medium or high pressures inside buildings pose a risk to public safety and property because of the amount of gas that can rapidly accumulate from a venting regulator;
- Analysis of database records reveals that there are 726 such non-compliant meters within the MP & HP networks; and
- Non-compliant meter locations within mains replacement areas will be rectified as part of that program's scope of work.

[1] AS/NZS4645.1 Formal Safety Assessment SA Distribution Network, 2014

5 RISK ASSESSMENT

The key risk issue is associated with a gas leak from a venting regulator, resulting in the rapid accumulation of gas to the extent that a fire/explosion results. This is a risk to the safety of the public and has the potential for major property damage.

A risk assessment has been carried out using established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on internal risk management and control criteria.

[redacted]

6 OPTIONS

There are two options - either relocate the meter to a safe location, or leave in situ and externally vent the service regulator. Both options require additional or revised pipework (inlet service, outlet service or regulator vent). The course of action will be selected based on lowest cost, once the site has been physically assessed by a gas fitter.

Cost Benefit Analysis

The principal driver for this project is the reduction of risk which cannot be quantified. The relocation or venting of non-compliant metering facilities will avoid potential liability for personal injury and or major building damage in event of a fire or explosion caused by a gas escape.

Capex / Opex Trade-off

There are no Capex/Opex trade off considerations associated with this project.

7 JUSTIFICATION

Consistent with the requirements of rule 79 of the National Gas Rules (NGR), AGN considers that the operating expenditure is:

- *Prudent* **–** the expenditure is necessary in order to maintain and improve the safety of gas services. Failure to address the issue will result in continued risk to public safety and property damage.
- *Efficient* – costs have been based on realistic estimates of the scope of work and experience with similar meter relocations. Unit costs are expected to vary from site to site, however the estimates provided are based on an assessment of complexity associated with the pipe alterations for each site.
- *Consistent with accepted and good industry practice* –it is a distribution code requirement (AS4645) that inlet service, meters and service regulators are placed in a safe location where gas cannot accumulate to hazardous levels; and
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – The capital expenditure is based on the efficient cost required to reduce risks to as low as reasonably practicable. Failure to do so could result in significant financial loss from a gas explosion, and would not be consistent with delivering services at the lowest sustainable cost.

The capital expenditure is justifiable under rule 79(2)(c)(i)(iii) of the NGR as the expenditure is necessary in order to maintain and improve the safety and integrity of services.

8 PROJECT DELIVERY

AGN confirms that it will use a combination of internal and external resources to deliver the recommended project. AGN considers that the delivery of the planned project work is achievable in the timeframe envisaged.

9 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken, there is a risk of fire/explosion incidents that can cause major injury and or property damage as result of a gas escape from meters in non-compliant locations.

ATTACHMENT A – Detailed Cost Breakdown

Cost estimate is based on the following:

- Number of meters: 726
- Cost estimate per meter is based on the following:
    - Complex relocation (15m of pipework required to make compliant) $6,000 each
    - Difficult relocation (10m of pipework required to make compliant) $4,000 each
    - Simple relocation (2m of pipework required to make compliant) $750 each

	Simple $'s	Difficult $'s	Complex $'s
Site preparation visit/planning/customer liaison ($100/hr)	150	500	800
Alteration labour ($250/hr, 2-person team)	500	2,500	4,000
Materials / equipment	100	1,000	1,200
Total	750	4,000	6,000

Item	Meter Location	Sites	Comments	Relocation Difficulty	Unit Cost $'s	Total Cost $'000
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
13	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
14	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
15	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
16	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
	Total	726			Total	1404.5

ATTACHMENT B – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Cost of Risk Level
Risk Untreated	Likelihood	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Major*	*Minor*	*Minor*	*Medium*	*Medium*	*Medium*	*Medium*	
	Risk Level	*High*	*Low*	*Low*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	
		25	*08*	*08*	*14*	*14*	*14*	*14*	*97*
Residual Risk	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Major*	*Minor*	*Minor*	*Medium*	*Medium*	*Medium*	*Medium*	
	Risk Level	*Moderate*	*Negligible*	*Negligible*	*Low*	*Low*	*Low*	*Low*	
		16	*03*	*03*	*6*	*6*	*6*	*6*	*46*

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA33

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA33
Project Name	Upgrade demand customers meter sets
Budget Category	Capex
Priority	3
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	No
PROJECT APPROVAL	
Prepared By:	Chris Liew, *Integrity Manager*
Reviewed By:	Dominic Zappia, *Manager Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 *PROJECT OVERVIEW*

It is proposed to upgrade 24 demand (>10TJ) customer metering sites because of non-compliance with current safety requirements.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Maintain theme as it maintains network safety.

2 *COST AND TIMING*

The work has been spread across the five-year regulatory period to ensure it can be effectively managed.

A summary of Capex costs by financial year is provided in the table below. A detailed cost breakdown has been included in Attachment A. The cost is based on historic costs to upgrade similar facilities.

$000's (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Number of meter upgrades	5	5	5	5	4	
Total Cost	415	415	415	415	332	**1,992**

3 *BACKGROUND*

There are 180 demand (>10TJ) customer metering facilities in the network. These sites meter approximately 70% of the total annual gas delivered.

An initial survey of 15 sites found 2 as having specific issues with the design of the facility and compliance to hazardous zone requirements. A recent survey of 69 sites found 10 as having similar issues.

Changes to the customer's plant and facilities over the years have resulted in these 12 metering facilities now being located in areas not compliant with current standards. Specifically, risks associated with venting gas creating a fire hazard were identified; see Attachment B for some examples. The 2 facilities found in the initial survey are in the process of being rebuilt and repositioned commensurate with current standards.

Based on survey results where about 1 in 7 meters were found to be non-compliant it is estimated that in addition to the 12 known sites a further 14 sites will require a rebuild, including a relocation of up to 5 metres from the existing meter location. Due to the relatively low risk of an incident associated with these meter sets, the work has been scheduled at a rate of 5 meter set rebuilds per year, commencing in 2016/17.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for the recommended project are:

- 24 meter facility rebuilds/relocations will be required to meet current safety standards;
- A combination of internal and external resources will be used to undertake the proposed work.

5 RISK ASSESSMENT

The key issues associated with these metering facilities are:

- Non-compliant metering facilities creating a risk of fire as result of venting relief valves.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria.

This project has been rated as "Moderate" as per APA risk matrix (details in Attachment C) and has been assigned Priority 3.

6 OPTIONS

There are no viable alternatives.

Cost Benefit Analysis

Correcting non-compliant sites will reduce risk of explosion and possible consequential safety issues and risk of damage to public property.

Capex / Opex Trade-off

Substitution between operating and capital expenditure is not applicable in respect of this project.

7 JUSTIFICATION

Consistent with the requirements of rule 79(1)(a)&(b)of the National Gas Rules, AGN considers that the capital expenditure is:

- *Prudent* – the expenditure is necessary in order to reduce the risk posed by non-compliant metering facilities. Reducing these to as low as reasonably practicable is considered prudent.

- *Efficient* – The cost estimates for this project are based on a combination of internal and external resources and the market costs for meter sets and fittings.
- *Consistent with accepted and good industry practice* – The ongoing identification of threats and risks is an operator's obligation as per Australian codes governing gas distribution assets (AS 4645). Reducing safety risks associated with non-compliant facilities is consistent with this objective.
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – The upgrade/rebuild of non-compliant metering facilities will avoid potential liability associated injuries and damage to plant and equipment. The cost to reduce this risk is considered relatively low compared to the cost of a major incident.

AGN considers that the capital expenditure is justifiable under rule 79(2)(c)(i) of the National Gas Rules as the expenditure is necessary in order to improve the safety of services.

8 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken there is a risk of fire incidents that cause major injury and or property damage as result of a gas escape from meter sets in non-compliant locations plus associated liabilities.

ATTACHMENT A – Detailed Cost Breakdown

Cost estimate is based on the following:

- Historical cost of similar projects
- Average cost of a major upgrade $83,000, consisting of:

Materials	**Cost $**
Meter	13600
Regulators	13400
Slam shut	2800
Filter	2200
Valves	7500
Pipe & fittings	2450
Design	1350
Correcting instrument	5600
Telemetry	11100
Inlet & outlet pipe & fittings	1000
TOTAL	**61000**

Labour	**Cost $**
Design	1300
Fabrication, test & paint	3100
Meterset relocation (inlet & outlet)	12000
Installation	1300
Commissioning	1300
Telemetry Inst and test	3000
TOTAL	**22000**

Total cost 5*$83,000 = $415,000 per year for FY16/17 – FY19/20

Total cost 4*$83,000 = $332,000 per year for FY20/21

ATTACHMENT B – Examples non-compliant metering facilities

ATTACHMENT C – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
	Consequence	*Significant*	*Minor*	*Minor*	*Minor*	*Minor*	*Significant*	*Minor*	
	Risk Level	*Moderate*	*Low*	*Low*	*Low*	*Low*	*Moderate*	*Low*	***55***
		15	*05*	*05*	*05*	*05*	*15*	*05*	
Residual Risk	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Significant*	*Minor*	*Minor*	*Minor*	*Minor*	*Significant*	*Minor*	
	Risk Level	*Moderate*	*Negligible*	*Negligible*	*Negligible*	*Negligible*	*Low*	*Negligible*	***36***
		13	*03*	*03*	*03*	*03*	*08*	*03*	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

Australian Gas Networks | APA Group

BUSINESS CASE - SA34

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA34
Project Name	Replacement of obsolete TP regulator station components
Budget Category	Capex
Priority	2
Reference Docs	N/A
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Chris Liew, *Integrity Manager*
Reviewed By:	Dominic Zappia, *Manager Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 PROJECT OVERVIEW

This project is for the replacement of the overpressure shut-off (OPSO) system at 12 transmission pressure (TP) regulator stations and the replacement of the Grove regulators at 5 of these sites.

The existing OPSOs and Grove regulators at these stations are over 40 years old and spares or replacement units are no longer available.

The replacement program will require installation of temporary regulator bypasses at 7 of the 12 stations to maintain gas supply in the downstream network while the work is carried out.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Maintain theme as it maintains network safety and reliability.

2 COST AND TIMING

Costs have been scheduled over a period of time in line with AGN's capacity to undertake the work, and in accordance with an assessed priority for each station (see Table 2, Attachment A). The costs of this project have been based on recent similar work.

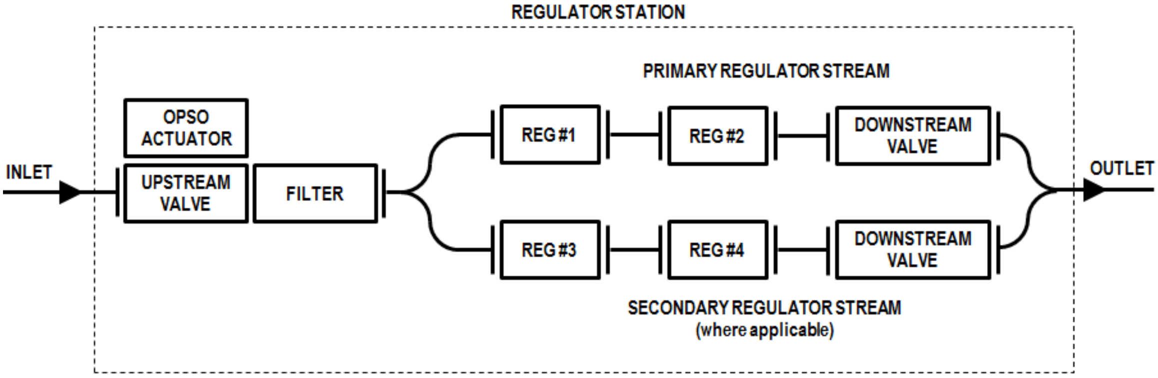
A summary of Capex costs is provided in the table below. A detailed cost breakdown has been included in Attachment A.

$000's (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
OPSO Replacement	26.6	26.6	17.7	17.7	17.7	**106.3**
Grove Regulator Replacement	20.9	41.9	41.9	83.8	0.0	**188.5**
Bypass Installation	60.0	20.0	40.0	20.0	0.0	**140**
Total	**107.5**	**88.5**	**99.6**	**121.5**	**17.7**	**434.8**

3 BACKGROUND

There are 12 TP regulator stations that utilise a pneumatic actuator on the upstream valve for overpressure shut-off (OPSO). The OPSO system protects the network downstream of the regulator station from over-pressurisation in the event of the regulators failing.

The diagram below shows a generic schematic of a SA network TP regulator stations with OPSO.



The OPSO system is the last line of defence against over-pressurisation of the downstream network supplying thousands of consumers. They are normally fitted upstream of regulator runs and actuate automatically to close the upstream valve on high outlet pressure should a regulator stream fail. They are designed to be quick acting to prevent over-pressurisation of the downstream network.

The actuators at 12 sites are between 35 and 45 years old and their condition and reliability is poor. More critically, neither spares nor direct replacements for these actuators are now available on the market and replacement with a new type of OPSO valve is the only option. These components are therefore at the end of their useful life.

The new type of replacement actuators currently available however, do not fit the old-style existing Audco valves and therefore these valves will also have to be replaced.

Five of the 12 regulator stations also utilise old (35-45 years) Grove regulators, which are no longer supported by their manufacturer. Again, neither spare parts nor direct replacement regulators are available on the market and therefore it is prudent to replace them at the same time as the OPSO system is replaced

Seven of the 12 regulator stations cannot be taken off line as they are critical to gas supply in the network. In these cases, a bypass must be installed prior to isolation and blowdown of the regulator station, before the replacement components can be installed.

The scope of work includes:

- Install bypass where required (7 regulator stations);
- Isolate and blowdown regulator station;
- Replace the OPSO system (actuator and regulator upstream valve);
- Replace pipe spool to fit the new valve;
- Replace the Grove regulators (5 regulator stations with 9 regulator streams x 2 regulators per stream);
- Replace pressure sensing lines to fit the new OPSO actuator;

- Replace pressure sensing lines to fit the new regulators (9 regulator stations); and
- Remove bypass and commission station.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for the recommended projects are:

- 12 TP regulator stations are fitted with old OPSO systems for which no spares or replacements are now available;
- Overpressure protection is a critical function in network design and safety;
- New actuators do not fit the old upstream valve, necessitating the replacement of this valve;
- When the old OPSO system is replaced, modification to the pipework will be required;
- Existing Grove regulators at 9 of these sites will also be replaced because spares or replacements are no longer available; and
- Cost and risk are minimised if Grove regulators are replaced concurrently with OPSO replacements.

5 RISK ASSESSMENT

The primary risk is an increased risk to public safety and supply from a regulator failure. The OPSO devices and the Grove regulators cannot be adequately maintained because spares are no longer available, they are at the end of their useful life and are therefore at a higher risk of failing. This can result in loss of supply to thousands of consumers or worse, over pressurisation of the downstream network resulting in a gas leak and fire or explosion.

A risk assessment has been carried out using APA’s established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA’s established risk management and control criteria.

The untreated risk associated with this project has been assessed as "High” given the risk associated with public safety and as such has been assigned Priority 2. Refer to the risk assessment matrix in Attachment B.

6 OPTIONS

Three options were considered:

Option 1 - Replace OPSO system and concurrently replace Grove regulators.

Option 2 - Planned replacement of OPSO and reactive replacement of Grove regulators.

When a Grove regulator fails, install a bypass (where required), blowdown the station, replace the regulator and fabricate new pressure sensing lines on site.

Option 3 - Planned Replacement of Grove Regulators – Reactive replacement of OPSO

When OPSO actuator fails, shut down the OPSO system until a new OPSO system can be prepared (up to 6 months). During the downtime, rely on system redundancy offered by very old active and monitor regulators (and telemetry where installed). If these regulators fail open prior to installation of new OPSO, the downstream network will be over-pressurised.

Cost Benefit Analysis

Option 1 - Total Cost $ 435k. Lowest risk.
Option 2 – Initial Cost $246k + $ 325k reactive replacement of Grove regulators (cost of regulator replacement + by pass). Waiting for failures exposes the network to higher risk.
Option 3 – Total Cost $ 571k (same as Option 2)

Option 1 is chosen as it is the lowest risk solution (as it avoids additional bypass installations).

Capex / Opex Trade-off

There is no opportunity to substitute Opex for Capex. Additional maintenance will not avoid component failure.

There is no material impact on Opex as result of this project. The facilities will be maintained as per current schedules.

7 JUSTIFICATION

Consistent with the requirements of Rule 79 of the National Gas Rules (NGR), AGN considers that the capital expenditure for this project is:

- *Prudent* – the expenditure is necessary in order to improve the safety and security of gas services.
- *Efficient* – The recommended option solution represents the lowest cost solution as detailed in Section 6.
- *Consistent with accepted and good industry practice* – it is consistent with good industry practice to identify risks and take action to address those risks, and to ensure that assets undergo refurbishment or replacement at the end of their asset life.
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – The proposed project is necessary to maintain network safety and reliability. Without the reliable shut-off system there is potential liability for extended damage due to over pressurisation and gas leakage/explosion.

AGN therefore considers that the capital expenditure is justifiable under 79(1)(a) rule and rule 79(2)(c)(i) and (ii) of the National Gas Rules as the expenditure is necessary in order to maintain and improve the safety of services, and maintain the integrity of existing services.

8 PROJECT DELIVERY

The scope of work of the proposed project has been scheduled over a period to ensure it can be effectively managed.

AGN confirms that it will use a combination of internal and external resources to deliver the recommended project.

9 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken in a scheduled manner, the risk is that these critical components of the network will fail to perform their function in service, with the serious consequence of downstream networks being exposed to overpressure. This would have significant impact on the safety of consumers and the public.

ATTACHMENT A – Detailed Cost Breakdown

Table 1- Unit Costs

Item No.	Item	Unit Cost $	Units	Total $'000
1	[redacted]			
2	[redacted]			
3	[redacted]	[redacted]		
4	[redacted]	[redacted]		
5	[redacted]	[redacted]		
6	[redacted]	[redacted]		
7	[redacted]			
8	[redacted]	[redacted]		
9	[redacted]	[redacted]	12	106.3
10	[redacted]			
11	[redacted]			
12	[redacted]	[redacted]		
13	[redacted]	[redacted]		
14	[redacted]	[redacted]		
15	[redacted]			
16	[redacted]	[redacted]		
17	[redacted]	[redacted]	18	188.5
18	[redacted]			
19	[redacted]			
20	[redacted]	[redacted]		
21	[redacted]	[redacted]		
22	[redacted]	[redacted]		
23	[redacted]	[redacted]		
24	[redacted]	[redacted]		
25	[redacted]	[redacted]		
26	[redacted]	[redacted]		
27	[redacted]			
28	[redacted]	[redacted]		
29	[redacted]	[redacted]		
30	[redacted]	[redacted]		
31	[redacted]	[redacted]		
32	[redacted]	[redacted]		
33	[redacted]	[redacted]		
34	[redacted]	[redacted]		
35	[redacted]	[redacted]		
36	[redacted]	[redacted]		
37	[redacted]	[redacted]	7	140
38	**Total**			
39	Materials			254.0
40	Labour			180.8
41	**Grand Total**			434.8

Table 2 - Regulator Station Details & Timing for Replacement

Regulator Station	Bypass required	OPSO Replacement	Regulator Streams	No. Grove Reg Streams	No. Grove Regs	Priority	FY
R103	Yes	Yes	2	2	4	4	17/18
R126	Yes	Yes	2	2	4	4	18/19
R134	No	Yes	2	2	4	5	19/20
R303	Yes	Yes	1	1	2	1	16/17
R313	Yes	Yes	2	2	4	4	19/20
R142	Yes	Yes	1	0	0	2	16/17
R145	No	Yes	1	0	0	3	17/18
R311	Yes	Yes	2	0	0	4	18/19
R325	No	Yes	2	0	0	5	20/21
R328	Yes	Yes	1	0	0	2	16/17
R330	No	Yes	1	0	0	3	17/18
R332	No	Yes	2	0	0	5	20/21
TOTAL	**7**	**12**	**19**	**9**	**18**		

Table 3- Units & Cost Summary

		Units						Cost $'000 (Real 2014/15)					
Item	Unit Cost $k	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total Units	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total Cost
OPSO Replacement	8.9	3	3	2	2	2	12	26.6	26.6	17.7	17.7	17.7	106.3
Regulator Replacement	10.5	2	4	4	8	0	18	20.9	41.9	41.9	83.8	0.0	188.5
Bypass	20.0	3	1	2	1	0	7	60.0	20.0	40.0	20.0	0.0	140.0
Total								107.5	88.5	99.6	121.5	17.7	434.8

ATTACHMENT B – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
	Consequence	*Major*	*Minor*	*Significant*	*Significant*	*Medium*	*Significant*	*Significant*	
	Risk Level	*High*	*Low*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	***98***
		25	*08*	*15*	*15*	*12*	*15*	*15*	
Residual Risk	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Major*	*Minor*	*Significant*	*Significant*	*Medium*	*Significant*	*Significant*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Low*	*Moderate*	*Moderate*	
		16	*03*	*13*	*13*	*06*	*13*	*13*	***77***

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA36

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA36
Project Name	TP Pipelines – Additional Coating Dig Up & Repair
Budget Category	Capex
Risk and Priority	High, Priority 2
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Robin Gray, *Manager Systems Operations*
Reviewed By:	Dominic Zappia, *Manager Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	Recent excavations have revealed significant corrosion on the Transmission Pipelines (TP) in the South Australian gas distribution network under dis-bonded coatings where relatively low Direct Current Voltage Gradient (DCVG) readings were previously considered to represent a minor defect not requiring remediation. These defects are now between 10 and 15 years old and if not addressed could result in a major gas escape if not identified and remediated, which could, in turn, have adverse consequences for human health and safety and result in supply interruptions to thousands of customers. The risk associated with these defects has been assessed as high from a human health and safety perspective (Priority 2).
Options Considered	Two options were considered as part of this business case: • Option 1 – Do nothing. • Option 2 – Excavating and remediating defects that were previously considered 'low priority' and are over 10 years old.
Option Selected	Option 2 has been selected because Option 1 will do nothing to reduce the risk to human health and safety. It is also more cost effective than two other options that were identified but dismissed because they were imprudent (ie, remediating all 'low priority' defects, regardless of age, and modifying the TP network to enable inline inspections to be carried out).
Estimated Cost	The forecast capital expenditure requirement for the excavation and remediation program in the upcoming AA Period (AAP) is $1.069 million (real $2014/15).
Consistency with the NGR	This excavation and remediation program complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services (rules 79(1)(b) and 79(2)(c)(i) and (ii)); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (rule 79(1)(a)).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue to provide a safe and reliable supply of natural gas to our customers. See Chapter 3 of the Access Arrangement Information (AAI) for further detail.

2 Background

The transmission pipelines (TP) in Australian Gas Networks' (AGN) South Australian distribution network (approximately 200 km) are the principal supply to the distribution (HP, MP and LP) networks supplying gas to over 410,000 consumers. These mains operate at a MAOP > 1050 kPa with design, construction, operation & maintenance governed by Australian Standard: AS2885.

The TPs are steel mains, externally coated with either coal tar enamel, PE, fusion bonded epoxy (FBE) or trilaminate and cathodically protected (impressed current or galvanic anode).

Direct Current Voltage Gradient (DCVG) surveys are used to detect coating defects. A breakdown of the coating is detected by an IR rating (measure of current flowing from the pipe to the soil).

Historically only those defects characterised by IR readings greater than, or equal to, 15% were deemed "high priority" and subject to physical investigation, and remediation of the coating. Typically 10 high priority coating defects are examined and repaired each year. Defects characterised by readings less than 15% were deemed "low priority" and not subject to any remediation.[1]

Recent excavations on "low priority" recorded defect sites have uncovered significant corrosion where the coating has dis-bonded from the steel pipe. Water has entered through a small coating defect and created a corrosion cell. The corrosion activity has been masked by the surrounding coating limiting the effectiveness of the CP system. These defects are now between 10 and 15 years old and if not addressed could result in a major gas escape if not identified and remediated, which could, in turn, have adverse consequences for human health and safety and result in supply interruptions to thousands of customers while repair works are carried out.

Corrosion associated with coating dis-bonding would normally be detected using an inline inspection tool (intelligent pig). However, the TPs in the Adelaide distribution system were never constructed to be pigged with numerous plug valves and tight bends preventing the passage of an intelligent pig. With the relatively short lengths and various physical constraints inline inspection is not considered a viable integrity management tool.

To reduce the risk posed by the corrosion of TPs in parts of the network where DCVG readings were previously considered to represent a minor defect, AGN is considering investigating and remediating previously deemed "low priority" defects that are more than 10 years old. There are 55 known "low priority" defects currently between 10 and 15 years old and a further 20 defects that will reach their 10 year anniversary during the next regulatory period. These 75 defects are additional to the 10 "high priority" defects that are normally found from scheduled pipeline DCVG surveys each year.

The excavation and remediation work will involve:

- excavation to expose the coating defect sites;
- removal of pipe coating;
- remediation of pipe corrosion; and
- recoating the pipe and reinstating the surface.

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to maintain our

[1] It is expected that a small coating defect will be contained by the active corrosion protection (CP) system (impressed current or sacrificial anodes). In these cases DCVG surveys will continue to identify the location of the defect and will record the IR which can be compared against the previous reading. If the IR reading was the same or similar then the defect is being controlled by the CP systems and would remain a low priority.

high levels of safety and reliability. Consistent with the above insight, the remediation of corrosion on TPs will enable AGN to continue to provide a safe and reliable supply of natural gas to customers.

3 Risk Assessment

The key risk posed by the corrosion of TPs in parts of the network where DCVG readings were previously considered to represent a minor defect is that it will result in a major gas escape, which could adversely affect public safety and cause an interruption to supply to thousands of customers. If an emergency repair is required, then the pipeline section would need to be isolated, which could, depending on the location, size of leak and time of year, affect supply to several thousand consumers.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. Further detail on the risk assessment that has been carried out can be found in Attachment B.

In short, the untreated risk associated with the corrosion on TPs has been assessed as "High" from a health and safety perspective given the risk associated with a major gas escape, and has been assigned a Priority 2 rating.

4 Key Drivers and Assumptions

The key assumptions and drivers for the recommended project are:

- Undetected corrosion on TPs could lead to a significant gas escape impacting public safety and the security of supply to several thousand consumers.
- Coating inspections at sites with relatively low DCVG readings have shown significant corrosion.
- Lower level DCVG readings that are over 10 years old need to be inspected to avoid significant corrosion on critical supply mains – this will trigger more pipeline dig ups and coating inspections and repairs.
- There are 55 existing "low" priority defects between 10 and 15 years old with a further 20 that will reach their 10 year anniversary during the next AAP.
- The project is consistent with AGN's operational theme of "Maintain" network safety. It specifically relates to the following insights:
  - Customers value AGN's high reliability and want AGN to keep providing the same (as a minimum) service levels.
  - Customers view gas as a reliable source of energy.

5 Options

Two options have been identified to deal with the risks posed by the corrosion of TPs in parts of the network where DCVG readings were previously considered to represent a minor defect:

- Option 1 – Do nothing.
- Option 2 – Digging up and remediating 'low priority' defects over 10 years old.

The costs and benefits associated with options 1 and 2 are summarised in the table below.

Costs and benefits of the options

Item	Option 1 Do Nothing	Option 2 Address 'low priority' defects over 10 years old
Costs/Risks	Risk that corrosion on TPs results in a significant gas leak, which, in turn, results in: • human health and safety being put at risk and AGN being exposed to compensation claims, • more expensive emergency repair costs (eg, a hot tap and bypass in an emergency response to a gas escape can cost approximately $50,000); and • supply being interrupted to thousands of customers (the cost of turning gas on and off ranges from $50-$100 per customer);	$1.069 million (real $2014/15)
Benefits	No upfront costs.	Carrying out the remediation work will: • reduce the risk to human health and safety from high to moderate and operation and compliance risk from moderate to low (see Attachment B); • avoid the need for more expensive emergency repair costs in the event of a gas escape. Hot tapping and bypass can cost around $50,000. With 75 known defects with a high probability that corrosion is active, undertaking planned repair will avoid future reactive repairs of the order of $3.5 million; and • avoid the cost of turning gas off and relighting thousands of customers if a leak occurs. Costs for safe turn off and turn on range from $50 to $100 per customer.

As this table highlights, Option 1 will do nothing to reduce the risk to human health and safety and is not therefore considered a viable option. Option 2 has therefore been selected. It is worth noting in this context that as part of this business case AGN also considered the following options but dismissed them because they were imprudent:

- Investigate all 'low priority' defects regardless of age. This option was dismissed because the lowest priority readings are managed by cathodic protection, which protects the pipe and slows the deterioration rate. It would therefore be imprudent to implement this option.
- Modify the TP network to enable inline inspections to occur and then use inline inspections to detect corrosion and carry out the necessary remediation works. This option was dismissed because the cost of modifying the TP network pipelines is far greater than the cost of digging up the relevant parts of the pipeline and is therefore not as cost effective as Option 2.

6 Forecast Cost for the Upcoming AAP

The table below sets out the forecast cost of carrying out the excavation and remediation work over the upcoming AAP. A more detailed cost breakdown can be found in Attachment A.

Forecast Capital Expenditure ($'000s Real 2014/15 – excluding overheads)

Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
TP Pipeline Excavation & Repair	213.8	213.8	213.8	213.8	213.8	**1,069**

The forecast expenditure has been estimated on the basis of the following assumptions:

- The excavation and remediation work has been spread evenly across the AAP to ensure it can be effectively managed, with 15 additional pipeline excavations and remediations assumed to be carried out each year.
- The contractor and material costs are based on the actual costs that were incurred in 2014/15 carrying out a single exploratory TP pipeline excavation and repair, while the internal costs are based on APA's internal unit rates.

7 Consistency with National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the expenditure being sought for this project is:

- *Prudent* – The expenditure is necessary in order to ensure that the ongoing integrity of the TP is maintained and to ensure that there are no major gas escapes that could impact public safety and reliability of supply, and is of a nature that a prudent service would incur.
- *Efficient* – The excavation and remediation work is the only practical and effective option. It is also the most cost effective option. Engineering assessments and design will be carried out by internal staff and field work will be carried out by external contractors based on competitively tendered rates. The expenditure is therefore of a nature that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – The ongoing effective management of the integrity of the TPs is consistent with Australian Standard AS2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management. Reducing the risks posed by the corrosion of these pipelines to as low as reasonably practicable and in a manner that balances costs and risks is also consistent with this standard.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The excavation and remediation works are necessary to maintain the long term integrity of the TPs. Failure to do so would result in additional expenditure (reactive response to a major gas escape and bringing forward replacement) and shorten the life of the TPs. The project is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services.

The capital expenditure can therefore be viewed as being consistent with rule 79(1)(a) of the National Gas Rules. The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)).

ATTACHMENT A – Detailed Cost Breakdown

The table below provides a detailed breakdown of the forecast set out in Section 6.

$ (Real 2014/15 – excluding overheads)	
Item	**Unit Cost**
[redacted]	$2,250
[redacted]	$500
[redacted]	$1,500
[redacted]	$4,000
[redacted]	$300
[redacted]	$500
[redacted]	$150
[redacted]	$850
[redacted]	$1,500
[redacted]	$2,200
[redacted]	$500
TOTAL COST per joint	$14,250
Proposed number of exploratory excavations and repairs per year	**15**
Total Cost per year	**$213,750**

ATTACHMENT B – Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the remediation work is not carried out on the TP pipelines (untreated risk), while the bottom panel sets out the residual risks if the work is carried out (residual risk). Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance	Financial Impact	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Significant*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*High*	*Low*	*Moderate*	*Low*	*Low*	*Moderate*	*Low*	*80*
		20	*08*	*14*	*08*	*08*	*14*	*08*	
Residual Risk	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Significant*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Negligible*	*Low*	*Negligible*	*Negligible*	*Low*	*Negligible*	*35*
		13	*03*	*06*	*03*	*03*	*06*	*01*	

Priority		Priority Description
Priority 1	(red)	Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2	(orange)	Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3	(yellow)	Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4	(green)	Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA37

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA37
Project Name	Replacement of TP Pipeline Insulation Flanges
Budget Category	Capex
Priority	2
Reference Docs	N/A
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Annabel Sandery, *Project Engineer* and Robin Gray, *Manager Systems Operations*
Reviewed By:	Robin Gray, *Manager Systems Operations*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 PROJECT OVERVIEW

This project addresses the potential risk associated with leaks at joints in Transmission Pressure (TP) mains, which form the backbone of supply to all consumers in the network. The project addresses the risk by planning for the removal and replacement of a number of insulating flanged joints (IFJs) on the transmission mains that are at the end of their useful life and are at risk of leaking.

15 IFJs in high risk locations are planned to be replaced with welded monolithic joints over the next regulatory period. These have been identified to be in locations difficult to respond to in an emergency leak situation.

The scope of work will include:

- Welding on a short stop fitting, hot tapping and stoppling the main;
- Installation of a bypass to maintain supply;
- Isolating and blowing down the section of mains;
- Welding in of the monolithic joint; and
- Associated excavation and reinstatement.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Maintain theme as it maintains network reliability and safety.

2 COST AND TIMING

The scope of work of the project has been spread over a period commensurate with resources and risk.

The costs of this project have been based on the costs of similar works carried out over the last few years.

A summary of Capex is provided in the table below. A detailed cost breakdown is included in Attachment A.

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Materials	8.1	8.1	8.1	8.1	8.1	**40.5**
Labour	161.6	161.6	161.6	161.6	161.6	**808**
Total	**169.7**	**169.7**	**169.7**	**169.7**	**169.7**	**848.5**

3 BACKGROUND

The steel transmission mains in the Adelaide network operate at approximately 1700 kPa and range in size from DN100 to DN300. The mains are protected from corrosion by either coal tar enamel or polyethylene coating along with cathodic protection (impressed current or sacrificial anode).

To operate the cathodic protection (CP) system efficiently the lengths of pipe are divided into sections that are separated by electrically insulated flanged joints (IFJs). This is to allow checks to be done on sizable lengths of pipeline to ensure the CP is working correctly and to allow a quicker identification of any faults. For some decades, the industry standard for isolating steel mains for CP purposes is to use a monolithic joint where possible, this is a welded inline fitting that ensures electrical isolation and eliminates leak points as there are no flanges or screwed fittings on the installation. Prior to monolithic joints, insulated flanges were used, but these were prone to leakage over time. Whenever one of these insulated flanges leaks, the cost to repair under emergency conditions is much higher than under controlled conditions, but more importantly conducting repairs under emergency conditions can place the public and repair personnel at risk, and pose a risk of loss of supply to many thousands of consumers.

Over the past 5 years 6 IFJs have leaked, see attachment B. These types of joints were used on transmission mains laid from the late 1960s to the early 1980s. All mains were laid after this period had monolithic joints welded into the pipeline. The incidents where the IJFs leaked have been repaired using various methods such as, replacing the gasket with the same insulating type gasket, replacing the gasket with a metaflex type gasket, welding in a monolithic joint or a temporary method of encasing the joint with a resin to stop the leak and delay the permanent repair.

It is estimated that there are over 70 insulated flanged joints on transmission mains but not all of these are considered to pose a risk. While it is difficult to identify when or if a gasket is going to leak, where there have been stresses and strains placed on the main (e.g. from work performed on the transmission valve which usually is adjacent to one of these joints), this can point to potential problems at insulating flanges.

In the cases where the larger transmission main repairs to IFJs have had to be repaired, the cost has been significant due to the location of the flanges in confined spaces, cost of the welded fittings for bypasses and the contract and direct labour resources required. As these types of leaks on transmission mains are considered to be a high priority leak under the Standard AS 2885 Section 11, the resources required to repair the leak are usually directed away from normal operational activities, delaying other important activities and thereby also increasing costs elsewhere.

A temporary repair can be made to an insulating flange joint by tightening the flanges and recompressing the gasket however this has proven not to be very successful in the long term. There is also a temporary method of fabricating a metal housing around the flange and injecting resin into the joint to stop the leak. This can be repeated twice before the joint must be cut out and replaced and not every joint can be done this way due to the location of the valve housing.

The insulation gasket is a hard inflexible material which once torqued up and pressurised allows minimal further compression before the material cracks, causing a leak. This is normally the first method to try and stop the leak, although history has shown that joints that have been re-tensioned and do not crack during this work, tend to leak shortly after. There is also the risk of causing a larger leak as there have been incidents where the gasket has cracked during the tightening process causing a larger leak, and placing the safety of operating personnel and nearby public at risk.

One repair method is to eliminate the need for an insulation gasket by replacing the gasket with a more reliable 'metaflex' gasket that can be re torqued many times and has better sealing properties than an insulation gasket. The disadvantage of this method is that the metaflex gasket is not an insulated gasket, therefore extra work and extra cost is incurred to install a monolithic joint on the downstream side of the flanged joint, in order to retain the cathodic isolation of that section of transmission main.

Going forward, it is estimated from previous incidents that 3 leaks per year from IFJs could be expected necessitating an immediate repair (which may involve cutting out the joint, installing a monolithic joint installed using bypasses and stoppling off the main, with an associated risk of possible interruption to supply). Undertaking this type of work on a reactive basis carries higher risk and cost than if a planned program was undertaken.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for this is projects are:

- Insulation gaskets crack due to stress over time. There are currently 70 installed in the transmission network. It is expected that all of these will need to be replaced over the next 20 years;
- Of the 70 there are 15 joints at high risk locations posing a safety risk to either maintenance personnel or to the public and property;
- Risk management, prudency and efficiency requires this work to be completed as a planned task, rather than an emergency task;
- The only long term solution to maintaining insulation joints is the installation of welded monolithic joints, in accordance with good industry practice.

5 RISK ASSESSMENT

The key risk issues addressed by this project are:

- Maintaining the integrity of the existing asset, by proactive replacement rather than reactive repair under emergency conditions; and
- Potential significant gas escapes impacting public safety and reliability of supply.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria.
The untreated risk associated with this project has been assessed as "High" given the risk associated with a major gas escape contributing to a potential fire or explosion (assigned a Priority 2). Refer to the risk assessment matrix in Attachment C.

6 OPTIONS

Two options were considered for this project:

Option 1 - Replace the insulation gaskets with a new insulation gasket. This is slightly lower in cost than option 2 as cutting and welding of the pipe will not be required although a bypass and hot tap and stopple will still need to be installed to affect the repair. The length of time the repair will last is unknown, however it is known that this is not a permanent long term repair. The cost of this option is estimated at $53,900 per repair.

- Materials $ 2,000
- Labour $51,900
- Total $53,900

Option 2 - Replace the insulation gaskets with a metaflex gasket and weld in a monolithic joint downstream of the joint as close as possible to the chamber. Bypasses, hot tapping and stopples will be required. This is slightly more costly due to the cutting of the pipe and welding in the monolithic joint. This work involves increased material cost and a larger excavation. Estimated cost of $56,560 per repair.

- Materials $ 2,700
- Labour $53,860
- Total $56,560

Option 2 is chosen as this is in accordance with current industry practise of using monolithic joints for insulating gas mains for CP purposes. Furthermore, by installing the monolithic joint it eliminates the potential leak of the insulation gasket in the future, and is therefore a permanent repair.

Cost Benefit Analysis

There is no cost benefit applicable to this project.

Capex / Opex Trade-off

Not applicable.

7 JUSTIFICATION

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the capital expenditure is:

- *Prudent* – the expenditure is necessary in order to ensure that the ongoing integrity of the TP mains is maintained and to ensure that there are no major gas escapes that could impact public safety and reliability of supply;
- *Efficient* – AGN considers this proposal as the only practical and effective option. Field work will be carried out by contractors based on competitively tendered rates;
- *Consistent with accepted and good industry practice* – The ongoing effective integrity management of pipelines is a requirement of good industry practice as reflected in AS 2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management. Failure to effectively maintain these pipelines would be contrary to this code; and
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – Failure to maintain the integrity of these pipelines would result in additional expenditure (reactive response to a major gas escape and bringing forward replacement) which is not consistent with the principle of lowest sustainable cost of delivering services.

AGN therefore considers that the capital expenditure is justifiable under 79(1)(b) rule and rule 79(2)(c)(i) and (ii) of the National Gas Rules as the expenditure is necessary in order to maintain and improve the safety and maintain the integrity of services.

8 PROJECT DELIVERY

AGN confirms that program of work will be undertaken by qualified contractors, with supervision by internal personnel.

The replacement of the insulated flanged joints has been spread out over a period to ensure adequate capacity of internal resources to manage the program of work. Maintenance operations have confirmed that they have the capacity to undertake this programme of work.

9 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken, then AGN will continue to be exposed to risks associated with managing high pressure gas leaks with potential public safety and security of supply implications.

ATTACHMENT A – Detailed Cost Breakdown

Replacement of TP Insulating Flange Joints - $'000s						
	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Insulation Joints to be replaced	3	3	3	3	3	15
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Attachment B: Transmission valves that have leaked at IJF's

Nr.	Location
1	Wynn Valve Drive cnr of Bridge Road Wynn Vale
2	Morrow Road corner of Hales drive Lonsdale
3	Old Port Road cnr of Tapleys hill Road Queenstown
4	Cormack Road near Magazine road Wingfield
5	Augusta Street and Rose street Glenelg
6	Corner of Magazine Road Dry Creek opposite Gepps Cross Epic gate station

ATTACHMENT C – Risk Assessment

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance	Financial Impact	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Major*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*High*	*Low*	*Moderate*	*Low*	*Low*	*Moderate*	*Low*	*85*
		25	*08*	*14*	*08*	*08*	*14*	*08*	
Residual Risk	**Likelihood**	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Major*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Negligible*	*Low*	*Negligible*	*Negligible*	*Low*	*Negligible*	*38*
		16	*03*	*06*	*03*	*03*	*06*	*01*	

Priority		**Priority Description**
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE – SA 44

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA44
Project Name	Inlet Data Capture
Budget Category	Opex
Priority	3
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Rob Jones, *Asset Information & Systems Manager*
Reviewed By:	Dominic Zappia, *Manager Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	This project is an expansion of an initiative approved by the AER in the current Access Arrangement (AA) period. It is planned to capture the inlet service details of an additional 9,800 existing Industrial and Commercial (I&C) consumers and about 3,300 multi-dwelling development sites in the next AA period, after the roll-out of AGN's new GIS system, due for completion in 2018/19 (refer to Business Case SA58 for further details). The location records for these sites either do not exist or are not readily available to operations staff and third parties. Without this information, there is a risk of delaying the response of field crews to reported leaks, conducting emergency gas isolation and also an increased risk of third party damage and/or personal injury.
Options Considered	Three options were considered to address the risks outlined above: • Option 1 – Do nothing. • Option 2 – Capture the inlet data for all remaining 9,800 I&C consumers and 3,300 medium to high density multi-dwelling development sites (i.e. highest risk sites only). • Option 3 – Capture the inlet data for all remaining 9,800 I&C consumer sites and *all* multi-dwelling development sites (i.e. including low density sites).
Option Selected	Option 2 was selected because it best balances the risk mitigation of having insufficient geographical information relating to the I&C and highest risk multi-dwelling development sites, with cost-effectiveness.
Estimated Cost	The cost estimate for this project is $1.658 million ($2014/15), spread over the final three years of the next AA period (to coincide with the roll out of the new GIS system). This estimate consists of costs in addition to those incurred for this project in the 2014/15 base year.
Justification of Non-Base Year Cost	This project can be justified as a non-recurrent step change due to the long-term benefit to consumers it provides. In particular, consumers value initiatives that improve community safety across the network and this project lowers the risk posed by a delayed emergency response to gas leaks, due to insufficient geographic information maintained by AGN.

Consistency with the NGR	Capturing the details of the inlet services identified as highest risk is consistent with Rule 91 of the National Gas Rules (NGR) because the project is: • is such that would be incurred by a prudent service provider acting efficiently; • is consistent with accepted good industry practice; and • is necessary to achieve the lowest sustainable cost of providing pipeline services.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Improve* theme because its implementation will enable AGN to improve community safety across the network. Chapter 3 of the AAI provides more information on the stakeholder engagement program conducted by AGN.

2 Background

Geographical information for certain sites within AGN's South Australian network either does not exist or is not readily available to operations staff and third parties. Emergency leak response personnel rely on hand-held mobile devices containing electronic maps to enable a timely and thorough response to reported leaks. Lack of detailed asset location information can:

- Impede the efficiency of routine leak survey activity;
- Increase risk of third party damage; and
- Delay response to reported leaks and emergency gas isolation.

Details of inlet services to I&C and multi-dwelling development sites have not been recorded at all or exist as archived hand drawn sketches not easily accessible. In some instances inlet services are located inside buildings and/or in high density areas (shopping centres, unit developments, and shopping precincts) extending a considerable distance from the main.

In the current AA period, AGN received approval by the AER to commence collecting the location information of inlet services at I&C sites and multi-dwelling developments. As such, AGN has established processes to capture all *new* inlet services at I&C sites and multi-dwelling developments to have this information available for distribution in electronic form. In terms of the risks posed by having insufficient location data of inlet services, these sites are considered to be the highest risk (than compared to domestic inlet services, for example), because the consequence of third party damage and poor emergency response is considered more significant. Typically, details for approximately 400 new sites have been captured per year. Despite this project, there remain 9,800 I&C sites for which there is no inlet service information available.

Medium to high density development sites pose a significant public risk relating to gas escape. Readily available pipework layout records are essential in preventing damage and effectively managing emergency leak responses. Medium to high density development sites account for approximately 14% (3,300) of the total multi-dwelling sites (24,000) within AGN's South Australian network.

In some cases the ownership of I&C and multi-dwelling development inlet services is not clear. This particularly applies to "common" residential estates and shopping centre complexes where trunk services have been laid by the developer in private roadways and common property. To ensure the risks are managed effectively, the ownership (and related liability) of these assets needs to be investigated and resolved. In some cases this will require legal advice.

It is planned to increase the scope of the current project, after the roll-out of the new GIS system due to be implemented in 2018/19. From 2018/19, AGN intends to capture geographical information relating to the inlet services of the remaining 9,800 I&C sites and the 3,300 highest risk multi-dwelling development sites for which there is currently no inlet service information available. In addition, AGN will seek to confirm ownership of each of the I&C sites as the geographical information is collected.

In order to capture data for each inlet service, AGN is required to:

- Arrange site visits to physically locate and record the location of inlet services, valves and meters;
- Create inlet service records within the new geospatial information system (GIS); and
- Publish inlet service records into the operation's mobile mapping system and in response to "Dial Before You Dig" enquiries.

As outlined in Chapter 3 of the Access Arrangement Information, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they value initiatives that improve community safety across the network. Consistent with this insight, capturing the inlet service data of the highest risk inlets is prudent, consistent with good industry practice and will deliver improvements in safety and service levels to customers.

3 Risk Assessment

The key risk associated with this project is public safety. The lack of inlet service information creates a delay in the response time to a gas escape and consequently increases the likelihood of third party damage and/or personal injury in the event of a gas leak.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria.

The untreated risk associated with this project has been assessed as "Moderate" and as such has been assigned Priority 3. Please refer to the risk assessment matrix in Attachment B.

4 Key Drivers and Assumptions

The key assumptions and drivers for the recommended project are listed below:

- Electronic records of major inlet services are required to carry out leak surveys and effectively manage public leak reports;
- The provision of the location details of major inlet services in response to "Dial Before You Dig" enquiries will reduce the risk of third party damage; and
- The ownership and liability of some major inlet services within various complexes (shopping centres, retirement villages etc.) needs to be established to ensure risks are being managed effectively.

5 Options

The three options that have been considered in responding to this risk are outlined below:

- Option 1 – Do nothing. Which consists of continuing the current project of capturing the geographical data of inlet services of *new* I&C and multi-dwelling development sites only.

- Option 2 – Increase the current program of work after the roll-out of the new GIS system, to ensure that all remaining I&C and medium to high density multi-dwelling development inlet services are captured.

- Option 3 – increase the current program of work after the roll-out of the new GIS system, to ensure that all remaining I&C and *all* multi-dwelling development inlet services (including low density developments) are captured.

Of the options listed above, Options 2 and 3 are the only acceptable options due to the risk posed to public safety and the integrity of pipeline services associated with the "do nothing" option. The associated costs and benefits of each of the projects are detailed in the Table below.

Item	Option 2	Option 3
Costs	Project cost: $1.658 million ($2014/15).	Project cost: $4.265 million ($2014/15).
Benefits	Reduction in the risks associated with I&C sites and the highest risk medium to high density multi-dwelling development inlet services.	Greater reduction in the risks associated with the multi-dwelling development sites, than that provided in Option 2. However, it has been assessed that the risks posed by low density multi-dwelling development sites (i.e. those sites not included in Option 2), are low risk. It is estimated that it would cost an additional $2.607 million ($2014/15) to capture the inlet service data for low density multi-dwelling inlet services. The additional reduction in risk associated with capturing the inlet service location information for these sites is not sufficient to offset the additional cost of acquiring this information.

Of Options 2 and 3, Option 2 has been selected based on its cost-effectiveness of reducing the risks associated with the "do nothing" approach, to an acceptable level. Option 3 also reduces the risk associated with this issue, however the cost of Option 3 is considerably higher than Option 2 and is not offset by the additional reduction in risk provided by the project.

6 Forecast Cost for the Upcoming Regulatory Period

AGN is currently undertaking a limited scope of work to capture the location details of some inlet services. The cost of this project contained within the 2014/15 base year, is $107,000 ($2014/15).

The scope of the proposed project consists of (in addition to the program of work currently being undertaken):

- Site visits to each of the 9,800 I&C sites to establish service, service valve and meter locations. A field sketch will be made with the details returned for entry into the GIS;

- Reviewing hardcopy records of 3,300 existing multi-dwelling development sites and transcribing the location details of these inlet services into the GIS. The quality of the hardcopy records varies significantly due to a variety of field data capture methods employed over the years. Based on an examination of a number of records, about 23% of these locations will require a site visit to confirm missing details;

- Publishing the inlet service location details on the mobile electronic mapping system (LatLonGO) used by field maintenance personnel. This will require some minor modifications of the software to enable detailed inlet sketches to be viewed; and

- Publishing inlet service information through the "Dial Before You Dig" electronic mapping services.

- Resolving the ownership of some inlet services located in "common" residential estates and shopping centre complexes

Based on this expanded project scope, the table below provides the costs (in addition to those contained within the base year), AGN intends to incur after the roll-out of the new GIS system in 2018/19.

$'000s (Real 2014/15 – excluding overheads)						
	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Labour			475	475	475	**1,425**
Vehicle Lease			48	48	48	**144**
Software			63	13	13	**89**
Total			**586**	**536**	**536**	**1,658**

The costs of the project are divided into three components:

- Internal labour costs;
- Vehicle lease costs; and
- Costs of GIS software edit licenses (this cost will remain irrespective of the proposed upgrade to the new GIS system).

As evident in the table above, the major cost component of the project is associated with the labour component of capturing the location data for the sites included in the project scope. Because this is the key cost component, AGN has decided to delay ramping up the project until the new GIS system has been implemented, to input the data directly into the new system and avoid possible duplication of costs. This will prevent considerable data rework and redundant software development due to uncertainty surrounding core system functionality. It will ensure labour effort is not wasted in capturing the incorrect metadata and avoid costs associated with the development of software which may become redundant with the introduction of the future GIS system.

As previously specified, the costs detailed in the table above relate only to the resources required in addition to those contained within the base year.

7 Justification of Non-Base Year Costs

As discussed previously, this project has already been approved by the AER in the current AA period. The AER stated, "The work is prudent, consistent with good industry practice and would deliver improvements in safety and service levels to consumers."[1]

Since the AER's decision, AGN has made the prudent decision to defer carrying out the full scope of this project to coincide with the implementation of the new GIS system in 2018/19, in order to avoid costly double-handling of inlet services data.

In the meantime, AGN has collected location data of all *new* I&C customer inlet services as the incremental cost of field crews collecting this information whilst they are already on site, is considerably less than the cost of field crews attending the site at a later date, specifically to collect the data.

The project can be justified as a non-recurrent step change because it is in the long-term interests of consumers. In particular:

- AGN does not currently have sufficient information to enable emergency crews to respond efficiently to reported leaks. As such, AGN is at risk of being held liable if damage is caused to third parties that could have been avoided if appropriate records existed. Should AGN be obligated to provide compensation to third parties, these costs will ultimately be passed on to consumers. It is therefore in the long-term interests of consumers to ensure that AGN mitigates this risk effectively and avoidable costs are not passed on to consumers.

- Consumers place value on initiatives that improve community safety across the network. In addition, it is good industry practice to ensure that accurate records of utilities' assets are available through the "Dial Before You Dig" service. This project, therefore, provides a long-term benefit to customers at the lowest cost available. AGN considers that the proposed

[1] AER, "Draft Decision: Envestra Ltd Access Arrangement Proposal for the SA Gas Network 1 July 2011 – 30 June 2016", February 2011, pg. 161.

approach to this project ensures that the cost of providing this service to consumers is efficient.

8 Consistency with the National Gas Rules

Consistent with the requirements of Rule 91 of the National Gas Rules, AGN considers that the operating expenditure to address the current information gap regarding major inlet services in AGN's electronic mapping system is:

- *Prudent* – The expenditure is necessary in order to improve the safety of services to I&C and multi-dwelling development customers. The availability of inlet service details on the current electronic mapping system will enable:
  - Effective management of risks associated with the lack of geographical information on current inlet services (as detailed in Attachment B);
  - Emergency response personnel to locate and isolate the primary supply to I&C and multi-dwelling development sites in a more timely manner;
  - Efficient and effective leak surveys of I&C and multi-dwelling development services to be undertaken; and
  - Effective communication of the location of major inlet services to third parties using the "Dial Before You Dig" service.
- *Efficient* – This project was selected on the basis of the following factors and for these reasons the operating expenditure is considered efficient:
  - The total number of inlet data capture sites has been optimised to target the highest risk sites where the consequence of poor response and or third party damage is more significant. The costs of the project are based on actual GIS software edit licence cost, contractor costs equivalent to internal labour costs used within APA's Planning Department for similar data capture and GIS records updating and project management costs.
- *Consistent with accepted and good industry practice* – This project addresses the gap between AGN SA and other AGN sites within Australia (such as AGN Queensland where a similar project is already underway) and other utilities in South Australia. For example:
  - SA Water already provides both sewer and water service connection locations;
  - SA Power Networks provides electricity service lines locations; and
  - Telstra provides service connection locations.
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – The deferral of the project until after the implementation of the new GIS ensures there is no costly double-handling of the data. The project also mitigates the risk of potential damage and exposure to potential liability for damage, which is in line with delivering a sustainable service at the lowest cost.

ATTACHMENT A - Detailed Cost Breakdown

<u>Option 2</u>

The cost of this project has been based on:

- The use of 4 additional full time employees to undertake site visits and 1 full time employee for back office data capture.
- Resource costs based on $95,000 ($2014/15) per year (equivalent to an Internal Class 4 Technical Officer used within the Planning and Engineering Department used for similar data capture and GIS records updating).
- The cost of one additional GIS licence.
- 4 x Lease vehicles for site visits.
- Software development to enable field operatives to view detailed inlet service sketches within the mobile mapping product (LatLonGO). The cost estimate is based on estimated hours to code and rates as per WeDoIt's current Consultancy Services Agreement and is not expected to change in response to the roll-out of the new GIS system.

$'000s (Real 2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
[redacted]			475	475	475	**1,425**
[redacted]			13	13	13	**39**
[redacted]			48	48	48	**144**
[redacted]			50	-	-	**50**
Total			**586**	**536**	**536**	**1,658**

Type	Count	Average Capture Rate hour/site	Total Hrs
I&C Sites			
Demand > 10 TJ Customers	158	[redacted]	[redacted]
I&C	9638	[redacted]	[redacted]
Shop Precincts	35	[redacted]	[redacted]
Total	9,831		[redacted]
Multi- Unit Development Sites			
Lifestyle Villages	169	[redacted]	[redacted]
High density Unit Dev	314	[redacted]	[redacted]
Medium density Unit Dev	2,814	[redacted]	[redacted]
Total Multi Unit Sites	3,297		[redacted]
Grand Total	13,128	[redacted]	[redacted]
Resource Requirements			
Available Working Hours per year 4 weeks holiday, 10 days public holidays, 5 days personal leave	1710		
Total FTE Requirements over 3 years	6.4		

Option 3

Costs for this option are based on the same cost estimates used for Option 2. This option includes capturing inlet service data for Option 2 and an additional 22,688 low density multi-dwelling developments.

The cost build-up for this Option is detailed below:

$'000s (Real 2014/15 – excluding overheads)						
Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]
Total			1455	1405	1405	4265

ATTACHMENT B - Risk Assessment

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance	Financial Impact	Total Score of Risk Levels
Risk Untreated	Likelihood	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Medium*	*Minor*	*Minor*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Low*	*Low*	*Low*	*Low*	*Moderate*	*Low*	
		14	*08*	*08*	*08*	*08*	*14*	*08*	*68*
Residual Risk	Likelihood	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
	Consequence	*Medium*	*Minor*	*Minor*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Low*	*Low*	*Low*	*Low*	*Low*	*Low*	
		12	*05*	*05*	*05*	*05*	*06*	*05*	*42*

Priority		Priority Description
Priority 1	(red)	Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2	(orange)	Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3	(yellow)	Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4	(green)	Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA45

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA45
Project Name	Non-Compliant Domestic Regulator Replacement
Budget Category	Capex
Priority	2
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Robin Gray, *Manager Systems Operations*
Reviewed By:	Robin Gray, *Manager Systems Operations*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 PROJECT OVERVIEW

This project is a continuation of AGN's program in high pressure (HP) networks of replacing non-compliant domestic inlet service regulators that do not have adequate relief valve capacity.

It is planned to survey the remaining 160,000 HP domestic consumer meter sites and replace non-compliant regulator installations. It is estimated that approximately 9,600 domestic regulators will require replacement over the next regulatory period.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Maintain theme as it maintains network safety.

2 COST AND TIMING

Costs for this project are based on:

- Use of external resources at contract rates;
- Using meter readers to carry out a survey; and
- Maintaining the current regulator configuration types.

The following table provides a summary of forecast costs of the project. A detailed cost breakdown has been provided in Attachment A.

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Materials	58	124.7	124.7	124.7	124.7	**557**
Labour	130.7	60.9	60.9	60.9	60.9	**374**
Total	**189**	**186**	**186**	**186**	**186**	**931**

3 BACKGROUND

Over the last 40 years various types of domestic regulators, predominately the Email 104, Email 102 and the Reliance 1213B, have been installed at domestic premises to regulate the supply of gas to the consumer.

These regulators require:

- A 1/4" orifice when connected to a medium pressure (MP) network (operating at nominally 100 kPa);
- A smaller 3/16" orifice when connected to a HP network (operating at nominally 350 kPa).

Apart from the "fine print" on the regulator name plate, there is no way to differentiate between regulators with different orifice sizes as the body shape and size of each type of regulator is the same. This has led to a number of regulators with the incorrect orifice size installed in HP networks.

While under normal operating conditions, a 1/4" orifice regulator installed in a HP network will provide adequate pressure regulation, it is possible that in emergency relief mode the downstream pressure (within the household pipework) could rise above the recommended 5 kPa and maximum safe pressure of 7 kPa (the rating of downstream appliance regulators). While it is unlikely, the potential exists for gas to leak into the dwelling with a subsequent risk of fire or explosion.

It is a code requirement (AS 4645 – Section J) that service regulators have capacity to prevent pressures from exceeding the maximum rating of downstream facilities. In the case of domestic installations this is 7 kPa, the maximum rating of the appliance regulator.

There are about 208,000 regulators installed in the HP networks. A survey of 10,000 sites revealed 6% of these to be non-compliant, equivalent to a total of about 12,500 regulators.

About 48,000 sites are expected to be surveyed and 2,900 non-compliant regulators replaced during the current regulatory period. The remaining 160,000 sites remain to be surveyed, with an estimated 9,600 regulators to be scheduled for replacement over the next regulatory period.

Based on surveys undertaken to date, about 40% of installations utilize the AMPY inline configuration regulator. The remaining regulators are AMPY 300 series right angle configuration. The former are no longer the standard used for domestic installations. However replacement of these on a like for like basis is recommended to avoid expensive alteration to the inlet service. Service alteration could cost several hundred dollars versus a premium of about $45 for an inline regulator over the standard AMPY regulator.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for the recommended project are:

- There are regulators operating in the high pressure network with insufficient relief capacity with potential for downstream pressure to exceed the recommended maximum;
- Based on a recent survey approximately 6% of the total 208,000 HP regulators have inadequate relief capacity;
- Regulator replacements at 48,000 sites will be completed during the current regulatory period leaving an estimated 160,000 sites to be completed;
- Inline service regulators will be replaced on a like for like basis so that alterations to the service is avoided; and
- The survey component of this project will be undertaken by existing meter reading contractors familiar with customer liaison and safety procedures.

5 RISK ASSESSMENT

The primary risk of inadequate non-compliant domestic regulators is that if there is an abnormal situation (regulator venting), excessive pressure in the downstream piping may result in gas leaking into a dwelling with the potential for serious consequences.

The untreated risk has been assessed as "High", based on the potential impact to public health and safety, and as such has been assigned Priority 2. Refer to the risk assessment matrix in Attachment B.

6 OPTIONS

There are no alternatives to rectifying the situation.

Cost Benefit Analysis

The primary driver for this project is the reduction of risk associated with exceeding recommended pressure downstream of the meter for which a tangible cost benefit is difficult to define. Should there be a major incident associated with gas in building caused by a venting regulator there would significant liability costs associated with such an event.

Capex / Opex Trade-off

Substitution of Capex for Opex is not applicable for this project. The additional Capex does not impact Opex.

7 JUSTIFICATION

Consistent with the requirements of Rule 79(1) (a) of the National Gas Rules, AGN considers that the capital and operating expenditure is:

- *Prudent* – the expenditure is necessary in order to improve the safety of services. The identification and replacement of regulators will reduce the risk of gas in buildings.
- *Efficient* – The cost estimates for this project are based on the market price for replacement regulators, current internal labour rates and meter reading charge rates. The use of meter readers provides a cost effective means of gathering information on the installed regulators and retaining the inlet service configuration is a lower cost solution.
- *In accordance with good industry practices* – AS 4645 requires that service regulators prevent pressures from exceeding the maximum rating of downstream facilities. In the case of domestic installations this is 7 kPa (appliance regulator)..
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – This project seeks to avoid the potential for major injuries and or damage to buildings at a relatively low cost consistent with delivering a long term sustainable service.

AGN therefore considers that the capital expenditure is justifiable under 79(1) (a) rule and rule 79(2)(c)(i),(ii) and (iii) of the National Gas Rules as the expenditure is necessary in order to maintain and improve; safety of services; integrity of existing services and regulatory compliance.

8 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken, AGN will be exposed to risks associated with non-compliant domestic regulator installations that could result in liability for property damage and or personal injury.

ATTACHMENT A – Detailed Cost Breakdown

Cost Estimate $'000 – Non Compliant Regulator Replacement						
	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
[redacted]	[redacted]					[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capex	**187.7**	**185.6**	**185.6**	**185.6**	**185.6**	**931.2**

ATTACHMENT B – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Unlikely*	*N/A*	*Unlikely*	*N/A*	*Unlikely*	*Unlikely*	*Unlikely*	
	Consequence	*Major*	*N/A*	*Insignificant*	*N/A*	*Minor*	*Medium*	*Medium*	
	Risk Level	*High*		*Negligible*		*Low*	*Moderate*	*Moderate*	**52**
		21		*02*		*05*	*12*	*12*	
Residual Risk	**Likelihood**	*Rare*	*N/A*	*Rare*	*N/A*	*Rare*	*Rare*	*Rare*	
	Consequence	*Major*	*N/A*	*Insignificant*	*N/A*	*Minor*	*Medium*	*Medium*	
	Risk Level	*Moderate*		*Negligible*		*Negligible*	*Low*	*Low*	**32**
		16		*01*		*03*	*06*	*06*	

Priority		**Priority Description**
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA49

PROJECT REFERENCE	
Network	AGN – SA
Project No.	SA49
Project Name	DCVG survey, excavations and remediation of distribution mains
Budget Category	Capex
Risk and Priority	Moderate, Priority 3
Reference Docs	N/A
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Mujibur Rahman, *Corrosion Engineer*
Reviewed By:	Chris Liew, *Integrity Manager*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	The 200 km of steel distribution trunk mains in Australian Gas Networks' (AGN) SA distribution network have never been subject to a Direct Current Voltage Gradient (DCVG) survey.[1] Based on defects and associated corrosion found on steel transmission trunk mains, similar levels of active corrosion are expected to exist on the distribution trunk mains. If left unchecked, this corrosion could result in major gas escapes, which would require emergency repairs and/or replacement and could also result in the supply of gas to up to a thousand customers being interrupted. To deal with this risk, AGN has commenced a DCVG survey and remediation program. By the end of the current Access Arrangement Period (AAP), 30 km of the distribution mains will have been surveyed, leaving another 170 km to be surveyed and repaired, where necessary. The untreated risks associated with corrosion on the distribution mains has been rated as Moderate (Priority 3).
Options Considered	Two options were considered as part of this business case: • **Option 1** - Conduct a DCVG survey on the remaining 170 km of distribution trunk mains that is yet to be surveyed and, where necessary, carry out remediation works (planned coating defect identification and remediation program) at a cost of $1.224 million (real $2014/15); or • **Option 2** – Do not conduct a DCVG survey and just deal with any effects of corrosion as they arise through a reactive repair and replacement program at an estimated cost of $2.5 million (real $2014/15) plus the cost of managing any gas outage.
Option Selected	Option 1 was selected because it reduces the risks associated with the corrosion in a more cost effective manner than Option 2 (ie, because it avoids the additional costs of emergency repairs and replacements and the costs of turning gas off and on if sections of the pipeline need to be isolated to manage a gas escape).
Estimated Cost	The forecast capital expenditure for the replacement program in the next AAP is $1.224 million (real $2014/15).
Consistency with the NGR	The survey and remediation of the distribution trunk mains complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services (rule 79(1)(b) and rules 79(2)(c)(i) and (ii)); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (rule 79(1)(a)).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue to provide a safe and reliable supply of natural gas to our customers. More information on our stakeholder engagement program and results is provided in Chapter 3 of the Access Arrangement Information (AAI).

1 DCVG surveys are used to locate coating defects on buried pipelines.

2 Background

Steel trunk mains form the primary gas distribution network in Australian Gas Network's (AGN) South Australian gas network and are used to deliver gas to over 410,000 consumers. There are approximately 400 km of steel trunk mains in the SA network, of which approximately:

- 200 km are transmission mains nominally operating at 1650 kPa; and
- 200 km are distribution trunk mains nominally operating at 350 kPa.

All of these steel trunk mains are about 30 years old and range in size from DN100 to DN400. They are protected from corrosion by high density polyethylene external coating with heat shrink sleeves, or polyethylene tape wrap at field joints along with Cathodic Protection (CP) (anode or impressed current).

The transmission trunk mains are subject to Australian Standard AS2885, which requires the integrity of external protective coatings to be assessed using DCVG surveys. Distribution trunk mains, however, are not subject to this standard and so have never been subject to the DCVG survey. Given that substantial coating defects, with associated corrosion, have been found on the transmission trunk mains and the same type of coating has been used on distribution trunk mains and the vintage of the mains is similar, the corrosion issues observed on the transmission mains are expected to be present on the distribution trunk mains. If left unchecked, the corrosion could result in major gas escapes requiring emergency repairs and/or replacement and a supply interruption.

Given this risk, AGN has started to carry out DCVG surveys on the distribution trunk mains. In total 30km of distribution trunk main will be surveyed and repaired during FY14/15 and FY15/16 and the remaining 170 km (predominantly located in the Adelaide metro area) will be surveyed in the next AAP. These surveys will allow the condition of the distribution trunk mains in the network to be assessed any repairs considered necessary to maintain asset integrity and reduce risks of supply loss and/or safety incidents, to be carried out.

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to maintain our high levels safety and reliability. Consistent with the above insight, the DCVG survey and remediation work will enable AGN to continue to provide a safe and reliable supply of natural gas to customers.

3 Risk Assessment

The key risks associated with corrosion on the distribution trunk mains is potential for a major gas escape to occur. If this occurs it could adversely affect public safety and result in the loss of supply to up to a thousand consumers if the mains need to be isolated for emergency repairs. It would also result in more expensive remediation works.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria (see section 3.3 of the Asset Management Plan for further information).

In short, the untreated risk associated with this project has been assessed as "Moderate" given the risk associated with supply loss to several thousand consumers and as such has been assigned Priority 3 rating. Further detail on the risk assessment that has been carried out can be found in Attachment B.

4 Key Drivers and Assumptions

The key drivers and assumptions for this project are as follows:

- The distribution trunk mains are expected to have similar corrosion and coating defects to those found on the transmission trunk mains, which are coated with a similar material and are of a similar vintage to the distribution mains but operating at a higher pressure.
- Safety incidents may occur as a result of loss of integrity.
- Emergency repairs may result in large scale outages.
- DCVG surveys are effective in detecting major coating defects.
- Early detection and repair of coating defects will maintain asset integrity and minimise repair costs.
- Based on previous DCVG surveys, it is estimated that one defect will require excavation and assessment in every 2km of mains surveyed.
- This project is consistent with AGN's operational theme of "Maintain" network safety. It specifically relates to the following insights:
  - Customers value AGN's high reliability and want AGN to keep providing the same (as a minimum) service levels.
  - Customers view gas as a reliable source of energy.

5 Options

Two options were considered to deal with the risks outlined above:

- **Option 1** - Conduct a DCVG survey on the remaining 170 km of distribution trunk mains that have not yet been surveyed and, where necessary, carry out remediation works (planned coating defect identification and remediation program); or
- **Option 2 –** Do not conduct a DCVG survey and just deal with any effects of corrosion as they arise through a reactive repair and replacement program.

The costs and benefits associated with these two options are summarised in the table below.

Costs and benefits of the options

Item	Option 1 Planned defect identification and remediation program	Option 2 Reactive repair and replacement program
Costs/Risks	$1.224 million (real $2014/15) (see section 6 for further detail on this estimate)	$2.5 million (real $2014/15) for remediation works[2] plus $0.1-$0.3 million to manage the gas outage (turn off and turn on). If a planned remediation program is not carried out the corrosion will inevitably result in gas leaks, which require more expensive emergency repair and/or piecemeal replacement of the pipes and supply interruption.
Benefits	Carrying out the DCVG survey and planned remediation program will ensure the integrity of the assets is maintained and avoid: • the additional cost of emergency repairs and the replacement of assets before the end of their technical lives; and • the cost of managing a gas outage (ie, turn off and turn on). This option also reduces the risk to health and safety, operational risk and compliance risk from moderate to low (see Attachment B).	No upfront costs.

As this table highlights, Option 1 reduces the risks associated with the corrosion in a more cost effective manner than Option 2 because it avoids the additional costs of emergency repairs and replacements and the costs of turning gas off and on if sections of the pipeline need to be isolated to manage a gas escape. Option 1 has therefore been chosen, and it is considered consistent with the action that a prudent operator would take.

6 Forecast Cost for the Upcoming AAP

The table below provides a summary of the capital expenditure that is forecast to be incurred in the next AAP when carrying out the DCVG survey and remediation works. This forecast has been based on the following assumptions:

- DCVG - the DCVG survey is assumed to be carried out in 2016/17. The cost of carrying out this survey ($1,000 per kilometre) is based on the costs that were incurred carrying out similar DCVG surveys on distribution trunk mains in 2013/14 and 2014/15.
- Excavation and repair work – this work is assumed to be carried out across the next AAP, commensurate with the resources available and risk, and to ensure it can be effectively managed across this and other projects that require excavation and pipeline repairs. The cost of carrying out this work is based on the actual cost of carrying out similar activities to-date. It has also been assumed, based on the surveys carried out in 2013/14 and 2014/15 where one major defect was detected every 2 km, that 85 defect excavations and coating repairs will be required

[2] Based on previous surveys carried out in 2013/14 and 2014/15 where one major defect has been detected every 2 km, it is estimated that 85 reactive repairs may be required in the future, which amongst other things, would involve pressure control, excavation of leak and repair clamp fitting and possible welding fittings. Depending on the location and time of year, stopple and bypass may also be required to maintain supply. Repairs costs under this option are estimated to range from of the order of $20,000-$30,000 per repair and piecemeal replacement $30,000-$50,000. If it is assumed that it costs around $30,000 per reactive repair then the cost of this option would be $2.5 million.

across the 170 km of mains still left to survey during the AAP and 17 excavations will be carried out each year.

- The project will be carried out by a combination of external contractors (for the DCVG survey, defect excavations and repairs) and internal resources (for supervision).

The forecast cost of carrying out this work is higher than similar work on transmission mains because the presence of many branches and services on the distribution mains makes the task considerably more difficult and time consuming. For the DCVG survey, surveying distribution mains is more complex and time consuming because of inadequate test points, unsuitable test point wiring and limited section isolation.

Capital expenditure forecast excluding overheads ($'000 real $2014/15)

Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
DCVG survey	170					**170**
Defect excavation and repair	210.8	210.8	210.8	210.8	210.8	**1,054**
Total	**380.8**	**210.8**	**210.8**	**210.8**	**210.8**	**1,224**

A more detailed cost breakdown is provided in Attachment A.

7 Consistency with National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the proposed expenditure is:

- *Prudent* – The expenditure is necessary in order to improve the safety and reliability of services and is of a nature that a prudent service provider would incur. Undetected corrosion of major trunk mains could result in a significant gas escape impacting public safety and security of supply.
- *Efficient* – A planned proactive identification and repair of coating defects is the most cost effective option for dealing with the risk of corrosion on distribution trunk mains. The cost estimates are based on the costs of similar work carried out previously using external contractors selected through competitive tenders. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur
- *Consistent with accepted and good industry practice* – Addressing the risks associated with integrity of major trunk mains is consistent with good and prudent asset management.
- *To achieve the lowest sustainable cost of delivering pipeline services* – Identifying and repairing asset defects will reduce risk of system failure and avoid repair and replacement costs due to corrosion in the long term. The survey and remediation work is therefore consistent with the objective of achieving the lowest sustainable cost of delivery.

It follows from these points that the capital expenditure is consistent with rule 79(1)(a) of the National Gas Rules. The proposed capital expenditure is also consistent with rule 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)), which includes maintaining the security of supply.

ATTACHMENT A - Detailed Cost Breakdown

A detailed breakdown of the forecast cost estimate set out in section 6 is provided below.

Cost estimate is based on the following:

DCVG

[redacted]

TOTAL COST OF DCVG SURVEY **$170,000**

DEFECT EXCAVATION & REPAIR

[redacted]

TOTAL COST per excavation & repair **$12,400**

- In 2014 and 2015, two DCVG surveys undertaken on a total of 12km medium pressure main found on average 1 major defect per 2km. On this basis, the number of defects for 170km of mains is estimated to be 85. This equates to 17 excavations and repair per year over a 5 year period.
- Cost per year for defect excavation and repair (17 x $12,400) = **$210,800**

ATTACHMENT B – Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the DCVG survey and remediation works are not carried out (untreated risk), while the bottom panel sets out the residual risks if the works are carried out (residual risk). Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	Possible	Possible	Unlikely	Possible	Possible	Possible	Possible	
	Consequence	Medium	Insignificant	Medium	Minor	Minor	Medium	Minor	
	Risk Level	Moderate	Negligible	Moderate	Low	Low	Moderate	Low	68
		14	04	12	08	08	14	08	
Residual Risk	Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	
	Consequence	Medium	Insignificant	Medium	Minor	Minor	Medium	Minor	
	Risk Level	Low	Negligible	Low	Negligible	Negligible	Low	Negligible	28
		06	01	06	03	03	06	03	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA52

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA52
Project Name	HDPE camera Investigation and repair
Budget Category	Capex
Risk and Priority	High, Priority 2
Reference Docs	N/A
Confidentiality Claim	Yes
PROJECT APPROVAL	
Prepared By:	Chris Liew, *Integrity Manager*
Reviewed By:	Dominic Zappia, *Manager, Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	[redacted] 1. Carry out a targeted replacement of HDPE mains (see 2015 SA Mains Replacement Plan); 2. Carry out in-line HDPE camera inspections; 3. Install HDPE ground vents (see business case SA56); and 4. Develop a comprehensive integrity management plan for HDPE pipes, which includes developing an evidence based integrity management strategy aimed at optimising maintenance and replacement programs associated with HDPE mains (see business case SA54). The second of these actions is the subject of this business case. The untreated risk associated with HDPE pipes is High (Priority 2).
Options Considered	[redacted]
Option Selected	[redacted]
Estimated Cost	The forecast capital expenditure for the HDPE in-line camera inspections and repair program is $11.58 million (real $2014/15).

Consistency with the NGR	The inspection and repair of these assets complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services (rule 79(1)(b) - rules 79(2)(c)(i) and (ii)); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (rule 79(1)(a)).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue to provide a safe and reliable supply of natural gas to our customers. See Chapter 3 of the Access Arrangement Information (AAI) for further detail.

2 *Background*

Class 575 (SDR 9.9) and Class 250 (SDR 17.6) high density polyethylene (HDPE) distribution mains were installed in the South Australian gas distribution network between the early 1970s until the late 1990s. Since the late 1990s, a new generation of medium density polyethylene (MDPE) has been used. The table below summarises the length of HDPE mains by pressure regime within the Adelaide metropolitan and regional networks as at the end of June 2014.

	High		Medium		Low		
Location	Class 250	Class 575	Class 250	Class 575	Class 250	Class 575	Grand Total
Adelaide Metro	0	850	311	459	242	83	1945
Regional	0	110	2	50	11	1	174
Grand Total	0	960	312	509	253	84	2119

[redacted]

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2.1 Project scope

To complement the replacement program outlined above, AGN plans to undertake a comprehensive internal pipe inspection and repair program using camera inspection of the remaining 1,330 km of Class 575 mains. This inspection and repair program will involve inserting cable cameras into live gas mains to investigate and locate points where brittle crack failures may occur in HDPE pipe. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

2.2 Consistency of project with stakeholder expectations

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to maintain our high levels safety and reliability. Consistent with the above insight, employing additional resources to manage the risks posed by HDPE will enable AGN to continue to provide a safe and reliable supply of natural gas to customers.

3 Risk Assessment

[redacted] It has therefore been assigned a Priority 2 rating.

4 Key Drivers and Assumptions

[redacted]

[redacted]

This project is also consistent with AGN's operational theme of "Maintain" network safety. It specifically relates to the following insights:

- Customers value AGN's high reliability and want it to keep providing the same (as a minimum) service levels.
- Customers view gas as a reliable source of energy.

5 Options

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	

[redacted]

6 *Forecast Cost for the Upcoming AAP*

[redacted]

Capital expenditure ($'000s real $2014/15)

Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Camera Crew	400	400	400	400	400	**2,000**
Repair Crew	1,080	1,080	1,080	1,080	1,080	**5,400**
Materials	836	836	836	836	836	**4,180**
Total	**2,316**	**2,316**	**2,316**	**2,316**	**2,316**	**11,580**

A more detailed cost breakdown can be found in Attachment A

7 *Consistency with National Gas Rules*

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the operating expenditure for this project is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services and to reduce the risk to human health and safety and property to as low as reasonably practicable and is of a nature that a prudent service provider would incur.

- *Efficient* – Carrying out investigations and repair work is more cost effective than replacing all the HDPE Class 575 pipes and can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – Minimising network risk and maintaining public safety are fundamental requirements for a gas network operator and reflects accepted and good industry practice. Reducing the risk to as low as reasonably practicable in a manner that balances cost and risk is also consistent with Australian Standard AS4645.
- *To achieve the lowest sustainable cost of delivering pipeline services* – Carrying out in-line camera inspections and repairs of points on the HDPE pipes where brittle crack failures may occur is a lower cost option than replacing all pipelines and is therefore consistent with the objective of achieving the lowest sustainable cost of delivering pipeline services.

Viewed in this way it is clear that the capital expenditure is consistent with rule 79(1)(a) of the National Gas Rules. It is also consistent with 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)), which includes maintaining the security of supply.

ATTACHMENT A – Detailed Cost Breakdown

This attachment provides further detail on the costs set out in section 6. All costs in this attachment are expressed in real $2014/15 values and exclude overheads.

Scope Metrics	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	
[redacted]	[redacted]
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Total annual cost **$2,316,000**

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

ATTACHMENT C – Risk Assessment

The top panel in the table below sets out the results of the untreated risk associated with HDPE pipes, while the bottom panel sets out the residual risks if the in-line inspections and repair work is carried out in conjunction with the targeted replacement of HDPE mains and the development of an integrity management program for HDPE pipes. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Catastrophic*	*Minor*	*Minor*	*Minor*	*Medium*	*Significant*	*Medium*	
	Risk Level	*High*	*Low*	*Low*	*Low*	*Moderate*	*High*	*Moderate*	*102*
		30	*08*	*08*	*08*	*14*	*20*	*14*	
Residual Risk	**Likelihood**	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
	Consequence	*Catastrophic*	*Minor*	*Minor*	*Minor*	*Medium*	*Significant*	*Medium*	
	Risk Level	*High*	*Low*	*Low*	*Low*	*Moderate*	*Moderate*	*Moderate*	*80*
		26	*05*	*05*	*05*	*12*	*15*	*12*	

Priority		**Priority Description**
Priority 1	(red)	Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2	(orange)	Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3	(yellow)	Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4	(green)	Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA53

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA53
Project Name	M36 Flagstaff Hill TP pipeline coating repair
Budget Category	Capex
Risk and Priority	High, Priority 2
Reference Docs	N/A
Confidentiality Claim	Yes (Attachment B)
PROJECT APPROVAL	
Prepared By:	Mujibur Rahman, *Corrosion Engineering*
Reviewed By:	Dominic Zappia, *Manager Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	The M36 Transmission Pressure (TP) pipeline runs from Seacombe Gardens to Flagstaff Hill and has a history of corrosion, with significant corrosion having been found at various points on the pipeline, some of which have required extensive repairs. The likelihood of further undetected corrosion on this pipeline is present and if left unchecked, could result in major gas escapes, which would require emergency repairs and/or replacement and could also result in the supply of gas to customers being interrupted. To deal with this risk, AGN intends to undertake an additional DCVG survey and to carry out any remediation works that may be necessary in the next Access Arrangement Period (AAP) to maintain the safety of network service provision. The untreated risks associated with corrosion on this pipeline have been rated as High (Priority 2).
Options Considered	Two options were considered as part of this business case: • Option 1 – Do not conduct a DCVG survey and just address any effects of corrosion as they arise through a reactive repair and replacement program. • Option 2 – Conduct a DCVG survey and, where necessary, carry out remediation works (planned identification and remediation program).
Option Selected	Option 2 was selected because it reduces the risks associated with the corrosion in a more cost effective manner than Option 1 (ie, because it avoids the additional costs of emergency repairs and replacements and the costs of turning gas off and on if sections of the pipeline need to be isolated to manage a gas escape).
Estimated Cost	The forecast capital expenditure for the replacement program in the next AAP is $0.693 million (real $2014/15).
Consistency with the NGR	The DCVG survey and repair work on the M36 pipeline complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • it is necessary to maintain and improve the safety of services and maintain the integrity of services (rule 79(1)(b) and rules 79(2)(c)(i) and (ii)); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (rule 79(1)(a)).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue to provide a safe and reliable supply of natural gas to our customers. More information on our stakeholder engagement program and results is provided in Chapter 3 of the Access Arrangement Information (AAI).

2 Background

The Seacombe Gardens to Flagstaff Hill (M36) transmission pipeline (TP) is a lateral off the Refinery Main, which was commissioned in 1967 to supply gas to the southern part of the Adelaide distribution network (a map of this pipeline is provided in Attachment A). This pipeline is the primary feeder to over 29,000 consumers in the southern suburbs of the Adelaide metropolitan area and consists of:

- a 2.2 km DN200 section - the DN200 steel pipe has a single-layer polyethylene tape wrap coating, which does not provide a high level of corrosion protection for underground steel pipe. The coating on DN200 section has deteriorated and dis-bonded in some locations. A section of this pipeline was abandoned in 2012 due the severity of the corrosion and was re-laid along an alternative alignment; and
- a 3.5 km DN300 section - the DN300 steel pipe has a coal tar enamel coating. Over the last 47 years, the condition of the coating has deteriorated, resulting in micro-crack defects and dis-bonding of the coating.

Steel pipes, like the M36 TP, are susceptible to corrosion, with such corrosion most likely to occur at locations where there are either coating defects, or where the coating has dis-bonded. DCVG surveys can be used to detect locations of coating defects and associated corrosion, but where coating dis-bonding has occurred, significant corrosion can be active before a coating defect is significant enough to be picked up by DCVG survey.

Over 20 excavations have been carried out over the last five years on the M36 pipeline in response to DCVG readings. Significant corrosion was found at 10 locations, some of which required extensive repair. Typical corrosion defects found on the pipeline are shown in the photos below.

Corrosion defects of M36 pipeline, repaired after integrity assessment, using type ‘B’ steel sleeve (a) and composite (b & c)

Available evidence suggests that the condition of the DN300 section is marginally worse than that the DN200 section, but given its close proximity to residential homes, the risk level pertaining to the DN200 section is considered higher.

Corrosion associated with coating would normally be detected using an inline inspection tool (intelligent pig) however, the transmission lines within the Adelaide metropolitan network were not constructed to be pigged, with numerous plug valves and tight bends preventing the passage of an intelligent pig. With the relatively short lengths and various physical constraints, inline inspection is not a viable integrity management tool.

The next DCVG survey on the M36 pipeline is due to occur in FY18/19, however, based on the level of corrosion identified from previous surveys it is considered prudent to conduct an additional DCVG survey in FY16/17.

The last three (2010, 2011 and 2012) DCVG surveys on pipelines of similar vintage and coating types detected 20-25 defects requiring further investigations. Based on these results it is estimated that the DCVG survey proposed on the M36 pipeline in FY16/17 will find 25 defects and the survey planned in FY18/19 an additional 25 defects requiring coating and pipeline remediation. In total it is estimated that 50 sites will require remediation over the next AAP (4.4 defects per km per survey).

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to maintain our high levels safety and reliability. Consistent with the above insight, the remediation of corrosion on TPs will enable AGN to continue to provide a safe and reliable supply of natural gas to customers.

3 Risk Assessment

The key risk addressed by this project is for the corrosion on the M36 pipeline to result in a major gas escape that then poses a risk to public safety and reliability of supply. It is unlikely that a catastrophic failure would occur, however, a pipe failure could result in significant gas release and major disruption of supply to consumers. An emergency repair would require isolation of a pipeline section and depending on the location and time of year, could affect several thousand consumers. The precise number of customers affected will depend on the location of the gas leak, the time of the year and the need for pressure reduction.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria.

In short, the untreated risk associated with the corrosion on the M36 pipeline has been assessed as "High" given the risk associated with a major gas escape contributing to a potential fire or explosion and has been assigned Priority 2. Further detail on the risk assessment that has been carried out can be found in Attachment C.

4 Key Drivers and Assumptions

The key drivers and assumptions for this project are set out below:

- Significant corrosion has been found on the M36 pipeline at a number of DCVG defect sites and the likelihood of further undetected corrosion is present.
- Undetected corrosion could lead to major pipe failure.
- Additional DCVG surveys are required to identify potential corrosion sites.
- Regular survey and maintenance will extend the pipeline life.
- For planning purposes it has been assumed that repairs will be spread evenly over the five years, i.e. an additional 10 excavations per year over the next AAP, with coating and pipe repairs carried out where necessary.
- The project is consistent with AGN's operational theme of "Maintain" network safety. It specifically relates to the following insights:
  - Customers value AGN's high reliability and want AGN to keep providing the same (as a minimum) service levels.

– Customers view gas as a reliable source of energy.

5 *Options*

Two options have been identified to deal with the risks posed by the corrosion on the M36 pipeline:

- Option 1 – Do not conduct a DCVG survey and just deal with any effects of corrosion as they arise through a reactive repair and replacement program
- Option 2 – Conduct a DCVG survey and, where necessary, carry out remediation works (planned identification and remediation program).

Note that because the M36 pipeline cannot be pigged, there is no alternative to the detection of corrosion defects by DCVG survey.

The costs and benefits associated with options 1 and 2 are summarised in the table below.

Costs and benefits of the options

Item	**Option 1** **Reactive repair and replacement program**	**Option 2** **Planned identification and remediation program**
Costs/Risks	If a planned remediation program is not carried out, then there is a risk that corrosion will result in a significant gas leak, which, in turn, results in: • human health and safety being put at risk and AGN being exposed to compensation claims – this risk is rated as high, • operational and compliance risks – these risks are rated as moderate; • more expensive emergency repair costs, which are estimated to cost approximately $30,000 per repair (this is approximately 2 times higher than the cost of planned works); and • supply being interrupted to several thousand customers, which would give rise to additional costs to manage the gas outage (ie, turn off and turn on). The costs for safe turn off and turn on range from $50 to $100 per customer, so if on average 1,000 customers were affected then it would cost $50,000-$100,000 to manage each gas outage. The costs associated with emergency repairs and managing gas outages are such that even if only 6-10 of the sites (out of the 50 that are expected to require remediation) result in a leak then the costs will exceed those under Option 2.	$0.693 million (real $2014/15) (see section 6 and Attachment A for a breakdown of costs)
Benefits	No upfront costs.	Carrying out the survey and remediation work will: • reduce the risk to human health and safety from high to moderate and operation and compliance risk from moderate to low (see Attachment B); • avoid the need for more expensive emergency repair costs in the event of a gas escape; • avoid the cost of managing a gas outage if a leak

Item	Option 1 Reactive repair and replacement program	Option 2 Planned identification and remediation program
		occurs; and • extend the life of the pipeline.

As this table highlights, Option 2 reduces the risks associated with the corrosion in a more cost effective manner than Option 1, because it avoids the additional costs of emergency repairs and replacements and the costs of turning gas off and on if sections of the pipeline need to be isolated to manage a gas escape. Option 2 has therefore been chosen and is considered consistent with the action that a prudent operator would take.

6 Forecast Cost for the Upcoming AAP

The table below sets out the forecast cost of carrying out the DCVG survey and excavation and repair works over the upcoming AAP. A more detailed cost breakdown can be found in Attachment A.

Forecast Capital Expenditure ($'000s Real 2014/15 – excluding overheads))

Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
DCVG survey	6.3					**6**
Excavation and repair	137.3	137.3	137.3	137.3	137.3	**687**
Total	**143.6**	**137.3**	**137.3**	**137.3**	**137.3**	**693**

The forecast expenditure has been estimated on the basis of the following assumptions:

- An additional DCVG survey is carried out in 2016/17.
- The excavation and repair work has been spread evenly across the AAP to ensure it can be effectively managed, with 10 additional pipeline excavations and remediations assumed to be carried out each year.
- The contractor and material costs are based on the actual costs that were incurred in 2014/15 carrying out a single exploratory TP pipeline excavation and repair, while the internal costs are based on APA's internal unit rates.

7 Consistency with National Gas Rules

Consistent with the requirements of rule 79(1)(a)1 of the National Gas Rules, AGN considers that the expenditure being sought for this project is:

- *Prudent* – The expenditure is necessary in order to ensure that the ongoing integrity of the M36 pipeline is maintained and to ensure that there are no major gas escapes that could impact public safety and reliability of supply. It is therefore of a nature that a prudent service provider would incur.
- *Efficient* – The proposed DCVG survey and remediation work is the only practical and effective option for dealing with the risk posed by corrosion on the M36 pipeline. Engineering assessments and design will be carried out by internal staff and field work will be carried out by external contractors based on competitively tendered rates. The expenditure is therefore of a nature that a prudent service provider acting efficiently would incur.

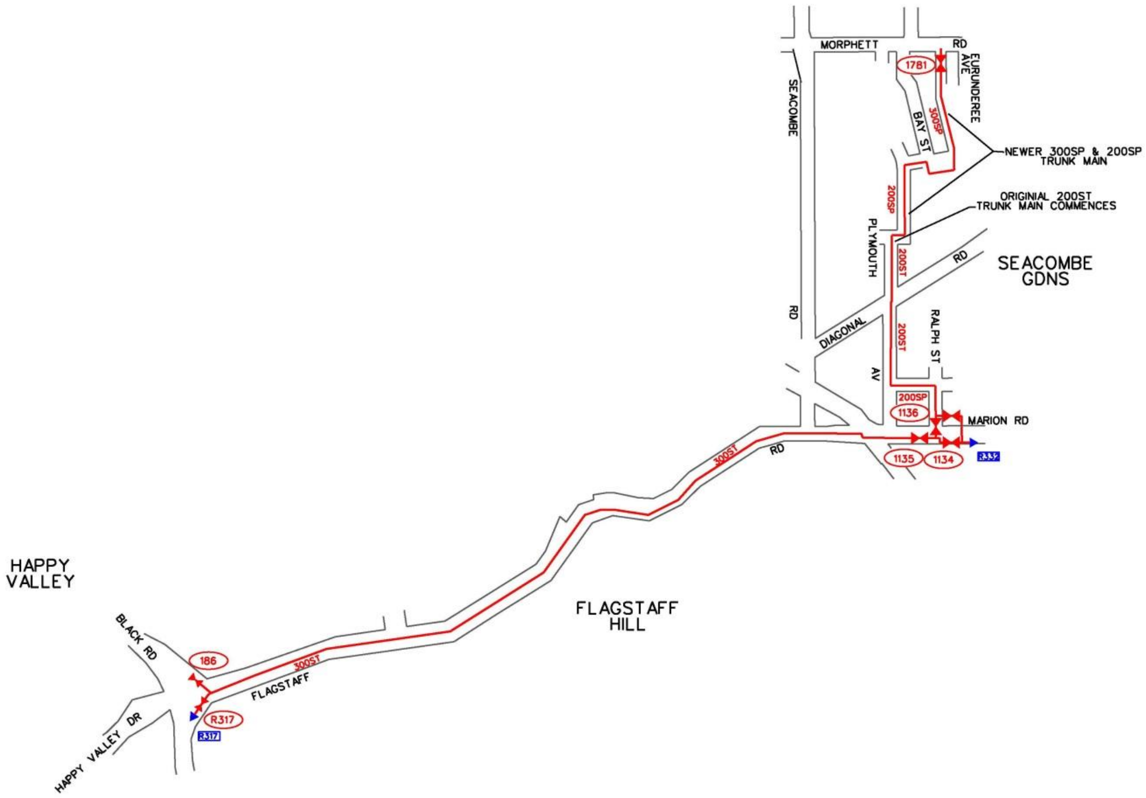
- *Consistent with accepted and good industry practice* – The ongoing effective management of the integrity of the M36 TP pipeline is consistent with Australian Standard AS2885.3 Pipelines - Gas and Liquid Petroleum, Part 3: Pipeline Integrity Management. Reducing the risks posed by the corrosion of this pipeline to as low as reasonably practicable and in a manner that balances costs and risks is also consistent with this standard.

- *To achieve the lowest sustainable cost of delivering pipeline services* – The DCVG survey and remediation work is necessary to maintain the long term integrity of the M36 pipeline. Failure to do so would result in additional expenditure (reactive response to a major gas escape and bringing forward replacement) and shorten the life of this pipeline. The project is therefore consistent with the objective of achieving the lowest sustainable cost of delivering services.

It follows from these points that the capital expenditure is consistent with rule 79(1)(a) of the National Gas Rules. The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- maintain and improve the safety of services (79(2)(c)(i)); and
- maintain the integrity of services (79(2)(c)(ii)).

ATTACHMENT A – M36 Flagstaff Hill TP Pipeline Map



ATTACHMENT B – Detailed Cost Breakdown

A detailed breakdown of the forecast cost estimate set out in section 6 is provided below.

Cost estimate is based on the following:

DCVG

[redacted]

- [redacted]

Excavation & Repair

[redacted]

- Proposed number of exploratory excavations and repairs per year: 10
- Cost per year for excavation & repair (10 x $13,726) = **$137,260**

ATTACHMENT C – Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the inspection and remediation works on the M36 Flagstaff Hill TP are not carried out (untreated risk), while the bottom panel sets out the residual risks if the works are carried out (residual risk). Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance	Financial Impact	Total Score of Risk Levels
Risk Untreated	Likelihood	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Major*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*High*	*Low*	*Moderate*	*Low*	*Low*	*Moderate*	*Low*	*85*
		25	*08*	*14*	*08*	*08*	*14*	*08*	
Residual Risk	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Major*	*Minor*	*Medium*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Negligible*	*Low*	*Negligible*	*Negligible*	*Low*	*Negligible*	*38*
		16	*03*	*06*	*03*	*03*	*06*	*01*	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA54

PROJECT REFERENCE	
Network	AGN – SA
Project No.	SA54
Project Name	Risk Management of HPDE – HDPE integrity management program
Budget Category	SIB Opex
Risk and Priority	High, Priority 2
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes
PROJECT APPROVAL	
Prepared By:	Chris Liew, *Integrity Manager*
Reviewed By:	Dominic Zappia, *Manager Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	[redacted] AGN intends to implement the following short to longer term measures: 1. Carry out a targeted replacement of HDPE mains (see 2015 SA Mains Replacement Plan); 2. Carry out in-line HDPE camera inspections (see business case SA52); 3. Install HDPE ground vents (see business case SA56); and 4. Develop a comprehensive integrity management plan for HDPE pipes, which includes developing an evidence based integrity management strategy aimed at optimising maintenance and replacement programs associated with HDPE mains. The latter of these actions is the subject of this business case.
Options Considered	[redacted]
Estimated Cost	The forecast operating expenditure for the HDPE integrity management program is $3.197 million (real $2014/15).
Non-Base Year	A step change of $3.197 million is required because the proposed expenditure does not currently form part of the base year opex and it is not reflected in the rate of change. The required step

Costs	change is being driven by an increase in the level of risk borne by AGN compared to what was borne in the base year and is also consistent with: • the longer term interests of consumers with respect to quality, safety and reliability of supply; and • rule 91 of the NGR (see below).
Consistency with the NGR	The proposed expenditure on this program is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services and therefore complies with rule 91(1).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue to provide a safe and reliable supply of natural gas to our customers. See Chapter 3 of the Access Arrangement Information for further detail.

2 Background

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2.1 Project scope

[redacted] The additional knowledge and understanding of risk and material failure behaviour and predicted performance will be an input into the longer term integrity management of HDPE, including optimising maintenance and future replacement strategies.

To this end, ongoing HDPE integrity management will involve a higher level of analysis to ensure risks are understood and effectively managed. This will, in turn, require:

- Failure root cause analysis.
- Material laboratory testing.
- Leak survey and in service camera inspection optimisation.
- Risk modelling.
- Reliability model development.
- Development of repair procedures.
- Development of replacement strategies.
- Monitoring of industry developments, advisory bulletins and recommendations related to integrity management of HDPE (locally and overseas).

The output of this analysis will be critical to formulating a long term Class 575 HDPE replacement strategy. In addition, the intellectual knowledge associated with the behaviour of polyethylene pipe will provide a base for the integrity management of the new generation medium density polyethylene (MDPE) and high density polyethylene (PE100) that, to date, have not shown a propensity for brittle crack failure.

The current integrity management resource pool for the South Australian Network business consists of an Integrity Manager and four FTE engineering resources. These resources are predominately focused on the integrity management of steel transmission pressure pipelines. A number of significant issues associated with coating defects and corrosion beneath dis-bonded coatings have been identified in this current regulatory period with a significant program of work proposed to identify and remediate corroded steel mains over the next regulatory period (see business cases SA10, SA21, SA21a, SA36, SA53, SA67).

The existing resource pool will be fully utilised optimising this program of work, in addition to a range of other routine integrity and engineering activities. Consequently there is no spare capacity to undertake significant additional workload on this new activity. Currently, resources are being diverted from other activities on an ad-hoc basis, to work on HDPE integrity management, but this situation is not sustainable going forward. It is therefore planned that another three FTE engineering resources be employed and that further pipe sampling and testing be carried out to manage the integrity issues associated with HDPE.

These additional resources will be used to optimise various risk management initiatives as well as developing an evidence based integrity management strategy aimed at optimising maintenance and replacement programs associated with HDPE mains. The resources will also be used to develop a robust reliability forecast model, which will enable the residual life of HDPE (approximately $300 million replacement value) to be optimised, maintenance costs to be minimised and the risk of premature asset replacement reduced.

2.2 Consistency of project with stakeholder expectations

As outlined in Chapter 3 of the Access Arrangement Information, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to maintain our high levels safety and reliability. Consistent with the above insight, employing additional resources to manage the risks posed by HDPE will enable AGN to continue to provide a safe and reliable supply of natural gas to customers.

3 Risk Assessment

[redacted]

[redacted]

[redacted] It has therefore been assigned a Priority 2 rating.

4 Key Drivers and Assumptions

The key assumptions and drivers for this project are outlined below:

[redacted]

- A more comprehensive failure analysis, research and testing program is required to optimise maintenance and replacement strategies.
- The current resource pool is insufficient to manage the additional work associated with managing HDPE risks.

This project is also consistent with AGN's operational theme of "Maintain" network safety. It specifically relates to the following insights:

- Customers value AGN's high reliability and want AGN to keep providing the same (as a minimum) service levels.
- Customers view gas as a reliable source of energy.

5 Options

Two options have been identified to deal with the risks outlined above:

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6 *Forecast Cost for the Upcoming AAP*

The table below sets out the operating expenditure that is forecast to be incurred in the next AAP if three additional FTEs are employed to develop a comprehensive integrity management program for HDPE pipes and additional pipe sampling and testing is carried out. A more detailed cost breakdown can be found in Attachment A along with an explanation of how the forecast has been derived.

Operating expenditure ($'000s real $2014/15)

Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Direct Labour	504*	489	489	489	489	**2,460**
HDPE Testing	58.3	58.3	53.3	48.3	43.3	**261.5**
R&D, External Consultants	95	95	95	95	95	**475**
Total	**657.3**	**642.3**	**637.3**	**632.3**	**627.3**	**3,197**

* Includes recruitment and training costs, which is only applicable in the first year.

6.1 Justification for non-base year opex – step change

Employing the resources outlined above will give rise to a $3.197 million increase in operating expenditure over the AAP (or $0.64-$0.66 million per annum). This expenditure does not currently form part of the base year opex, nor is it reflected in the rate of change that AGN has used when applying the base step trend approach. A step change of $3.197 million is therefore required to give effect to the decision to develop a comprehensive integrity management program for HDPE pipes.

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The expenditure also satisfies rule 91(1) of the National Gas Rules (see section below) and should therefore form part of AGN's opex forecast.

7 Consistency with National Gas Rules

Consistent with the requirements of Rule 91 of the National Gas Rules, AGN considers that the proposed operating expenditure is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services and to reduce public risk and is of a nature that a prudent service provider would incur.
- *Efficient* – Employing additional technical resources to develop an integrity management plan for HDPE, in conjunction with the targeted replacement of HDPE pipes and in-line camera inspections, is the most cost effective way to reduce the risks posed by these pipes to as low as reasonably practicable. The only other options that could be implemented would be to use external resources to manage the integrity of these pipes, or to replace all the HDPE pipes, but these are more expensive options. The proposed expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- *Consistent with accepted and good industry practice* – Maintaining adequate level of knowledge on the existing network condition and high standard risk management practices are fundamental requirements for gas network operators and reflects accepted and good industry practice. This is consistent with Australian Standard AS 4645 and required to reduce risks to as low as reasonably practicable.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The additional knowledge and understanding of risk and material failure behaviour will enable optimisation of the maintenance and replacement of HDPE mains, which will contribute to the achievement of the lowest sustainable cost of service delivery over the medium to longer term.

Attachment A – Detailed Cost Breakdown

This attachment provides further detail on the costs set out in section 6. All costs in this attachment are expressed in real $2014/15 values.

Direct labour costs

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Attachment B – Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the integrity management program for HDPE pipes is not developed, while the bottom panel sets out the residual risks if the program is developed. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Catastrophic*	*Minor*	*Minor*	*Minor*	*Medium*	*Significant*	*Medium*	
	Risk Level	*High*	*Low*	*Low*	*Low*	*Moderate*	*High*	*Moderate*	*Priority 2 102*
		30	*08*	*08*	*08*	*14*	*20*	*14*	
Residual Risk	**Likelihood**	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
	Consequence	*Catastrophic*	*Minor*	*Minor*	*Minor*	*Medium*	*Significant*	*Medium*	
	Risk Level	*High*	*Low*	*Low*	*Low*	*Moderate*	*Moderate*	*Moderate*	*Priority 2 80*
		26	*05*	*05*	*05*	*12*	*15*	*12*	

Priority		**Priority Description**
Priority 1	(red)	Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2	(orange)	Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3	(yellow)	Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4	(green)	Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

APA Group

BUSINESS CASE - SA56

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA56
Project Name	Gas vents
Budget Category	Opex and Capex
Priority	2
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes
PROJECT APPROVAL	
Prepared By:	Chris Liew, *Integrity Manager*
Reviewed By:	Dominic Zappia, *Manager, Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

[redacted]	
Rationale for Project	This project consists of installing gas vents [redacted]
Options Considered	[redacted]
Option Selected	[redacted]
Estimated Cost	[redacted]
Justification for Non-Base Year Cost	[redacted]
Consistency	[redacted]

with the NGR	[redacted]
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Improve* theme because its implementation will enable AGN to improve community safety across the network. Chapter 3 of the AAI provides more information on the stakeholder engagement program conducted by AGN.

2 Background

[redacted]

[redacted]	[redacted]		[redacted]		[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]

1. [redacted]

[redacted]

[redacted]

[redacted]

2.1 Project Scope

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]				
[redacted]	[redacted]				

[redacted]

[redacted]

[redacted]

3 Risk Assessment

[redacted]

[redacted]

[redacted]

4 KEY DRIVERS & ASSUMPTIONS

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

5 Options

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

6 Forecast Cost for the Upcoming Regulatory Period

The costs for Option 2 consist of:

- Purchase and fit out of a vacuum excavation truck in the first half of financial year 2016/17;
- Utilising a 2 person crew with capacity to complete 20 sites per day (4,600 sites) per year; and
- Additional APA internal resource costs.

A summary of cost (both opex and capex) by financial year is provided in the table below. A detailed cost breakdown has been included in Attachment A.

$000's (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Sites (volumes)	2,300	4,600	1,000			**7,900**
Opex (Labour & materials)	267	534	116			**917**
Capex (Vacuum Truck)	200					**200**
Total Cost	**467**	**534**	**116**	**0**	**0**	**1,117**

7 Justification of Non-Base Year Cost

[redacted]

- [redacted]
- [redacted]

8 Consistency with the National Gas Rules

Consistent with the requirements of Rule 91 of the National Gas Rules, AGN considers the expenditure detailed in this project is:

- *Prudent* – the expenditure is necessary in order to maintain the integrity of services and to reduce the risk of incidents associated with undetected leaks;
- *Efficient* – AGN considers that using the proposed gas vents is a practical and effective tool to improve risk management associated with the high risk impervious areas;
- *Consistent with accepted and good industry practice* – Maintaining effective leak detection is a fundamental requirement for safe network operation and is consistent with network owner's/operator's obligation to reduce risks to as low as reasonably practicable; and
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – Taking measures to avoid potential catastrophic incidents contributes to the long term sustainability of pipeline services.

ATTACHMENT A – Detailed Cost Breakdown

Item	Cost $
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
Total	1,116,400

[redacted]

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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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ATTACHMENT C – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Major*	*Minor*	*Minor*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*High*	*Low*	*Low*	*Low*	*Moderate*	*Moderate*	*Moderate*	***91***
		25	*08*	*08*	*08*	*14*	*14*	*14*	
Residual Risk	**Likelihood**	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	
	Consequence	*Major*	*Minor*	*Minor*	*Minor*	*Medium*	*Medium*	*Medium*	
	Risk Level	*High*	*Low*	*Low*	*Low*	*Moderate*	*Moderate*	*Moderate*	***72***
		21	*05*	*05*	*05*	*12*	*12*	*12*	

Priority		Priority Description
Priority 1	(red)	Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2	(orange)	Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3	(yellow)	Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4	(green)	Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE – SA57

PROJECT REFERENCE	
Network	AGN– SA
Project No.	SA57
Project Name	Applications Upgrade Project
Budget Category	SIB Capex
Risk and Priority	High, Priority 2
Reference Docs	2015 South Australia Network IT Investment Plan
Confidentiality Claim	Yes (Attachment A)
PROJECT APPROVAL	
Prepared By:	Trevor Coles, *Applications Manager Information Technology*
Reviewed By:	Heather Reynolds, *Vendor Manager Information Technology*
Approved By:	Bill Fazl, *General Manager Information Technology*

1 Project Overview

Rationale for Project	The Applications Upgrade Project is required to ensure that AGN can: • continue to maintain reliable, compliant and efficient business processes and systems; • preserve the on-going integrity of these services; and • comply with Retail Market Procedures and other relevant regulations and legislation. If the project is not carried out, there is a risk that: • the safety and integrity of network services will be compromised as critical business IT applications become increasingly unstable and vulnerable to security breaches, and as the rate of failure in older critical business IT applications increases; • AGN will be unable to comply with Retail Market Procedures if there is a system failure; and • a range of other efficiencies will not be achieved.
Options Considered	Three options were considered to address the risks outlined above: • Option 1: Do nothing, which would leave AGN exposed to a high level of operational risk. • Option 2: Upgrade critical IT applications every two years, which would reduce the level of operational risk to moderate. • Option 3: Delay the upgrade of some applications, which would result in a small reduction in risk but the overall level of operational risk would remain high.
Option Selected	Option 2 has been selected because it is the most cost effective long term option and provides significantly better risk reduction at a lower cost than the other two options.
Estimated Cost	The forecast capital expenditure for the Applications Upgrade project is $17.7 million (real $2014/15) over the next AAP.
Consistency with the NGR	The Applications Upgrade project complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because it is: • necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations (rules 79(2)(i), (ii) and (iii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue to effectively and efficiently maintain its current business operations and service levels. Chapter 3 of the AAI provides more

	information on the stakeholder engagement.

2 Background

The Australian Gas Networks (AGN) application systems environment consists of a number of disparate application systems that are tightly integrated. With tightly integrated systems there is a resulting interdependency between applications and their associated technologies. Upgrades to applications, and their associated technologies, are typically not completed in isolation, this to ensure greater consistency and interoperability. To minimise risk, upgrade projects are performed as internal Business & Technology (B&T) projects.

To ensure that its business processes and IT application systems are efficient and effective, AGN has undertaken significant investment in a number of B&T projects over the past few years. This investment is continuing, with separate business cases outlining specific projects for the next Access Arrangement period (AAP).

In the current AAP (pre FY17) a number of major projects to nationalise and upgrade key application systems were implemented. These projects provided improved scalability, flexibility and reliability, while also ensuring that AGN continues to meet its obligations under the SA Retail Market Procedures. The B&T projects delivered over the current AAP include:

- Billing Optimisation – Nationalising the Metering & Billing System (Oracle CC&B).
- National Works Management – Enterprise Asset Management (Maximo).
- Telemetry System – Nationalising the Telemetry System (Clear SCADA).
- Historian Reporting – Nationalising the Historian Reporting System (OSi/Pi).
- Billing Estimation Model – Nationalising the Billing Estimation Model (Accruals).

These projects delivered sustainable application systems and aligned business processes to ensure that AGN's systems can continue to meet current and future needs. AGN proposes to continue its prudent investment in B&T projects in the next AAP to maintain the integrity of services and to mitigate risks. As part of this investment, AGN intends to carry out an upgrade of critical information technology (IT) applications to ensure that these systems are kept up-to-date.

2.1 Project scope

The upgrade will involve systematically upgrading the software and applications outlined in the Applications Upgrade Plan (see table on page 4) to ensure that AGN can continue to maintain reliable, compliant and efficient business processes and systems and preserve the on-going integrity of the services. These upgrades are required to both manage the transition of one version of the technology to a subsequent improved version of the technology and correct defects in the technology (which includes how a technology type interacts with other technology types). Upgrade versions are provided by vendors who recommend that their technology be upgraded to ensure ongoing support and maintenance contracts.

The primary benefit of this project is that it will substantially reduce the level of risk of system(s) failing or the integration between systems not operating as intended, which is of considerable importance given that:

- critical IT applications are linked together and are reliant on each other to allow high volumes of transactions to flow from one to the other;
- the full functionality of these linked critical IT application systems is necessary to satisfy the Retail Market Procedures and AGN's business requirements;
- significant IT investment has been made in recent years to ensure that AGN's application systems meet their obligations as set out in the Retail Market Procedures and AGN needs to ensure this investment is managed and maintained and this requires an upgrade strategy; and
- failure of the critical systems will have adverse effects across the business as the true state of the network will not be reliably known creating safety and operational risks.

Some other benefits of upgrade critical IT applications are that it:

- ensures upgraded applications continue to provide required integrated functionality to support business processes;
- manages alignment with other co-existing applications;
- ensures validity of support requirements with technology vendors;
- introduces appropriate new functionality;
- improves software performance and efficiency and stability of IT systems over time;
- provides for the continuation of IT vendor support (this requires movement to a recent version of the software);
- improves the security and integrity of business information as vendors place greater emphasis on these solutions ; and
- provides for compliance with the latest IT systems with market requirements.

Generally an application upgrade will involve not only the application upgrade itself, but also upgrades to the underlying associated technology platform components, assessment, design and implementation of any changes to configuration, customisations and integrations associated with the upgrades and complete testing of all impacted end to end processes.

Software application assets are usually upgraded on a 2 year cycle[1] depending on the assets and the policies of the vendors for the frequency of upgrades. There exist interdependencies between the various software applications, which are integrated to support business requirements. This interdependency creates a working construct of software applications, and associated technology platform components, that are at risk if they are not maintained at compatible software release levels as prescribed by technology vendors.

1 Mobility technology upgrades have been identified as an exception to the applied 2 year cycle of application upgrades. The rapid change in technology cycle and the ongoing speed of mobility based change indicates that a yearly upgrade cycle for Mobility is a prudent approach in this area.

To ensure that the IT application systems are kept stable and at optimum performance, AGN utilises an application lifecycle management methodology to determine upgrade timelines and priorities, which is outlined in Attachment B. The application upgrade plan outlined above is in place as a stay in business program of work that ensures compliance with an underlying principle of staying at a minimum of (N-1) for application upgrades. This enables appropriate levels of operation and inter-operability between various vendor provided technologies. This application roadmap is used to identify and prioritise upgrades, and has been used as the basis for the development of the Applications Upgrade Plan, which sets out the applications and the frequency of upgrades that AGN proposes to carry out in the next AAP (see table below).

Applications Upgrade Plan.

Upgrade Projects	FY17	FY18	FY19	FY20	FY21
Billing Estimation Model	X		X		X
Dial Before You Dig		X		X	
Metering & Billing System	X		X		X
Enterprise Asset Management	X		X		X
Geospatial Information System					X
Telemetry System		X		X	
Historian System		X		X	
FRC Market Gateway		X		X	
Business Intelligence Reporting – FRC	X		X		X
Middleware – BizTalk		X		X	
Field Data / Mobility	X	X	X	X	X

2.2 Consistency of project with stakeholder expectations

As outlined in Chapter 3 of the AA Information, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to prudently and efficiently maintain current reliability and service levels. Consistent with the above insight, the applications upgrade will enable AGN to continue to effectively and efficiently maintain its current business operations and service levels.

3 Risk Assessment

If AGN's critical business IT applications are not upgraded there is a risk that:

- these applications will become increasingly unstable and vulnerable to security breaches, which could put the safety of network services at risk;
- failure in older applications may occur, resulting in unplanned production outages;
- AGN will not comply with Retail Market Procedures if there is a failure of key IT systems;
- core applications will no longer be supported by IT vendors;
- the IT systems may be unable to support business strategic objectives, particularly with national alignment and the delivery of initiatives to improve cost effectiveness;

- strategic imperatives and architectural weaknesses identified in the IT Strategic Plan cannot be addressed;
- targets for effective IT development and minimisation of support costs may not be achieved;
- technology upgrades for core software will be required so not continuing with the planned upgrades will mean the opportunity for 'change out' of inefficient technologies will be missed; and
- as software licence renewals are becoming due, staying with existing systems will lock AGN into old technology and another licence cycle.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. Further detail on the risk assessment that has been carried out can be found in Attachment E.

In short, the untreated risk associated with the applications systems has been assessed as high from an operational perspective, and accorded a Priority 2 rating.

4 Options

Three options have been identified to deal with the operational risks posed by the application systems:

- Option 1 – Do nothing.
- Option 2 – Upgrade critical IT applications on a regular basis (ie, every two years).
- Option 3 – Delay the upgrade of metering and billing and enterprise asset management systems but upgrade other application on a regular basis.

The costs and benefits associated with these three options are summarised in the table below. Attachment E contains more information on the estimated risk under each option.

Costs and benefits of the options

Item	Option 1 Do Nothing	Option 2 Upgrade critical IT applications on a regular basis	Option 3 Delay the upgrade of some applications (or not upgrade some applications)
Costs/Risks	High operational risks, which will result in higher costs over the longer run if IT systems become unstable, fail or subject to security breaches. Not upgrading the applications will also mean that other efficiencies cannot be achieved.	$17.7 million (real $2014/15) (see Attachment A)	$13.15milion (real $2014/15) (see Attachment A) Operational risks reduced but still high given the potential for the delay to upgrades of metering and billing systems and enterprise asset management systems to result in. ▪ a reduction in availability of services; ▪ a reduction in integrity of services; and ▪ an inability to comply with regulatory obligations or requirements.
Benefits	No upfront costs.	Reduces the operational risk to moderate and allows other efficiencies to be achieved.	Reduces the operational risk relative to Option 1, but to a lesser extent than under Option 2.

The operational risk under option 1 is too high to be considered a feasible option. The only feasible options are therefore options 2 and 3. Given the difference in costs, benefits and risks under these two options, further analysis was carried out to calculate the cost of reducing the level of risk under the two options. This was calculated by dividing the cost of the option by the reduction in the risk score achieved under the relevant option. The risk scores are set out in Attachment E and have been calculated by taking the difference between:

- the risk score that has been calculated assuming the applications are not upgraded (untreated risk score: 91); and
- the residual risk scores that have been calculated assuming the actions identified under the options are carried out (Option 2 residual risk score: 73 and Option 3 residual risk score: 78).

The results of this analysis are summarised in the table below.

Risk adjusted analysis

	Cost $M	Risk Reduction Score	$'000 Per Risk Reduction Score
	(a)	(b)	(d)=(a)/(b)x1000
Option 2	$17.7	18	$983
Option 3	$13.15	13	$1,012

As the last column of this table reveals, Option 2 is the most cost effective option and provides significantly better risk reduction at a lower cost. Option 2 has therefore been selected.

5 *Forecast Cost for the Upcoming AAP*

The table below provides a summary of the capital expenditure that is forecast to be incurred in the next AAP under Option 2.

$k (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Billing Estimation Model	242		242		242	**727**
Dial Before You Dig		269		269		**539**
Metering & Billing System	1,559		1,559		1,559	**4,676**
Enterprise Asset Management	1,473		1,473		1,473	**4,420**
Geospatial Information System*					1,016	**1,016**
Telemetry System		767		767		**1,533**
Historian System		702		702		**1,404**
FRC Market Gateway		235		235		**470**
Business Intelligence Reporting – Retail Market	210		210		210	**630**
Middleware – BizTalk		312		312		**625**
Field Data / Mobility Systems	200	200	200	200	200	**1,002**
Licence Growth	111	115	122	130	138	**616**
Total	**3,795**	**2,601**	**3,807**	**2,616**	**4,839**	**17,658**

* The GIS only needs to be upgraded once over the AAP because a new GIS is proposed to be installed between 2016/17 and 2017/18.

The approach that AGN has used to develop this forecast and its proposed approach to carrying out the work is outlined below:

- AGN utilises an industry standard B&T Project Methodology, which is managed through formal governance. This B&T Methodology divides the projects into key stages – concept, develop, plan, deliver and close. Each stage consists of key tasks and activities to ensure the consistency and standardisation across projects. The project methodology is outlined in Attachment B.
- The methodology includes an Estimation Tool, to ensure project estimates are standard and consistent. This estimation tool has been used to forecast the work and cost estimates for the application upgrade program of work. This estimation tool utilises historic figures from the current AAP for resource work effort estimates. The work estimates are based on a complexity matrix tool, which uses a series of questions to categorise projects into simple, medium and complex.
- The material and direct labour costs, and applicable planning, design and commissioning charges, are based on historic actual costs of similar projects. Resource Unit Costs (both internal and external) are based on AGN's Project Management Office research, where actual placement costs have been used based on historical project resources and current resourcing rates (FY15).
- When implementing the project, AGN will use a formalised Project Methodology and utilise a combination of internal and external resources to deliver the program of work. The Project Methodology is outlined in Attachment B and provides a consistent, standard and quality assured project implementation framework. The Project Management Office (PMO) will provide

guidance and governance to the project, ensuring that the work is carried out in a professional manner.

In addition to upgrades to the existing suite of application systems, the forecast capital expenditure includes the cost of software licence growth, which is estimated to be approximately 5% per license unit (real average annual increase). This forecast is based on the following drivers and metrics:

- For customer connections, software and technical licensing is a one to one relationship. During the FY17 to FY21 AAP, AGN's customers and connections forecast is aligned with the AGN Demand Forecast.
- The number of internal users is the most common mechanism used by software application vendors for charging for licenses. For the FY17 to FY21 AAP internal user growth is expected to be 2.5% p.a..
- The remaining software is generally licensed by services or CPU usage. The growth requirements in this area for FY17 to FY21 AAP is expected to be 5% p.a..

A more detailed breakdown of the costs associated with the upgrade of each critical business IT system, based on the Project Estimation breakdown, is provided in Attachment A.

6 Consistency with National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the capital expenditure to implement the Applications Upgrade project is:

- *Prudent* – The expenditure is necessary to maintain the integrity of services and comply with regulatory obligations and requirements (see risk assessment section) and is of a nature that a prudent service provider would incur.
- *Efficient* – The proposed project is the most cost effective solution and will enable AGN to maintain its operational efficiency and address the high risks of non-compliance with relevant regulations and legislation, potential customer and business interruptions and corresponding adverse financial and reputation impacts. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The manner in which AGN intends to carry out the upgrade (ie, by using a combination of internal and external resources to deliver the program of work and using the Project Management Office (PMO) to provide guidance and governance to the project) can also be considered efficient.
- *Consistent with accepted and good industry practice* – The Applications Upgrade project will ensure that AGN continues to operate in line with good industry practice, in terms of having all critical systems up to date and supported by vendors.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The Applications Upgrade project is necessary to mitigate the risks associate with operating on older versions of the software with the resultant performance and cost implications should these systems fail and is therefore consistent with the objective of achieving the lowest sustainable cost of service delivery.

The proposed capital expenditure is also consistent with rule 79(1)(b), because it is necessary to:

- Maintain and improve the safety of services (79(2)(c)(i)) – The safety of services will be adversely affected if any of the critical IT systems fails or if there is a security breach.
- Maintain the integrity of services (79(2)(c)(ii) – The integrity of the services will be adversely affected if critical systems are unavailable.
- Comply with a regulatory obligation (79(2)(c)(iii)) – Regulatory obligations will be breached if key systems are not available (e.g. Retail Market Procedures requirements for processing timeframes).

Attachment A – Cost breakdown

The tables below set out the costs of upgrading applications. The costs in these tables are for a single upgrade only and are expressed in $2014/15 values.

Billing Estimation Model

IT & ICT Procurement Estimations Template: B&T Projects			
Project Name:	Billing Estimation Model		
Project Complexity:	Simple		
Project Type:	Upgrade		
Estimations Summary			
Total Project (end to end)	Effort (Days)	Total Cost	
End to End Total	210.4	$ 242,236.80	
Estimations by Project Stage			
		Stage Cost	
Develop Stage Total	48.2	$ 55,352.00	
Plan Stage Total	52.8	$ 57,059.20	
Deliver Stage Total	97.2	$ 115,013.76	
Close Stage Total	12.2	$ 14,811.84	

Dial Before You Dig

IT & ICT Procurement Estimations Template: B&T Projects			
Project Name:	Dial Before You Dig		
Project Complexity:	Medium		
Project Type:	Upgrade		
Estimations Summary			
Total Project (end to end)	Effort (Days)	Total Cost	
		Cost Incl. Cont.	
End to End Total	225	$269,319.52	
Estimations by Project Stage			
		Stage Cost	
Develop Stage Total	64	$ 99,962.72	
Plan Stage Total	64	$ 72,540.16	
Deliver Stage Total	86	$ 86,141.44	
Close Stage Total	10	$ 10,675.20	

Metering & Billing System

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Metering & Billing System	
Project Complexity:	Complex	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	1167	$ 1,558,636.00
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	290	$ 357,588.00
Plan Stage Total	396	$ 526,248.80
Deliver Stage Total	439	$ 618,895.20
Close Stage Total	42	$ 55,904.00

Enterprise Asset Management

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Enterprise Asset Management	
Project Complexity:	Complex	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	959	$ 1,473,299.20
Estimations by Project Stage		
Develop Stage	Effort (Days)	Estimate Assumptions
		Stage Cost
Develop Stage Total	208	$ 256,819.20
Plan Stage Total	354	$ 455,699.20
Deliver Stage Total	366	$ 726,387.20
Close Stage Total	31	$ 34,393.60

Geospatial Information System

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Geospatial Information System	
Project Complexity:	Complex	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	792	$ 1,016,352.28
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	180	$ 322,734.28
Plan Stage Total	237	$ 280,130.40
Deliver Stage Total	341	$ 377,295.60
Close Stage Total	34	$ 36,192.00

Telemetry System

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Telemetry System	
Project Complexity:	Medium	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	659	$ 766,716.00
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	165	$ 186,780.00
Plan Stage Total	164	$ 199,716.00
Deliver Stage Total	288	$ 335,500.00
Close Stage Total	42	$ 44,720.00

Historian System

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Historian System	
Project Complexity:	Medium	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	684	$ 702,220.00
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	190	$ 186,560.00
Plan Stage Total	210	$ 247,060.00
Deliver Stage Total	273	$ 256,520.00
Close Stage Total	11	$ 12,080.00

FRC Market Gateway

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	FRC Market Gateway	
Project Complexity:	Simple	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	280	$ 235,039.00
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	60	$ 61,270.00
Plan Stage Total	66	$ 70,114.00
Deliver Stage Total	143	$ 91,575.00
Close Stage Total	11	$ 12,080.00

Business Intelligence Reporting – FRC

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Business Intelligence Reporting - FRC	
Project Complexity:	Simple	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	268	$ 209,874.20
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	57	$ 57,838.00
Plan Stage Total	54	$ 57,794.00
Deliver Stage Total	146	$ 82,162.20
Close Stage Total	11	$ 12,080.00

Middleware – BizTalk

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Middleware - BizTalk	
Project Complexity:	Medium	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	240	$ 312,312.00
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	49	$ 84,568.00
Plan Stage Total	60	$ 68,728.00
Deliver Stage Total	120	$ 148,104.00
Close Stage Total	10	$ 10,912.00

Field Data / Mobility Systems

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Field Data / Mobility Systems	
Project Complexity:	Simple	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	173	$ 200,440.00
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	47	$ 38,456.00
Plan Stage Total	44	$ 52,536.00
Deliver Stage Total	75	$ 102,344.00
Close Stage Total	7	$ 7,104.00

[redacted]

[redacted]

Option 2 costs: Upgrade applications every two years

$k (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Billing Estimation Model	242		242		242	**727**
Dial Before You Dig		269		269		**539**
Metering & Billing System	1,559		1,559		1,559	**4,676**
Enterprise Asset Management	1,473		1,473		1,473	**4,420**
Geospatial Information System*					1,016	**1,016**
Telemetry System		767		767		**1,533**
Historian System		702		702		**1,404**
FRC Market Gateway		235		235		**470**
Business Intelligence Reporting – FRC	210		210		210	**630**
Middleware – BizTalk		312		312		**625**
Field Data / Mobility Systems	200	200	200	200	200	**1,002**
Licence Growth	111	115	122	130	138	**616**
Total	**3,795**	**2,601**	**3,807**	**2,616**	**4,839**	**17,658**

* The GIS only needs to be upgraded once over the AAP because a new GIS is proposed to be installed by 2018/19.

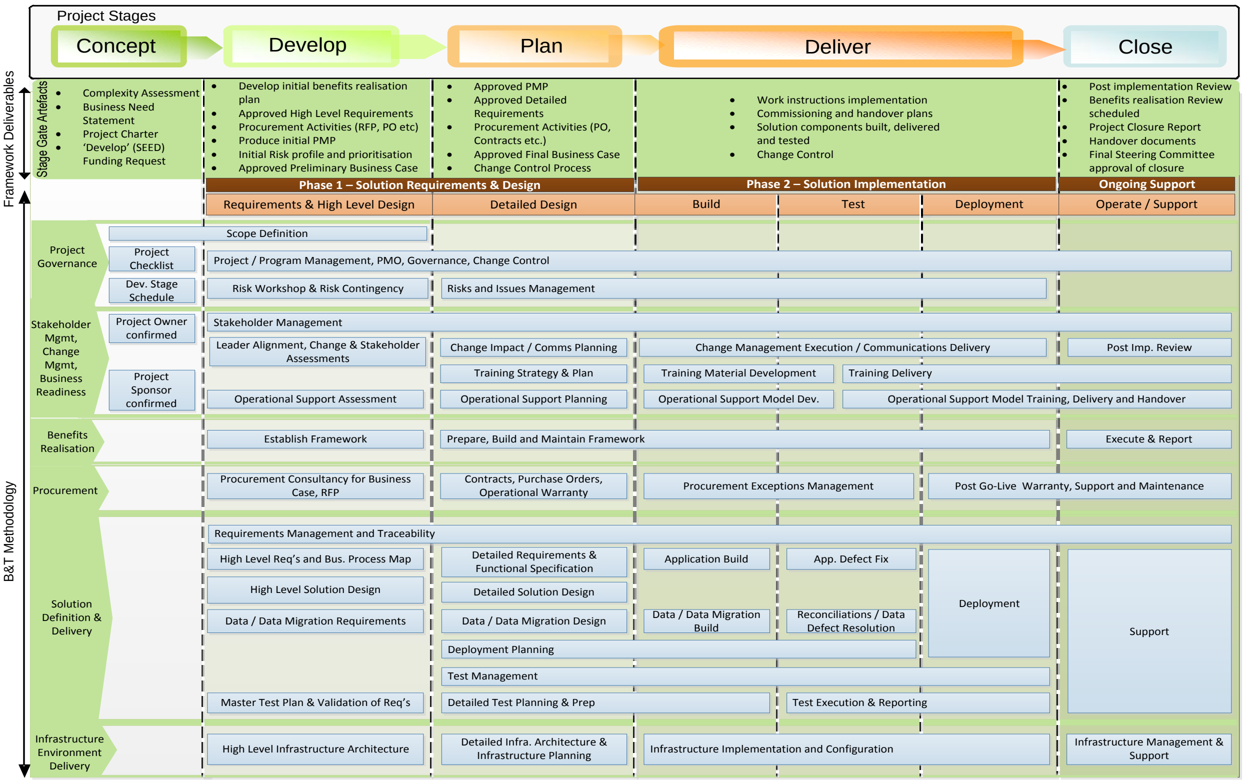
Option 3 costs: Delay the upgrade of metering and billing system and enterprise asset management applications

$k (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Billing Estimation Model	242		242		242	**726**
Dial Before You Dig		269		269		**538**
Metering & Billing System		1,559			1,559	**3,118**
Enterprise Asset Management			1,473			**1,473**
Geospatial Information System*					1,016	**1,016**
Telemetry System		767		767		**1,534**
Historian System		702		702		**1,404**
FRC Market Gateway		235		235		**470**
Business Intelligence Reporting – FRC	210		210		210	**630**
Middleware – BizTalk		312		312		**624**
Field Data / Mobility Systems	200	200	200	200	200	**1,000**
Licence Growth	111	115	122	130	138	**616**
Total	**763**	**4,159**	**2,247**	**2,615**	**3,365**	**13,149**

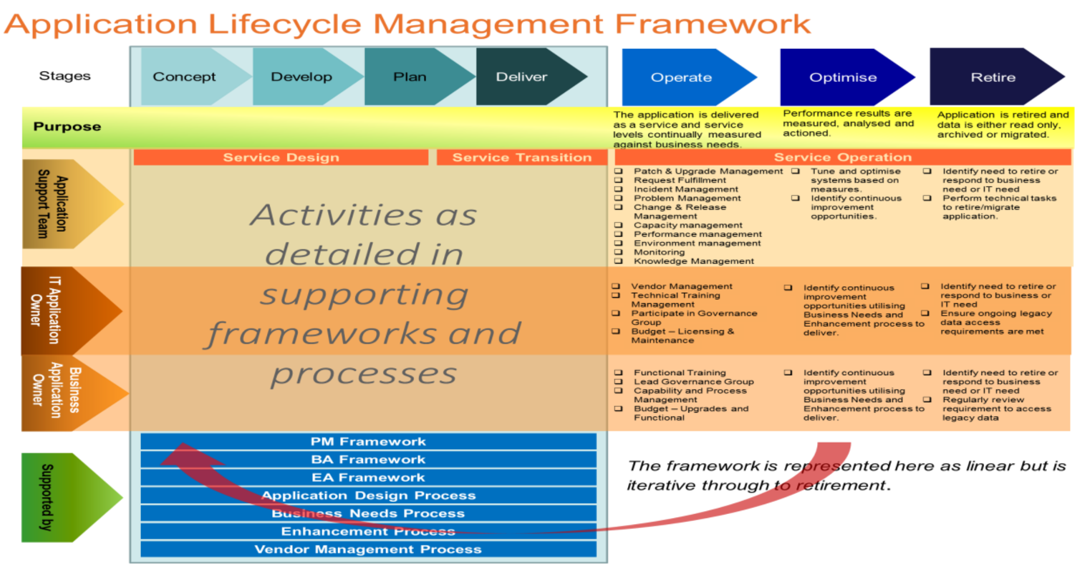
* The GIS only needs to be upgraded once over the AAP because a new GIS is proposed to be installed by 2018/19.

Attachment B – Methodologies

Project Methodology on a page



Application Lifecycle Methodology



Attachment D– Functionality Maintained by the Upgrades

Application Upgrades	Core Business Functions Maintained
Billing Forecasting and Estimation Model	• Delivery Point Forward Estimate • Interval Consumer Management • Base Load & TSF Calculation
Dial Before You Dig	• Management of National Dial Before You Dig Enquiries • Asset Location Notification
Metering & Billing System	• Market Transaction Workflow • Meter Reading • Delivery Point Billing
Enterprise Asset Management	• Planning • Dispatching Work • Job Completion Details • Delivery Point Status Management • Preventative Maintenance • Contractor Payment • Meter Management
Geospatial Information System	• Map Base (Cadastre) Management • Delivery Point Lifecycle Management • Network Configuration/Connectivity Management • Emergency Response Management • Mains Extension & Replacement Planning
Telemetry System	• Pressure Monitoring • Custody Transfer Monitoring & Reporting
Historian System	• National storage and operational use of time series telemetry data • Interval Meter Monitoring & Reporting • Billing information
FRC Market Gateway	• Send & Receive Service Order Requests • Send & Receive Meter Fix • Send & Receive Customer Transfer requests
Business Intelligence Reporting - FRC	• Reporting solution used for monitoring market message transactions, as well as some operational reporting • Complying with market rules
Middleware	• Electronic messaging between disparate systems • Monitoring of transaction data • Management of business rules • Preserve the integrity of the services
Field Data / Mobility Systems	• In-field capture of asset information • In- field capture of work completed • In-field follow-up job orders

Attachment E– Risk Assessment

The top panel in the two tables below sets out the results of the risk assessment assuming applications are not upgraded, while the bottom panel sets out the residual risks if the works outlined under Option 2 and Option 3 are implemented. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

Option 2: Upgrade all critical IT applications every two years

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels	Cost of Unit of Risk Reduction
Risk Untreated	Likelihood	*Possible*	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Unlikely*	*Priority 2*	
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Minor*	*Significant*		
	Risk Level	*Moderate*	*Negligible*	*High*	*Moderate*	*Moderate*	*Low*	*Moderate*	***91***	
		14	*02*	*24*	*14*	*14*	*08*	*15*		
Risk Treated	Likelihood	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Priority 3*	
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Minor*	*Significant*		
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Moderate*	*Low*	*Moderate*	***72***	
		12	*02*	*15*	*12*	*12*	*05*	*15*		

Option 3: Delay the upgrade of some applications

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels	Cost of Unit of Risk Reduction
Risk Untreated	Likelihood	*Possible*	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Unlikely*	*Priority 2*	
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Minor*	*Significant*		
	Risk Level	*Moderate*	*Negligible*	*High*	*Moderate*	*Moderate*	*Low*	*Moderate*	***81***	
		14	*02*	*24*	*14*	*14*	*08*	*15*		
Risk Treated	Likelihood	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Priority 2*	
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Minor*	*Significant*		
	Risk Level	*Moderate*	*Negligible*	*High*	*Moderate*	*Moderate*	*Low*	*Moderate*	***78***	
		12	*02*	*20*	*12*	*12*	*05*	*15*		

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to AGN.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose AGN, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE – SA58

PROJECT REFERENCE	
Network	AGN– SA
Project No.	SA58
Project Name	GIS Upgrade
Budget Category	IT
Risk and Priority	Moderate to High, Priority 2
Reference Docs	2015 South Australia Network IT Investment Plan
Confidentiality Claim	No
PROJECT APPROVAL	
Prepared By:	Mark Wielgosz, *Business Systems & Reporting Manager, Network Systems*
Reviewed By:	Peter Butler, *Manager Network Support Services*
Approved By:	John Ferguson, *Group Executive Networks*

1 Project Overview

Rationale for Project	The current Geospatial Information System (GIS) is highly customised and becoming increasingly unstable and more difficult and expensive to maintain. The increasing instability of this system, coupled with the difficulty in obtaining support for this system (vendor support for this application ceased in 2010), means there is an increasing risk that the current system may fail (or be unavailable for a period of time), which could have implications for: • public and staff health and safety because the dial before you dig service would be unavailable; • compliance with regulatory obligations under the Retail Market Procedures; and • asset management decision making.
Options Considered	Two options were considered to address the risks outlined above: • Option 1: Do nothing, which would leave AGN exposed to a high level of health and safety, compliance and financial risk. • Option 2: Upgrade the GIS, which would mitigate the risks outlined above while also: – improving the functionality and upgrade path of the GIS application; – leveraging benefits by integrating into an Enterprise IT system architecture; and – implementing prudent and efficient end to end business processes to ensure ongoing accuracy of GIS data.
Option Selected	Option 2 has been selected because it is the most cost effective option given the risks associated with the current system.
Estimated Cost	The forecast capital expenditure for the GIS Upgrade project is $14.96 million (real $2014/15), while the forecast operating expenditure is $640,000 over the AAP (or $160,000 per annum) (real $2014/15).
Consistency with the NGR	The capital expenditure component of the GIS Upgrade project complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because it is: • necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations (rules 79(2)(i), (ii) and (iii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services. The operating expenditure component also complies with rule 91(1) because it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue providing safe and efficient supply of natural gas to our customers through detailed asset information supporting asset modelling and safe locating of our assets. More information on our stakeholder engagement program and results is provided in

	Chapter 3 of the Access Arrangement Information.

2 Background

AGN's IT systems are highly integrated, as illustrated in the IT architecture diagram below.

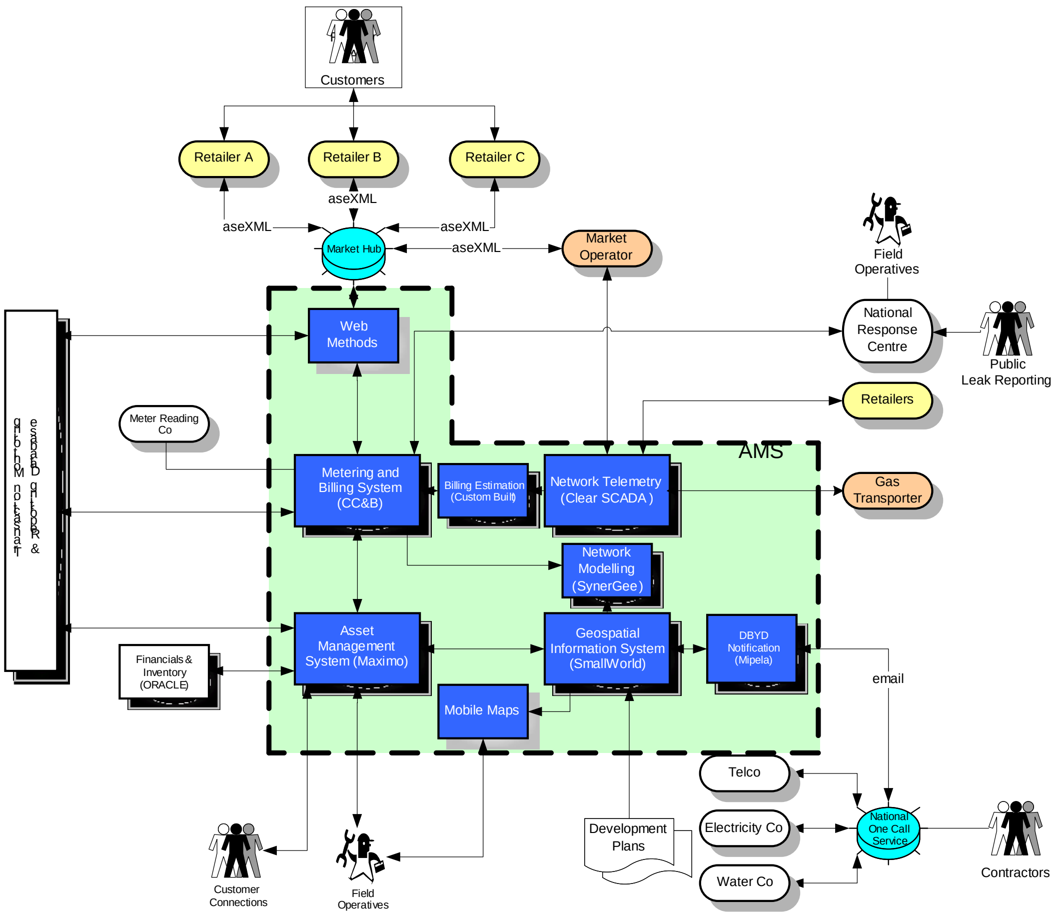


Figure 1: Networks IT architecture

These systems are utilised to provide the following business capabilities:

- Managing market transactions;
- Issue and control of field work;
- Monitoring and recording gas deliveries to customer sites;
- Emergency response;
- Monitoring network condition;
- Analysing network capacity;
- Recording the configuration and location of assets; and

- Reporting against compliance and contractual obligations.

Given their highly integrated nature, upgrades and improvements to these systems have been incorporated into a detailed Program of Work. The orderly delivery of this complete Program of Work is required to provide the full business benefits from the integrated suite of systems, including enhanced Asset Management capability, streamlined and scaled applications and processes and related risk mitigation.

The major IT system improvement projects that are to be carried out in the upcoming Access Arrangement Period (AAP) include:

- GIS Upgrade (SA58)
- Mobility Integration (SA59)
- Business Intelligence toolset (SA60)
- SA SCADA (SA62)
- Remote Meter Reading (SA64)

This business case describes the requirement for the GIS Upgrade Project. Separate business cases have been developed for the other projects listed above.

2.1 GIS Strategy

Due to the highly integrated nature and broad use of various GIS applications across the business, AGN has developed a GIS Strategy Roadmap to provide a structured approach to future GIS Projects. This roadmap is set out in Figure 2 below. As this roadmap highlights, the SA GIS Upgrade Project is scheduled to commence in July 2016.

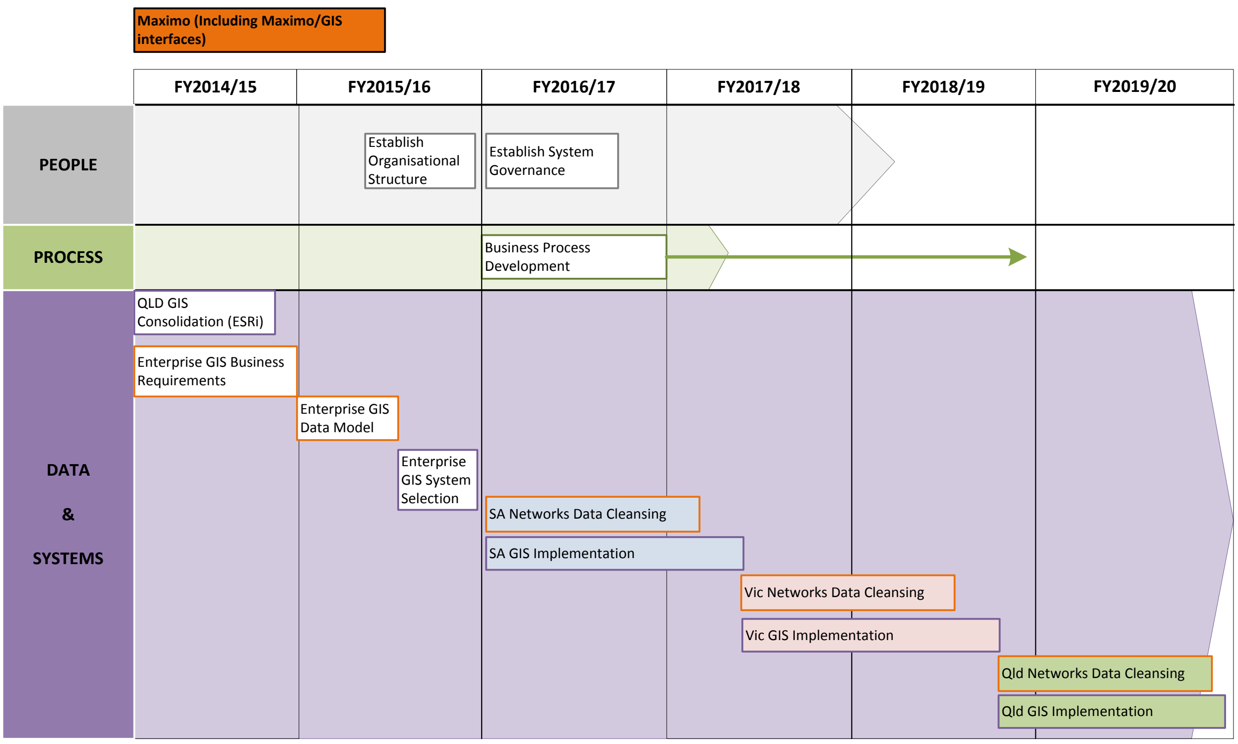


Figure 2: GIS Strategy roadmap

2.2 Existing GIS

The current Smallworld GIS application in SA plays a critical role in the management of network assets and locations. It contains a database of record for mains, regulators and valves as well as property addresses that are used in the Enterprise Asset Management (Maximo) and Metering and Billing Systems (CC&B). SmallWorld also provides key network configuration and location information for network capacity modelling and responses to external requests for the location of mains assets through Dial Before You Dig (DBYD).

Over the last ten years, Smallworld has been customised to deliver the required business functionality and, as a result, is difficult to upgrade and support due to the amount of custom code used. Due to this customisation and associated upgrade costs, software patches to improve product functionality have not been implemented and various manual workarounds have been necessary to overcome core product functional issues. This has now resulted in the current version of the Smallworld application becoming unsupported by the application vendor, which has exposed AGN to a number of significant business risks because this application is integral to critical network functions such as DBYD information, capacity modelling data and provision of retail market data.

The total cost to maintain the existing GIS application is also increasing as technical resources with experience in the unsupported version are becoming more difficult to source and relatively minor upgrades and fixes are more complex due to the level of customisation.

An upgrade or change-out of the SmallWorld application is required to mitigate the business risks and stabilise the total cost of GIS software ownership. This will be achieved by moving to a fully supported GIS application that has enhanced base functionality requiring minimal or no customisation and enables future releases to follow the standard application upgrade path.

2.3 Project scope

The GIS Upgrade project will fully implement a GIS application that will utilise the Enterprise platform, with state-specific requirements for South Australia. This Enterprise approach is considered optimal to leverage the available economies of scale across the business and aligns with the integrated structure of the network's IT systems. As detailed in the Enterprise GIS roadmap, the South Australia Project is scheduled to commence in July 2016, followed by Victoria and Queensland.

Due to the age of the existing system, the project will encompass a full implementation of a Tier 1 GIS application to provide the required base 'vanilla' functionality and will be supported by a detailed system evaluation process. This system evaluation process will include a system selection procurement exercise to ensure the GIS system selected fully addresses the business GIS requirements.

The project elements based on the Enterprise-wide and state-specific requirements for the implementation are as follows:

- Enterprise-wide:
  - system selection procurement process;

- application design and implementation (with minimal or no customisation);
- development of a new Enterprise GIS data model;
- sourcing of appropriate hardware or data centre requirements; and
- software licences.

- State-specific (SA only):
  - cleansing of existing data, including cadastre update;
  - data migration from the existing GIS into the new data model;
  - system integration into related applications (Maximo, CC&B, capacity modelling applications, mobility applications, DBYD);
  - streamlining business processes required to maintain data integrity; and
  - system training.

On completion of this project, the SA GIS application will be a fully supported, integrated enterprise application that will provide a cost effective solution to mitigate the key business risks associated with the current highly customised system, which as noted above is becoming more difficult and expensive to maintain. The upgrade will also enable:

- standardised national processes to be implemented to simplify work practices and maintain integrity of data;
- support costs to be contained because the vendor will support the current 'vanilla' version of software;
- the GIS to be integrated with the other key systems through the use of a Service Orientated Architecture; and
- future upgrade costs to be contained as the application follows the standard upgrade path.

2.4 Consistency of project with stakeholder expectations

As outlined in Chapter 3 of the AA Information, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to prudently and efficiently maintain current reliability and service levels. Consistent with the above insight, the GIS upgrade will enable AGN to continue to effectively and efficiently maintain its current business operations and service levels.

3 *Risk Assessment*

Due to the increasing instability of the current GIS and difficulty in providing adequate support to this highly customised system, there is an increasing risk of the GIS failing for a period of time and critical services not being available. The impacts of the GIS being unavailable are significant and will affect AGN's ability to safely maintain the network. The key areas that may be affected if the GIS fails include:

- Public and staff health and safety because failure of the GIS will mean AGN cannot provide accurate and timely DBYD to customers and APA's employees/contractors.
- Retailer market interactions because the GIS is the master record for meter data and address information. If GIS is not available it will affect AGN's ability to appropriately process market transactions and lead to a breach under the Retail Market Procedures.
- Asset management decision-making because if GIS data is not available for a prolonged period it will affect AGN's ability to provide information to support areas, such as capacity modelling, asset design and maintenance optimisation.

A risk assessment has been undertaken by identifying existing and potential network operational risks (and residual risks) in terms of the consequences and the likelihood of the risk. This assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. Further detail on the risk assessment that has been carried out can be found in Attachment A.

In short, the untreated risk associated with the current GIS has been assessed as high from a health and safety, compliance with relevant regulations and legislation and financial impacts perspectives, and accorded a Priority 2 rating.

4 Options considered

Two options have been identified to deal with the risks posed by the current GIS:

- Option 1 – Do nothing and continue to operate the current GIS.
- Option 2 – Upgrade the GIS.

The costs and benefits associated with these two options are summarised in the table below. As this table highlights, Option 1 will do nothing to reduce the risks associated with the current GIS and will also give rise to high ongoing maintenance costs. It is not therefore considered a viable option. Option 2, on the other hand, will reduce the risks to human health and safety and ensure that AGN continues to comply with its regulatory obligations. Over the longer run this option is also more cost effective than Option 1.[1] Option 2 has therefore been selected.

[1] Assuming a discount rate of 10%, the present value of the costs under Option 2 will be lower than the present value of the costs avoided under Option 1 after 8 years.

Costs and benefits of the options

Item	Option 1 Do Nothing	Option 2 Upgrade GIS
Costs/Risks	$2.48 million p.a. (real $2014/15)[2] (see Attachment B). High level of risk associated with system failures and outages from running an unsupported and heavily customised version of the GIS application because if the GIS fails (or is unavailable for a period of time), it will have implications for: • public and staff health and safety because the dial before you dig service would be unavailable; • potential for third party asset damage due to unavailability of asset locations; • compliance with regulatory obligations under the Retail Market Procedures; and • asset management decision making.	$14.96 million capex (real $2014/15) and $160,000 p.a. opex.
Benefits	No upfront capital costs but high ongoing maintenance costs.	Reduces the risk to human health and safety, regulatory compliance and financial risks from high to moderate (see Attachment A). Lower ongoing operating costs. Represents prudent and efficient practice, and preserves the integrity of network services.

5 *Forecast Cost for the Upcoming AAP*

The table below provide a summary of the capital and operating expenditure that is forecast to be incurred in the next AAP under Option 2. Further detail on how the capital and operating expenditure components of this forecast have been developed is provided below.

Capital and operating expenditure ($'000s real $2014/15)

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Capital expenditure (GIS Upgrade)	2,617	8,557	3,787			**14,961**
Operating Expenditure (Ongoing vendor support costs)		160	160	160	160	**640**

5.1 Capex

The GIS Upgrade Project requires a mix of external and internal IT resources.

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2 This estimate does not include the effect of any compensation claims that may occur if the GIS fails and it results in personal injury or death.

A National Networks Project cost estimate for the GIS Upgrade has been developed using the standard IT Project estimating methodology as outlined in the Project Management Methodology section of this submission.

The internal resource costs have been estimated from the bottom up by breaking the project into stages and tasks and considering the requirements (skill set and time) for each task. The hourly rates have been differentiated by resource types and are based on the current market rates for these roles. The internal labour costs include the following:

- internal project management;
- change management;
- business process re-design;
- system integration;
- business analyst and Subject Matter Expert (SME) support; and
- training.

External vendor costs have also been considered and include the following:

- external project management;
- application design;
- system build; and
- system implementation.

A significant exercise required for the GIS Upgrade is the cleansing of existing data, including implementing a new cadastre. The cost model estimate for data cleansing includes:

- realignment to a new cadastre;
- implementation of connectivity between specific assets;
- removal of duplicate and redundant data; and
- upgrading to an Enterprise data model.

The allocation of costs for the Networks-wide project elements of this project to the South Australian network has been based on the proportion of end consumers serviced by AGN's South Australian network relative to the end consumers serviced in the other jurisdictions, because the project costs are heavily dependent on data, which is, in turn, driven by the number of customers (ie, gas supply points/assets).

A key principle that has been employed when developing these internal and external resource estimates is that enterprise economies of scale achieved through utilising standardised business processes, data models, data migration techniques and existing hardware platforms should be reflected in the estimate. The table below sets out the total project cost estimate by Project Phase and includes internal and external resources and the data cleansing costs. In AGN's view, the costs in this table are both prudent and efficient and consistent with rule 74 of the National Gas Rules, which states that forecasts must be arrived at on a reasonable basis and represent the best forecast possible in the circumstances.

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	GIS Upgrade	
Project Complexity:	Complex	
Project Type:	Major Change	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
		Total Cost
End to End Total	7004	$ 14,960,880.00
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	408	$ 802,384.00
Plan Stage Total	672	$ 1,814,384.00
Deliver Stage Total	5820	$ 12,224,432.00
Close Stage Total	104	$ 119,680.00

5.2 Opex

The opex forecast assumes the following:

- The vendor support costs are based on a percentage (20%) of the licence cost. The licence cost has been obtained from a vendor quote. Note that the current vendor support costs are negligible because the current system is unsupported.
- Other operating costs such as the internal IT resources required to maintain the GIS, internal application support and data management are not expected to be materially different, so no provision has been made for changes in these costs.
- Because the upgrade just involves the replacement of an existing application, there are no additional efficiency savings associated with the project that can be netted off against these costs.

In total, operating costs are expected to rise by approximately $160,000 per annum (real $2014/15), or $0.64 million over the full AAP, as a result of the move to the fully supported GIS application. The increase in this case stems from the fact that the software vendor has provided minimal support to the Smallworld GIS application to date.

5.3 Justification for non-base year opex – capex related opex

Upgrading the GIS will, as noted above, give rise to a $0.64 million increase in operating expenditure over the AAP (or $160,000 per annum). This expenditure does not currently form part of the base year opex, nor is it reflected in the rate of change that AGN has used when applying the base step trend approach. A $0.64 million allowance for non-base year opex is therefore required to give effect to the decision to upgrade the GIS and can therefore be viewed as capex related opex.

As outlined in the following section, an upgrade of the GIS is required to maintain the safety and integrity of services and comply with existing regulatory obligations under the Retail Market Procedures, which is consistent with rule 79(1)(b) of the National Gas Rules and the longer term interests of consumers with respect to quality, safety, reliability and security of supply. The operating expenditure component of this project is also consistent with the opex criteria (see section 6) and section 24(2) of the National Gas Law, which states that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs that it incurs in providing reference services and complying with regulatory obligations. The $0.64 million allowance should therefore form part of AGN's opex forecast.

6 *Consistency with the National Gas Rules*

Consistent with the requirements of rules 79(1)(a) and 91 of the National Gas Rules, AGN considers that the capital and operating expenditure required to implement the GIS Upgrade Project is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services and comply with regulatory obligations and requirements and is of a nature that a prudent service provider would incur.
- *Efficient* – The GIS Upgrade will enable AGN to improve operational efficiency and address the high risks of non-compliance with the Retail Market Procedures and other relevant regulations and legislation, potential customer and business interruptions and corresponding adverse financial and reputation impacts. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – The GIS Upgrade project will enable AGN to operate in line with good industry practice, in terms of having all critical systems up to date and supported by vendors with minimal customisation and baseline functionality.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The GIS Upgrade Project is required to maintain an IT system that is critical to the delivery of safe and efficient pipeline services and over the medium to longer term will contribute to the achievement of the lowest sustainable cost of service delivery.

The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- Maintain and improve the safety of services (79(2)(c)(i)) – The GIS system is no longer supported and therefore has a higher risk of failing for a period of time. If the system is not available it will have safety implications for the business, particularly around the availability of DBYD information.
- Maintain the integrity of services (79(2)(c)(ii) – If the GIS is not available for a prolonged period, then it could also have implications for the integrity of services because it would mean that asset management decisions, such as capacity modelling, asset design and maintenance optimisation, could not be made.
- Comply with a regulatory obligation (79(2)(c)(iii)) – Regulatory obligations will be breached if the GIS is not available (e.g. Retail Market Procedures).

Attachment A: Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the current GIS is not upgraded, while the bottom panel sets out the residual risks if the system is upgraded. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	*Occasional*	*Rare*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	***Priority 2 121***
	Consequence	*Significant*	*Minor*	*Medium*	*Medium*	*Minor*	*Significant*	*Significant*	
	Risk Level	*High*	*Negligible*	*Moderate*	*Moderate*	*Low*	*High*	*High*	
		24	*03*	*18*	*18*	*10*	*24*	*24*	
Risk Treated	Likelihood	*Rare*	*Rare*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	***Priority 3 75***
	Consequence	*Significant*	*Minor*	*Medium*	*Medium*	*Minor*	*Significant*	*Significant*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Low*	*Moderate*	*Moderate*	
		13	*3*	*12*	*12*	*5*	*15*	*15*	
Cumulative Risk Reduction for Treated Options									***46***

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to AGNL.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose AGNL, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

Attachment B: Cost of the Do Nothing Option

The table below provides an indicative estimate of the cost of the do nothing option. The estimate includes the cost of ongoing software support (requiring specialist GIS skillset), the costs associated with rectifying consistent business interruptions and business costs associated with assets being damaged due to map data not being available for DBYD inquiries. The costs do not, however, reflect the significant reputational and financial risks associated with potential incidents resulting in injury or death when damaging the network assets.

Estimated Annual Cost of the Do Nothing Option- $'000s (FY17 to FY21)						
	FY 16/17	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
GIS Maintenance cost	80	80	80	80	80	**400**
GIS Internal IT Support	200	200	200	200	200	**1,000**
Business Interruption	200	200	200	200	200	**1,000**
Asset Damage	2,000	2,000	2,000	2,000	2,000	**10,000**
Total	**2,480**	**2,480**	**2,480**	**2,480**	**2,480**	**12,400**

BUSINESS CASE – SA59

PROJECT REFERENCE	
Network	AGN– SA
Project No.	SA59
Project Name	Mobility Integration
Budget Category	SIB Capex
Risk and Priority	Moderate, Priority 3
Reference Docs	2015 South Australia Network IT Investment Plan
Confidentiality Claim	No
PROJECT APPROVAL	
Prepared By:	Mark Wielgosz, *Business Systems & Reporting Manager, Network Support*
Reviewed By:	Peter Butler, *Manager Network Support Services*
Approved By:	John Ferguson, *Group Executive Networks*

1 Project Overview

Rationale for Project	This project will build upon the implementation of mobile collaboration and tactical mobility as part of the National Mobility Strategy and Roadmap by integrating field mobility solutions into the Enterprise IT systems. The overarching objectives of this project are to: • improve service delivery to customers through the integration and application of enterprise wide asset management and geospatial information; • automate current paper-based and manual processes; and • enable the field work force to deliver high quality and timely services through the use of mobile devices and integrated processes. If the project is not carried out, AGN and its customers and staff will be exposed to a number of operational, customer, financial and human health and safety risks. AGN will also continue to incur data entry costs, data validation and correction costs and additional field data capture and data entry costs to achieve the expected benefits of the Enterprise Asset Management (EAM) project.
Options Considered	AGN considered two options: • Option 1: Do nothing, which would leave AGN exposed to the risks outlined above and would also give rise to higher ongoing operating costs. • Option 2: Integrate mobility solutions with the Enterprise IT systems and GIS.
Option Selected	Option 2 was selected because the costs are not significantly different from Option 1 over the long run and it offers the following benefits: • it substantially reduces operational, customer, financial and human health and safety risks; • it will enable AGN to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations; and • it meets customer expectations (see stakeholder engagement comments below).
Estimated Cost	The forecast capital expenditure for the Mobility Implementation project is $8.96 million (real $2014/15), while the forecast operating expenditure over the AAP is $300,000 (real $2014/15).
Consistency with the NGR	The capital expenditure component of the Mobility Implementation project complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because it is: • necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations (rules 79(2)(i), (ii) and (iii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services. The operating expenditure component of the project is also such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services, as required by rule 91(1).

Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the Maintain theme because its implementation will allow AGN to continue providing reliable and efficient supply of natural gas to our customers by allowing the business to collect increased data on business operations and realise the benefits of the Enterprise Asset Management system project. It is also consistent with the Include theme because it will provide the foundations for future digital capabilities that AGN plans to develop to enable customers to make better decisions and provide more informed opinions.

2 Background

AGN's IT systems are highly integrated, as illustrated in the IT architecture diagram below.

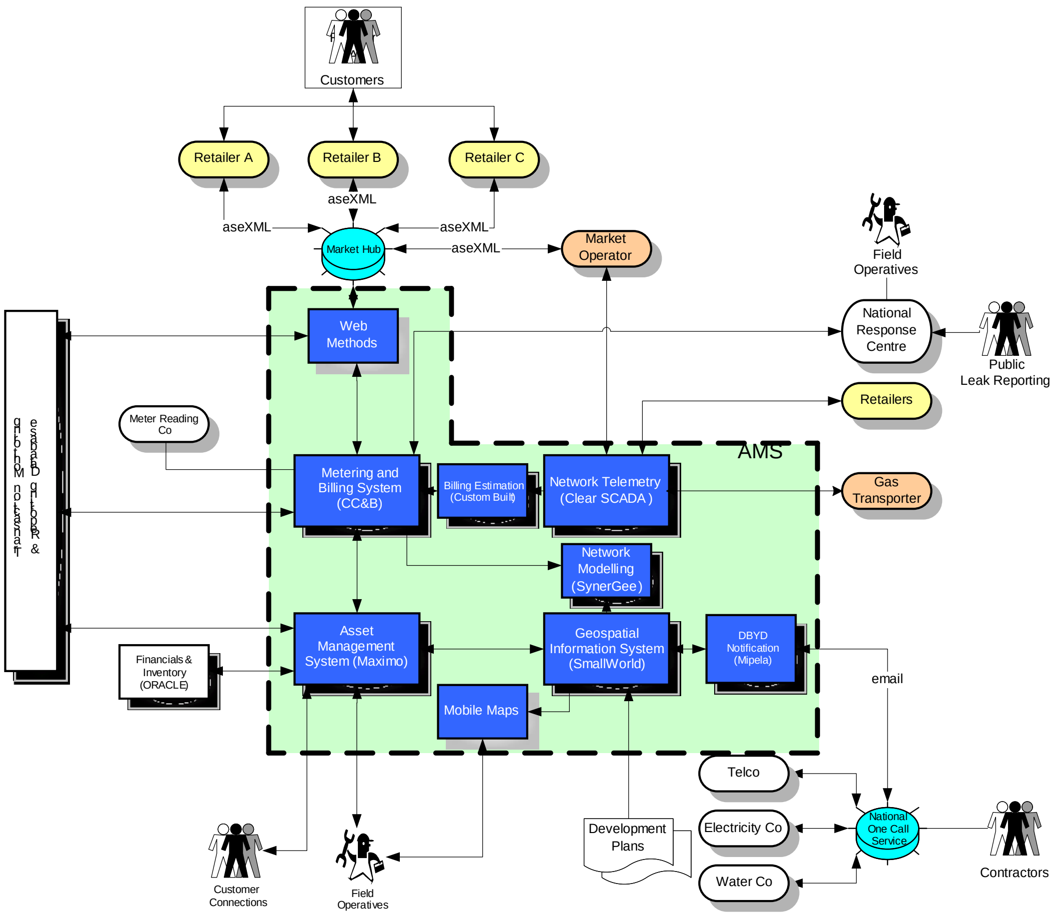


Figure 1: Networks IT architecture

These systems are utilised to provide the following business capabilities:

- Managing market transactions;
- Issue and control of field work;
- Monitoring and recording gas deliveries to customer sites;
- Emergency response;
- Monitoring network condition;

- Analysing network capacity;
- Recording the configuration and location of assets; and
- Reporting against compliance and contractual obligations.

Given their highly integrated nature, upgrades and improvements to these systems have been incorporated into a detailed Program of Work. The orderly delivery of this complete Program of Work is required to provide the full business benefits from the integrated suite of systems, including enhanced Asset Management capability, streamlined and scaled applications and processes and related risk mitigation.

The major IT system improvement projects that are to be carried out in the upcoming Access Arrangement Period (AAP) include:

- GIS Upgrade (SA58)
- Mobility Integration (SA59)
- Business Intelligence toolset (SA60)
- SA SCADA (SA62)
- Remote Meter Reading (SA64)

This business case describes the requirement for the Mobility Integration Project. Separate business cases have been developed for the other projects listed above.

2.1 Mobility Integration

Due to the potentially broad scope and highly integrated nature of mobility applications, a Mobility Strategy Roadmap has been developed. This strategy consists of three distinct phases:

1. Advanced Collaboration;
2. Tactical Mobility; and
3. Strategic (Integrated) Mobility.

These three phases are shown in Figure 2 below, along with the work to be carried out in each phase.

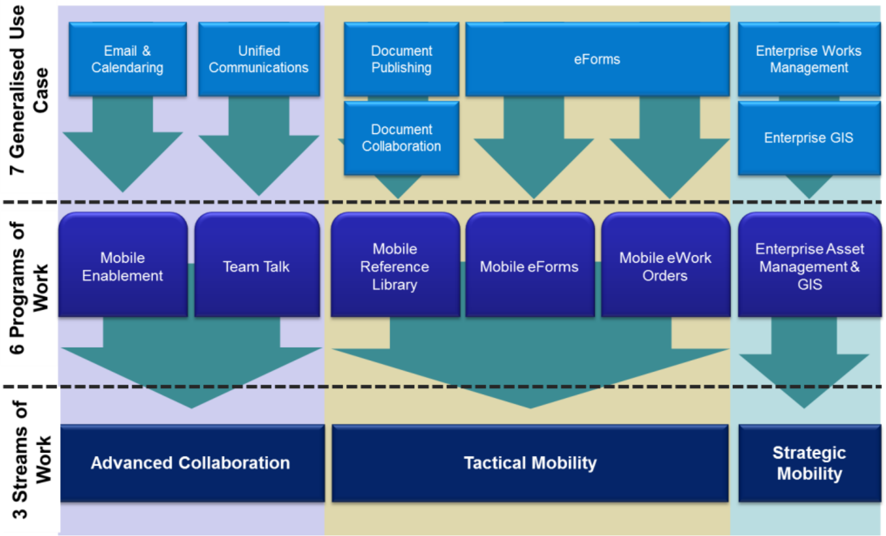


Figure 2: Mobility Strategy elements

In total there are six streams of work to be carried out under the Mobility Strategy Roadmap, which entail the following:

1. **Mobile Enablement**: Equip the workforce with Smartphone 'tools of trade' that enhance productivity by enriching communications.
2. **Team Talk**: Extend existing collaboration tools with annotation and desktop/mobile video to create a richer collaboration environment.
3. **Mobile Reference Library**: Replace the extensive collection of paper reference materials (e.g. Red/Blue books, maps, reference materials in huts) with tablets containing offline readable copies.
4. **e-Forms**: Provide a way for business groups to replace key paper forms with electronic forms that will display on a variety of mobile devices. Add new functionality to traditional forms by allowing the inclusion of photographs, exact GPS locations, immediate validation, etc.
5. **e-Work Orders**: Implement work orders as e-Forms that are electronically sent to the worker, completed in the field and sent back when complete. These will replace the current method of communicating work orders by phone and paper, but does not involve dispatch optimisation or provide integration in back-end systems.
6. **Mobility integration with Enterprise Asset Management & GIS**: Drive consistent, optimised work processes through mobile integration with the Enterprise Asset Management (Maximo) and Geospatial Information System (GIS). Improve compliance and safety outcomes through access to real time data and enterprise content.

These programs take an incremental approach to the implementation of the Mobility Strategy and each program progressively lays the foundation for the next program as the business matures in the use of mobile technology. Work on the Mobility Strategy commenced in 2012 and it is anticipated that the first five programs will be implemented by June 2016. The final program, relating to mobile integration with Asset Management (Maximo) and GIS systems is planned to start in July 2017.

The remainder of this business case focuses on the Mobility Integration project (program 6).

2.2 Project scope

The Mobility Integration project involves the integration of field mobility solutions into the Enterprise IT Systems and also recognises state-specific requirements for South Australia. The objectives of this project are to:

- enhance the mobile communications platform to enable field mobility within the workforce;
- integrate the enhanced mobile communications into the Enterprise Asset Management System (Maximo) and Geospatial Information System (GIS); and
- implement prudent and efficient end-to-end business processes that automate enterprise asset management and GIS functionality through mobility.

Ultimately this project intends to improve service delivery to customers through the integration and application of enterprise wide asset management and geospatial information, to automate current paper-based and manual processes, and enable the field work force to deliver high quality and timely services through the use of mobile devices and integrated processes.

The project elements, which are based on the Enterprise-wide and state-specific requirements for the implementation, are as follows:

- Enterprise-wide:
  - mobile device management application design and implementation;
  - integration with existing Enterprise systems (e.g. Asset Management, GIS, Payroll, HSE & Document Management); and
  - mobile works management forms (such as work orders, timesheets, audit forms and HSE checklists).
- State-specific (SA only):
  - mobile device refresh;
  - streamlining of business processes;
  - change management, including rollout of mobile solutions to contractors; and
  - mobile device and application training.

On completion of this project, AGN’s South Australian network business will be supported by a suite of mobility applications that are fully integrated into key Enterprise IT systems, such as the Asset Management System, GIS, HSE platform, payroll and document management.

The key benefits of the Mobility Integration project are outlined below:

- **Data Entry -** The SA Network currently relies on paper-based processes to capture field data, which is then manually entered into various systems, such as the Asset Management System, GIS or payroll. The Mobility Integration solution will significantly reduce manual data entry effort as the data is captured directly in the relevant system. The cost savings that are expected to be achieved from the reduced data entry are set out in section 5.2.

- **Data Integrity -** Due to the current paper-based processes to capture field data, there are significant manual data validation and error handling processes required to ensure data integrity. The Mobility Integration project will reduce the validation, error handling and correction effort as validation processes are implemented on mobile devices and field data entry processes are more tightly controlled through mobile application design. The cost savings that are expected to be achieved from the reduction in validation and error handling effort are set out in section 5.2.
- **Data Volumes –** The SA Network currently captures limited data in the field due to the cost prohibitive nature of the existing paper based processes. The Enterprise Asset Management (EAM) Project has been designed to capture more data about work on assets, as well as capturing asset and financial data at a detailed job level. This will result in significantly more data being captured in the field and will enable improved asset management decision-making, as well as improving efficiencies around reporting obligations. The benefits of the additional data have been captured within the EAM Project benefits, without reflecting the significant increased costs associated with capturing this data utilising existing paper-based processes. These increased costs are due to additional time to capture data in the field using paper processes as well as subsequent data entry of the additional data. The Mobility Integration project will enable these increased costs to be avoided. The avoided costs are set out in section 5.2. The improvements in field data and increased data volumes will also enable the business to more effectively leverage the benefits of the Business Intelligence toolset as discussed in the IT Program of Work and detailed further in the Business Intelligence business case (SA60).
- **Technical, Regulatory and Legislative Compliance Obligations –** The SA Network has a suite of management systems implemented to ensure compliance with a variety of technical, regulatory and legislative obligations. These obligations include Health & Safety legislation, technical regulations and regulatory requirements such as Retail Market Procedures and the National Energy Retail Law and Rules. These management systems are supported by the related IT systems, such as the Asset Management System, GIS and HR systems to provide relevant information to meet these compliance obligations. Improvements in the timing and integrity of data will also streamline reporting to ensure compliance obligations are met and reported appropriately.
- **Health & Safety -** The implementation of the mobility solution will enhance network health and safety from a public and employee perspective. Public safety will be improved through improved response to emergencies and access to accurate asset data such as Dial Before You Dig (DBYD) information. Employee and contractor safety will be improved through access to improved asset data, streamlined safety tools and processes and live access to corporate knowledge, such as latest version of technical work instructions. Improved asset data will also enhance asset management decision-making, including targeted maintenance and asset replacement activities to maintain asset integrity.

2.3 Consistency of project with stakeholder expectations

As outlined in Chapter 3 of the AA Information, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to prudently and efficiently maintain current reliability and service levels. They also told us that they want AGN to involve and include them by increasing the transparency of AGN's operations, to help them make better decisions and provide more informed opinions.

Consistent with the above insights, the Mobility integration project will enable AGN to continue to provide reliable and efficient supply of natural gas to customers by allowing the business to collect increased data on business operations and realise the benefits of the Enterprise Asset Management system project. It will also provide the foundations for future digital capabilities that AGN plans to develop to enable customers to make better decisions and provide more informed opinions.

3 Risk Assessment

The risks of not proceeding with the Mobility Integration project include:

- Operational and customer risks of slower responses and restoration times to work orders due to continued inefficiencies of the more manual paper based processes.
- Operational risks from not being able to extract and interrogate the data that is available with mobile devices and use this to make improved business decisions.
- Financial risk from not gaining the efficiencies in operations and improved decision making that mobility may allow.
- Operational risks of errors in manual processes of data compared to mobile communications.
- Health and safety risks from a number of events that could be mitigated with the information and controls that mobility provides. This includes:
  - Operational staff not following step processes for safety before undertaking any work - mobile application can force a check list of processes to be followed.
  - Insufficient safety information available in real time to field crew.
  - Inability to capture project HSE risks - additional tool to raise HSE potential risks will make it much quicker and likely to be applied.
  - Understanding of the assets - pictorial representation of the asset can reduce the likelihood of safety incident.
  - Reduced time to attend public safety incidents - with mobility AGN would know the location of each crew and can use this to allocate personnel to any incident that arises.

AGN has carried out a risk assessment using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. This has entailed identifying existing and potential network operational risks (and residual risks) in terms of the consequences and the likelihood of the risk. Further detail on the risk assessment that has been carried out can be found in Attachment A.

In short, the untreated risk associated with the matters outlined above has been assessed as moderate from a health and safety, operational, customer and financial perspectives, and accorded a Priority 3 rating.

4 Options

Two options have been identified to deal with the risks outlined above:

- Option 1 – Do nothing.
- Option 2 – Integrate the mobility solutions with Enterprise Asset Management and GIS.

The costs and benefits associated with these two options are summarised in the table below.

Table 1: Costs and benefits of the options

Item	Option 1 Do Nothing	Option 2 Mobility Integration
Costs/Risks	\$2.85 million opex over AAP (real \$2014/15) (see table 4 – cost savings + cost avoidance) The lack of integration of the mobility solution leaves AGN with an investment in mobile devices and point solutions in the field that cannot leverage the potential for improved safety and customer service levels, as well as benefits from avoiding field data capture costs. It also means that AGN, customers and staff/contractors will continue to be exposed to the operational, customer, financial and human health and safety risks outlined in Section 3.	\$8.96 million capex + \$0.3 million non-recurring opex over the AAP (real \$2014/15).
Benefits	No upfront capital costs but ongoing data entry, data validation and correction costs and additional costs for field data capture and additional data entry that are avoided under Option 2.	Reduces the risks outlined in section 3 from moderate to low (see Attachment A). Leverages the collaboration and access to the mobile reference library, enables the automation of manual processes, and improves safety and service levels through best practice application of integrated enterprise asset systems and location based services. Enables \$0.6 million of cost savings to be achieved in this AAP and a further \$2.25 million of costs to be avoided in this AAP.

As this table highlights, the do nothing option is costly, both in terms of:

- the operating expenditure that will have to be incurred if the Mobility Integration project doesn't proceed, which includes ongoing data entry costs, data validation and correction costs and additional field data capture and data entry costs that have not been included in the EAM project costs (see section 2.1 and Table 4); and
- the inability of the field work force to deliver high quality and timely services to customers through the use of mobile devices and integrated processes and for AGN to achieve other operational efficiencies.

It also leaves AGN, customers and staff/contractors exposed to a number of operational, customer, financial and human health and safety risks (see section 3 and Attachment A).

Option 2, on the other hand, involves higher upfront capital cost but has a number of significant benefits including:

- mitigating the operational, customer, financial and human health and safety risks set out in section 3;
- allowing customers to benefit from significant operational efficiencies and to avoid additional data costs;
- enabling AGN to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations; and
- meeting customer expectations (see stakeholder engagement comments).

When coupled with the fact that the costs under Option 2 are not significantly different from Option 1 over the longer run than Option 1, a decision has been made to proceed with Option 2.

5 *Forecast Cost for the Upcoming AAP*

The table below provide a summary of the capital and operating expenditure that is forecast to be incurred in the next AAP under the Mobility Integration Project. Further detail on how the capital and operating expenditure components of this forecast have been developed is provided below.

Table 2: Capital and operating expenditure ($'000s real $2014/15 – excluding overheads)

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	**Total**
Capital Expenditure (Mobility Integration)	0	1,866	2,099	2,798	2,194	**8,958**
Net Operating Expenditure (Gross Operating Expenditure less cost savings)	0	0	200	100	0	**300**

5.1 Capex

The SA Mobility Integration Project requires a mix of both internal and external IT resources.

An Enterprise Project cost estimate for the Mobility Integration Project has been developed using the standard IT Project estimating methodology as outlined in the Project Management Methodology section of this submission. The internal resource costs have been estimated from the bottom up by breaking the project into stages and tasks and considering the requirements (skill set and time) for each task. The hourly rates are differentiated by resource types and are based on the current market rates for these roles. The internal labour costs include the following:

- internal project management;
- change management;
- business process re-design;
- system integration;

- business analyst and Subject Matter Expert (SME) support; and
- training.

External vendor costs have also been considered and include the following:

- external project management;
- application design;
- system build; and
- system implementation.

The cost estimate developed is based on an Enterprise implementation of the Mobility Integration Project across AGN. To determine what portion of these costs should be attributed to the SA Network, AGN has used the following allocation methodology:

- the initial allocation of costs to AGN's Network business has been based on the proportion of mobility users across AGN that are working within the Network business (80%); and
- the subsequent allocation to the South Australian Network business has been based on the proportion of mobility users operating within this network business (40%).

The application of this methodology resulted in 32% of the Enterprise-wide costs being allocated to the South Australian Network business.

A key principle that has been employed when developing these estimates is that enterprise economies of scale achieved through utilising standardised business processes, data models, data migration techniques and existing hardware platforms should be reflected in the estimate. The table below sets out the total project cost estimate by Project Phase, including both internal and external resources. In AGN's view, the costs in this table are both prudent and efficient and consistent with rule 74 of the National Gas Rules, which states that forecasts must be arrived at on a reasonable basis and represent the best forecast possible in the circumstances.

Table 3: Mobility Integration Capex by stage

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Mobility Integration	
Project Complexity:	Complex	
Project Type:	Major Change	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	4068.8	$ 8,957,836.80
Estimations by Project Stage		
Develop Stage Total	224	$ 314,688.00
Plan Stage Total	536	$ 1,551,616.00
Deliver Stage Total	3225.6	$ 6,995,788.80
Close Stage Total	83.2	$ 95,744.00

5.2 Opex

As outlined in section 2.2, the implementation of the Mobility Integration project is expected to result in:

- operating cost savings due to reduced data entry as well as data validation and correction; and
- the avoidance of field data capture and additional data entry costs that would otherwise be required to achieve the benefits of the EAM project, but which were not factored into the forecast cost of this project.

The value of these benefits are set out in the table below, along with the IT support costs that are forecast to be incurred. These forecasts have been calculated assuming the following:

- IT support costs – the IT support cost forecast assumes that another two[1] FTEs are required to support Mobility at a cost of $150,000 per employee ($300,000 in total). At present, there is one FTE supporting a small number of mobility apps, but there will be a significant increase in apps with Mobility Integration.
- Operating cost savings – this forecast assumes that the FTEs that are currently used to manually enter data will fall as the mobility project rolls out the apps over a four year period, starting with one FTE in 2017/18 ($100,000 salary) and rising to ultimately to three FTEs by 2020/21. This saving also extends beyond the AAP.
- Cost avoidance – EAM has introduced additional data capture requirements because we have extra workorders, individual Purchase Orders (rather than blanket Purchase Orders) and additional asset attribute data being collected. Assuming approximately 100,000 work orders per year in SA and a 5 minute saving per workorder in the field (considered minimal) and 3 minutes in data entry, this will avoid approximately:
  - 8,333 hrs @ $60 per hour in the field (average hourly rate including on costs for field staff), which results in a saving of $500,000; and
  - 5,000 hours @ $50 per hour in data entry (average hourly rate including on costs for data entry staff), which results in a saving of $250,000.

[1] **At present, there is** one FTE supporting a small number of mobility apps, but there will be a significant increase in apps with Mobility Integration.

Table 4: Operating expenditure benefits and costs ($'000s real $2014/15)

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Cost Savings - Current data entry - Data validation and correction	0	0	(100)	(200)	(300)	**(600)**
IT Support Costs - Mobility platform support - Mobility application support	0	0	300	300	300	**900**
Net Opex costs	**0**	**0**	**200**	**100**	**0**	**300**
Cost Avoidance - Field data capture - Additional data entry	0	0	(750)	(750)	(750)	(2,250)
TOTAL Net Benefits	**0**	**0**	**(550)**	**(650)**	**(750)**	**(1,950)**

As the final row of this table highlights the benefits of this project are assumed to progressively be realised as the project is implemented from FY18 to FY21 with a net benefit (measured from an operating cost perspective) of $1.95 million expected to be achieved by the end of the AAP. The other important points to note from this table are that:

- the operational cost savings will offset a significant proportion of the increase in IT support costs in 2018/19 and 2019/20 and by 2020/21 will completely offset these costs; and
- the avoided costs have not been deducted from the IT support costs, because as noted above the costs associated with capturing data were not included in the EAM project and so do not form part of AGN's forecast for the upcoming period.

The dark shaded row in this table sets out the net opex requirement for the upcoming AAP, which is just $300,000. Because the operational cost savings completely offset the IT support costs by the end of the AAP, this expenditure can be considered non-recurrent.

5.3 Justification for non-base year opex – capex related opex

The Mobility Integration project will, as noted above, give rise to a one off $300,000 increase in operating expenditure over the AAP. This expenditure does not currently form part of the base year opex, nor is it reflected in the rate of change that AGN has used when applying the base step trend approach. A $0.3 million allowance for non-base year opex is therefore required to give effect to the decision to implement the Mobility Integration project and can therefore be viewed as capex related opex.

As outlined in section 6, the Mobility Integration Project is required to maintain the safety and integrity of services and comply with existing technical, regulatory and legislative obligations under the Retail Market Procedures. This is consistent with both rule 79(1)(b) of the National Gas Rules and the longer term interests of consumers, with respect to quality, safety, reliability and security of supply. The operating expenditure component of this project is also consistent with the opex criteria (see section 7) and section 24(2) of the National Gas Law, which states that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs that it incurs in providing reference services and complying with regulatory obligations. The $0.3 million allowance should therefore form part of AGN's opex forecast for the upcoming AAP.

6 *Consistency with the National Gas Rules*

Consistent with the requirements of rules 79(1)(a) and 91 of the National Gas Rules, AGN considers that the capital and operating expenditure required to implement the Mobility Integration in South Australia is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services and comply with regulatory obligations and requirements and is of a nature that a prudent service provider would incur.
- *Efficient* – The Mobility Integration Project is cost effective and will enable AGN to improve operational efficiency and minimise the risk to human health and safety, customer and business interruptions and corresponding adverse financial and reputation impacts. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – It is good practice to seek to continue to develop service levels in-line with opportunities from new technology. This is demonstrated by recent applications by other network businesses in both the gas and electricity distribution sectors for implementation of mobility applications.[2]
- *To achieve the lowest sustainable cost of delivering pipeline services* – The integration of mobility solutions will reduce manual processing and costs and will assist with the provision of improved data for decision making. It will therefore contribute to the achievement of the lowest sustainable cost of delivering pipeline services.

The proposed capital expenditure is also consistent with rule 79(1)(b), because it is necessary to:

- Maintain and improve the safety of services (79(2)(c)(i)) – The Mobility Integration project offers a number of opportunities to reduce health and safety risk to both the workforce and to the public as outlined in section 2.2.
- Maintain the integrity of services (79(2)(c)(ii) – The Mobility Integration project will allow more accurate data to be extracted and utilised for improved decision making. There will also be less operational errors from manual processing of data, which will improve the integrity of the services provided.
- Comply with a regulatory obligation (79(2)(c)(iii)) – The Mobility Integration project will overcome the delays in service provision and meeting regulatory obligations and will also ensure that data is available to demonstrate compliance.

[2] Examples include SA Power Networks IT Field Force Mobility Business Case submitted as part of their 2014 proposal for their determination covering 2015-20. The AER's November 2014 draft determination for Jemena's Gas network in NSW supported their adoption of a field mobility solution

Attachment A: Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the Mobility Integration project is not carried out, while the bottom panel sets out the residual risks if the project is undertaken. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

Low		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	*Likely*	*Rare*	*Frequent*	*Frequent*	*Rare*	*Unlikely*	*Frequent*	***Priority 3***
	Consequence	*Minor*	*Insignificant*	*Minor*	*Minor*	*Insignificant*	*Minor*	*Minor*	
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Negligible*	*Low*	*Moderate*	
		17	*1*	*19*	*19*	*1*	*5*	*19*	***81***
Risk Treated – Mobility Integration Project	Likelihood	*Unlikely*	*Rare*	*Unlikely*	*Unlikely*	*Rare*	*Unlikely*	*Unlikely*	***Priority 4***
	Consequence	*Minor*	*Insignificant*	*Minor*	*Minor*	*Insignificant*	*Minor*	*Minor*	
	Risk Level	*Low*	*Negligible*	*Low*	*Low*	*Negligible*	*Low*	*Low*	
		5	*1*	*5*	*5*	*1*	*5*	*5*	***27***
								Cumulative Risk Reduction for Option 1	***44***

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to AGNL.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose AGNL, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE – SA60

PROJECT REFERENCE	
Network	AGN– SA
Project No.	SA60
Project Name	Business Intelligence
Budget Category	SIB Capex
Risk and Priority	Moderate
Reference Docs	2015 South Australia Network IT Investment Plan
Confidentiality Claim	No
PROJECT APPROVAL	
Prepared By:	Mark Wielgosz, *Business Systems & Reporting Manager, Network Support*
Reviewed By:	Peter Butler, *Manager Network Support Services*
Approved By:	John Ferguson, *Group Executive Networks*

1 Project Overview

Rationale for Project	This project involves the implementation of a Business Intelligence Toolset, to provide improved information and reporting utilising the data from disparate IT applications used within the business. The overarching objectives of this project are to provide a toolset that will improve data quality, streamline reporting effort and allow greater access to information for optimised decision making. If the project is not carried out then AGN and its customers and staff will be exposed to a number of operational, compliance, financial and potential human health and safety risks. AGN will also continue to incur relatively high data analysis and reporting costs and additional data analysis, reporting data validation and correction costs to achieve the expected benefits of the Enterprise Asset Management (EAM) project.
Options Considered	AGN considered two options: • Option 1: Do nothing, which would leave AGN exposed to the risks outlined above and would also give rise to higher ongoing operating costs. • Option 2: Implement a Business Intelligence Solution.
Option Selected	Option 2 was selected because it will: • allow customers to benefit from significant operational efficiencies and to avoid additional data and reporting costs; • improve data quality, streamlining reporting and enabling more informed decision making to occur and in doing so, enabling AGN to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations; • reduce the operational, customer, financial and potential human health and safety risks; and • meet customer expectations (see stakeholder engagement comments).
Estimated Cost	The forecast capital expenditure for the Business Intelligence Toolset project is $8.56 million (real $2014/15).
Consistency with the NGR	The capital expenditure associated with the Business Intelligence Toolset project complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because it is: • necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations (rules 79(2)(i), (ii) and (iii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will allow AGN to continue providing reliable and efficient supply of natural gas to our customers by allowing the business to analyse and utilise increased data resulting from the Enterprise Asset Management and Mobility Integration projects as well as fulfilling compliance obligations. It is also consistent with the Include theme because it will provide the foundations for future digital capabilities that AGN plans to develop to enable customers to make better decisions and

	provide more informed opinions.

2 Background

AGN’s IT systems are highly integrated, as illustrated in the IT architecture diagram below.

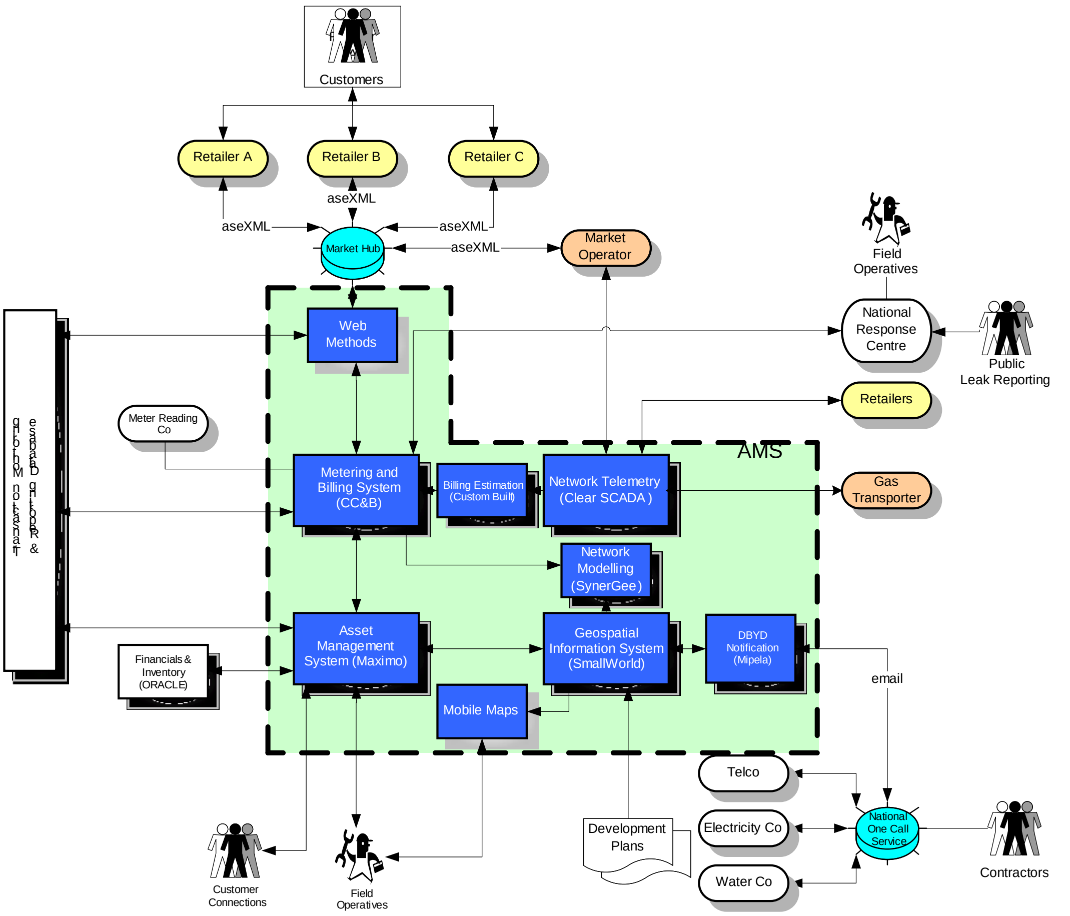


Figure 1: Networks IT architecture

These systems are used to provide the following business capabilities:

- Managing market transactions;
- Issue and control of field work;
- Monitoring and recording gas deliveries to customer sites;
- Emergency response;
- Monitoring network condition;
- Analysing network capacity;
- Recording the configuration and location of assets; and
- Reporting against compliance and contractual obligations.

Given their highly integrated nature, upgrades and improvements to these systems have been incorporated into a detailed Program of Work. The orderly delivery of this complete Program of Work is required to provide the full business benefits from the integrated suite of systems, including enhanced Asset Management capability, streamlined and scaled applications and processes and related risk mitigation.

The major IT system improvement projects that are to be carried out in the upcoming Access Arrangement Period (AAP) include:

- GIS Upgrade (SA58)
- Mobility Integration (SA59)
- Business Intelligence Toolset (SA60)
- SA SCADA (SA62)
- Remote Meter Reading (SA64)

This business case describes the requirement for the Business Intelligence Toolset Project. Separate business cases have been developed for the other projects listed above.

2.1 Business Intelligence Toolset

Due to the breadth, size and complex nature of the IT systems and challenges associated with introducing a business intelligence platform, AGN has developed an Enterprise Information Management (IM) Strategy & Roadmap.

During the development of the Enterprise Information Management Strategy, the following information management issues were identified:

- Information is sometimes difficult to access.
- Excessive manual work can be required to collate, consolidate and disseminate information.
- Lack of guidelines on information management.
- Information is sometimes fragmented across business lines and systems.
- Extensive manual data manipulation causes duplication of effort and gives rise to manual errors.

The key outcomes from the strategy development is the implementation of a Business Intelligence Toolset (specifically a 'Selective Enterprise Data Repository' application), in conjunction with well-defined data management and analytics and reporting frameworks.

The Enterprise Information Management roadmap is set out in Figure 2 below.

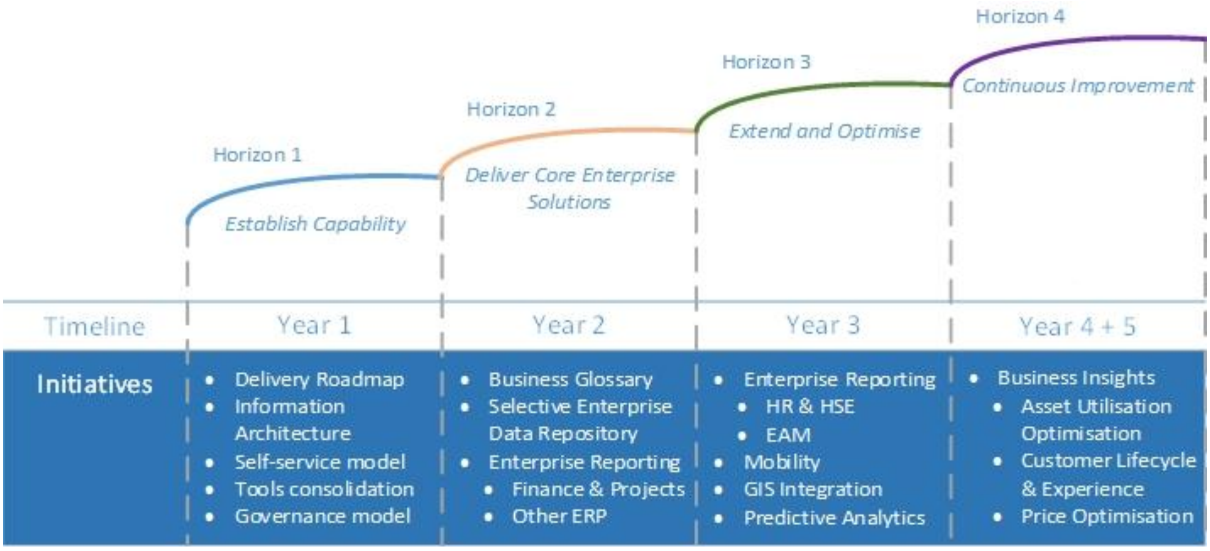


Figure 2: Business Intelligence Strategy roadmap

2.2 Project scope

The overarching objectives of the Business Intelligence Toolset project are to:

- implement a toolset that allows consolidated views of disparate sets of data from multiple IT applications;
- drive improved decision making through additional access to information;
- streamline reporting through standardised reporting tools;
- provide integration into other Enterprise business applications to provide ease of publishing information; and
- implement prudent and efficient end to end business processes to maintain and improve data quality.

Given the enterprise and fully integrated nature of the AGN's IT systems, the Business Intelligence Project will be rolled out across the networks, with the South Australia Networks requirements being delivered through business intelligence functionality applied to South Australia data. Work on this project is scheduled to commence in July 2016 and be rolled out over a four-year period.

The roadmap has identified a set of initiatives that will be delivered by the Business Intelligence Project, including:

- Establishing the Enterprise Information Architecture, including development of the information architecture model and implementation into existing systems.
- Procuring and implementing a 'Selective Enterprise Data Repository' (SEDR) application as the central business intelligence tool.
- Establishing the required reporting and analytics tools, including implementation of a standardised 'self-service reporting' framework.

- Establishing a data quality framework, including associated changes to business processes and human resource impacts.
- System training, including upskilling of existing business analysts and general business users for 'self-service reporting'.

The use of a Selective Enterprise Data Repository has been chosen to allow for an incremental rollout of the Business Intelligence functionality as the various Enterprise IT Systems are brought into the Business Intelligence framework. As a result, the project is forecast to be rolled out over a four-year period.

On completion of this project, the Business Intelligence Toolset will improve data quality, streamline reporting effort and allow greater access to information for optimised decision making.

The key benefits of the Business Intelligence project include:

- **Increased data analysis -** As a result of the Enterprise Asset Management (EAM) and the proposed Mobility Integration project, there will be a significant increase in the volume of data available to drive improved work management. This data will include detailed information on contractor costs, internal resource planning and scheduling and work-related asset data. This data has been identified in the EAM Project benefits as critical to achieving improved works management. To support the EAM benefits realisation, the Business Intelligence Toolset is required to fully realise those benefits as well as avoid data analyst costs associated with the increased analysis required to realise the EAM benefits. Estimates of the EAM benefits being facilitated by the Business Intelligence Toolset, as well as the data analyst costs avoided are set out in section 5.2.
- **Improved reporting –** AGN's SA Networks currently require the collation of significant amounts of data from various IT applications, such as Maximo Works Management, Oracle Financials and Customer Care & Billing. This data is then subject to manual manipulation to provide the appropriate reporting to relevant stakeholders, including external clients, internal management and industry regulators. These processes result in duplication of effort, increased potential for manual errors and also give rise to difficulties in disseminating the information in a timely manner.

  These reporting issues are expected to become more pronounced as the Mobility Integration Project is implemented and there is an increase in the volume of data being collated. The Business Intelligence project will also provide the following reporting benefits:

  - Consolidating views of data from various systems to enable cross-functional reporting.
  - Enabling the same data to be presented multiple stakeholders in different views.
  - Improving the dissemination of reporting information, including the implementation of 'self-service' reporting.
  - Providing a platform for advanced visualisation of data through the Geospatial information System (GIS) application.
  - Enabling data to be reported and presented in a consistent manner.

- Providing an agile reporting platform to facilitate changing reporting requirements from key stakeholders, including external clients and industry regulators.

  There is also a cost avoidance benefit in implementing the Business Intelligence Toolset in conjunction with the Mobility Integration and EAM projects, because it will reduce the effort associated with reporting, including data validation and correction as well as producing and transmitting those reports. The avoided costs are set out in section 5.2.

- **Improved decision-making capability –** The current manual and disparate reporting processes within AGN's SA Networks results in difficulties in combining cross-functional data to enable consolidated business decision-making. The manual nature of the processes and data quality issues also result in business analysts focusing on the production of reports, rather than detailed analysis to enable improved decision-making. The Business Intelligence project will improve decision-making capability by:
  - consolidating cross-functional data to provide detailed business-wide information;
  - streamlining the reporting processes and introducing a data quality framework that will enable business analysts to focus on analytics;
  - providing analytical tools to business analysts;
  - providing self-service reporting to enable agile decision-making; and
  - implementing Business Intelligence tools to enable analysis of the increased volume and complexity of data provided through the EAM and Mobility Integration projects.
- **Improved data quality** - A significant amount of data is currently recorded on paper and manually entered into various systems such as Maximo, Customer Care & Billing and Oracle Financials in AGN's SA Networks. The Business Intelligence project will improve decision-making capability by:
  - introducing a data quality framework; and
  - improving the capability of staff to analyse data, including data quality analysis.

2.3 Consistency of project with stakeholder expectations

As outlined in Chapter 3 of the AA Information, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to prudently and efficiently maintain current reliability and service levels. They also told us that they want AGN to involve and include them by increasing the transparency of AGN's operations, to help them make better decisions and provide more informed opinions.

Consistent with the above insights, the Business Intelligence project will enable AGN to continue to provide reliable and efficient supply of natural gas to customers by allowing the business to analyse and utilise increased data resulting from the Enterprise Asset Management and Mobility Integration projects as well as fulfilling our compliance obligations. It will also provide the foundations for future digital capabilities that AGN plans to develop to enable customers to make better decisions and provide more informed opinions.

3 *Risk Assessment*

The risks of not implementing the Business Information Toolset include:

- operational risks from not being able to quickly interrogate the data using predictive analysis and use this to make improved business decisions;
- compliance risk because the reports required for regulatory requirements cannot be quickly provided and there is also a risk of data processing errors;
- financial risk from not having detailed accurate status reports readily available; and
- potential health and safety risks from not being able to access all available information when determining appropriate strategies.

AGN has carried out a risk assessment using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. This has entailed identifying existing and potential network operational risks (and residual risks) in terms of the consequences and the likelihood of the risk. Further detail on the risk assessment that has been carried out can be found in Attachment A.

In short, the untreated risk associated with the matters outlined above has been assessed as moderate from a compliance perspective, and accorded a Priority 3 rating.

4 Options

Two options have been identified to deal with the risks outlined above:

- Option 1 – Do nothing and continue with the current processes.
- Option 2 – Implement a Business Intelligence Solution.

The costs and benefits associated with these two options are summarised in the table below.

Table 1: Costs and benefits of the options

<table>
<tr><th>Item</th><th>Option 1
Do Nothing and continue with current processes</th><th>Option 2
Business Intelligence Solution</th></tr>
<tr><td>Costs/Risks</td><td>Continuing with current processes is not considered prudent given the issues associated with reporting in information silos and the manual nature of those processes, which restricts optimal business decision-making and potentially results in data and reporting errors.

It will also mean that:
AGN continues to incur relatively high ongoing data analysis and reporting costs and additional costs for data analysis and reporting data validation and correction that are avoided under Option 2, which together amount to $0.3 million p.a. (real $2014/15) (see Table 4).
AGN is unable to realise some of the EAM benefits, which is estimated be around $0.34 million p.a. (real $2014/15 (see Table 4).
AGN, customers and staff/contractors will continue to be exposed to the operational, compliance, financial and potential human health and safety risks outlined in Section 3.</td><td>$8.56 million capex ($2014/15).</td></tr>
<tr><td>Benefits</td><td>No upfront capital costs but relatively high ongoing operating costs.</td><td>The project will:
Improve data quality, streamline reporting and enable more informed decision making to occur.
Take advantage of the increasing volumes of data being captured in disparate systems as well as deliver constantly changing reporting requirements to key stakeholders.
Reduce the risks outlined in section 3 (see Attachment A).
Provides for significant cost savings and cost avoidance.</td></tr>
</table>

As this table highlights, the do nothing option is costly, both in terms of:

- the operating expenditure that will have to be incurred if the Business Intelligence Toolset project doesn't proceed, which includes ongoing data analysis and reporting costs and additional data analysis and reporting data validation and correction costs that have not been included in the EAM project cost (see section 2.1); and
- the inability to yield all of the benefits of the EAM project.

It also leaves AGN, customers and staff/contractors exposed to a number of operational, compliance, financial and potential human health and safety risks (see section 3 and Attachment A).

Option 2, on the other hand, involves higher upfront capital cost but has a number of significant benefits including:

- allowing customers to benefit from significant operational efficiencies and to avoid additional data and reporting costs;
- improving data quality, streamlining reporting and enabling more informed decision making to occur and in doing so, enabling AGN to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations;
- reducing the operational, customer, financial and human health and safety risks set out in section 3; and
- meeting customer expectations (see stakeholder engagement comments).

Given the nature of these benefits, Option 2 has been selected.

5 *Forecast Cost for the Upcoming AAP*

The table below provide a summary of the capital and operating expenditure that is forecast to be incurred in the next AAP under the Business Intelligence Toolset Project. Further detail on how the capital and operating expenditure components of this forecast have been developed is provided below.

Table 2: Capital and operating expenditure ($'000s $2014/15 – excluding overheads)

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	**Total**
Capital Expenditure (Business Intelligence)	0	1,976	3,895	2,597	96	**8,564**
Net Operating Expenditure (Gross Operating Expenditure less cost savings)	**0**	**0**	**0**	**0**	**0**	**0**

5.1 Capex

The Business Intelligence Project requires a mix of external and internal IT resources.

An Enterprise Project cost estimate for the Business Intelligence Project has been developed using the standard IT Project estimating methodology as outlined in the Project Management Methodology section of this submission. The internal resource costs have been estimated from the bottom up by breaking the project into stages and tasks and considering the requirements (skill set and time) for each task. The hourly rates are differentiated by resource types and are based on the current market rates for these roles. The internal labour costs include the following:

- internal project management;
- change management;
- business process re-design;
- system integration;

- business analyst and Subject Matter Expert (SME) support; and
- training.

External vendor costs have also been considered and include the following:

- external project management;
- application design;
- system build; and
- system implementation

The cost estimate developed is based on an Enterprise implementation of the Business Intelligence project across AGN. To determine what portion of these costs should be attributed to the SA Network, AGN has used the following allocation methodology:

- The initial allocation of 80% of the enterprise wide costs to AGN's Networks business reflects the high degree of network-specific applications (including GIS and CC&B) accommodated by the Toolset, the proportionately higher volume of data generated by the Network business and the significant analysis and reporting requirements of the Network business.
- The subsequent allocation of 40% of the AGN Networks business costs to the South Australian Network business has been based on the data and reporting requirements of this business *vis-à-vis* other parts of the Network business.

The application of this methodology resulted in 32% of the Enterprise-wide costs being allocated to the South Australian Network business.

A key principle that has been employed when developing these internal and external resource estimates is that enterprise economies of scale achieved through utilising standardised business processes, data models, data migration techniques and existing hardware platforms should be reflected in the estimate. The table below sets out the total project cost estimate by Project Phase, including both internal and external resources. In AGN's view, the costs in this table are both prudent and efficient and consistent with rule 74 of the National Gas Rules, which states that forecasts must be arrived at on a reasonable basis and represent the best forecast possible in the circumstances.

Table 3: Business Intelligence Toolset Capex by Stage

IT & ICT Procurement Estimations Template: B&T Projects			
Project Name:	BI Platform		
Project Complexity:	Complex		
Project Type:	Major Change		
Estimations Summary			
Total Project (end to end)	Effort (Days)	Total Cost	
End to End Total	2233.6	$ 8,563,658.68	
Estimations by Project Stage			
		Stage Cost	
Develop Stage Total	268.8	$ 370,585.60	
Plan Stage Total	345.6	$ 1,605,137.60	
Deliver Stage Total	1536	$ 6,492,191.48	
Close Stage Total	83.2	$ 95,744.00	

5.2 Opex

As outlined in section 2.2, the streamlining of processes and more robust business intelligence toolsets is expected to result in:

- operating cost savings in data analysis and reporting; and
- the avoidance of additional data analysis and reporting data validation and correction that would otherwise be required to achieve the last 20% of the benefits of the EAM project.

The value of these benefits are set out in the table below along with the IT support costs that are forecast to be incurred. These forecasts have been calculated assuming the following:.

- IT support costs – the IT support cost forecast assumes that another FTE is required to manage the BI toolset at a cost of $150,000 p.a..
- Operating cost savings – this forecast assumes that a Business Analyst (cost $150,000 p.a.) that would otherwise be required to develop reports, correct data, validate data etc is no longer required because the processes are streamlined.
- Cost avoidance – the avoided costs relates to the realisation of the last 20% of the EAM benefits. The BI toolset is required to realise these benefits because they require significant analysis of the data to drive the business changes (eg optimising asset management decisions, planning work routes, understanding inventory etc). Based on the BI toolset facilitating the last 20% of the $1.7m per year of savings, it will result in the 'savings capture' of $340k per year.

Table 4: Operating expenditure benefits and costs ($'000s real $2014/15)

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Cost Savings - Current data analysis - Reporting	0	0	(150)	(150)	(150)	**(450)**
IT Support Costs - Business Intelligence platform support - Business Intelligence application support	0	0	150	150	150	**450**
Net Opex costs	**0**	**0**	**0**	**0**	**0**	**0**
Cost Avoidance - Additional data analysis - Reporting data validation and correction	0	0	(150)	(150)	(150)	(450)
EAM Benefits - Supported EAM Benefits	0	0	(340)	(340)	(340)	(1,020)
TOTAL Benefits	**0**	**0**	**(790)**	**(790)**	**(790)**	**(1,470)**

As the final row of this table highlights by the end of the AAP the net benefit of this project (measured from an operating cost perspective) is expected to reach $1.47 million. The other important points to note from this table are that:

- the operational cost savings completely offset the additional IT support costs (including application support and maintenance); and
- the avoided costs have not been deducted from the IT support costs, because as noted above the costs associated with analysing and reporting the additional data required to support the EAM benefits realisation were not included in the EAM project and so do not form part of AGN's forecast for the upcoming period.

The dark shaded row in this table sets out the net opex requirement for the upcoming AAP, which is $0 because the operational cost savings completely offset the additional IT support costs. No additional allowance for opex is therefore required.

6 *Consistency with the National Gas Rules*

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the capital expenditure required to implement the Business Intelligence Toolset is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services and comply with regulatory obligations and requirements and is of a nature that a prudent service provider would incur.
- *Efficient* – The Business Intelligence Toolset project is cost effective and will enable AGN to improve operational efficiency and address the risks of non-compliance with relevant regulations and legislation, potential customer and business interruptions and corresponding

adverse financial and reputation impacts. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.

- *Consistent with accepted and good industry practice* – The Business Intelligence Toolset project will enable AGN to have rapid access to critical information when making decisions, which is in line with good industry practice. The project will also address the risks of non-compliance with relevant regulatory obligations through improved reporting and analytical capability.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The Business intelligence Project will enable more informed decision making throughout the business and assist AGN in delivering the lowest sustainable cost of delivering pipeline services.

The proposed capital expenditure is also consistent with rule 79(1)(b), because it is necessary to:

- Maintain and improve the safety of services (79(2)(c)(i)) – More extensive access to accurate information about assets and the ability to predict failures will result in a safer network..
- Maintain the integrity of services (79(2)(c)(ii) – The integrity of services will be preserved and improved through rapid and accurate access to financial and asset information.
- Comply with a regulatory obligation (79(2)(c)(iii)) – Access to more extensive and accurate asset information will decrease the cycle time required to meet regulatory reporting periods.

Attachment A: Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the Business Intelligence project is not carried out, while the bottom panel sets out the residual risks if the project is undertaken. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	Unlikely	Rare	Possible	Possible	Unlikely	Possible	Possible	Priority 3 51
	Consequence	Minor	Minor	Minor	Minor	Minor	Medium	Minor	
	Risk Level	Low	Negligible	Low	Low	Low	Moderate	Low	
		5	3	8	8	5	14	8	
Risk treated	Likelihood	Rare	Rare	Unlikely	Unlikely	Rare	Unlikely	Unlikely	Priority 3 36
	Consequence	Minor	Minor	Minor	Minor	Minor	Medium	Minor	
	Risk Level	Negligible	Negligible	Low	Low	Negligible	Moderate	Low	
		3	3	5	5	3	12	5	
Cumulative Risk Reduction for Option 1									15

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to AGNL.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose AGNL, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

AUSTRALIAN GAS NETWORKS

BUSINESS CASE SA62

SA SCADA System Upgrade

BUSINESS CASE – SA62

PROJECT REFERENCE	
Network	AGN– SA
Project No.	SA62
Project Name	SCADA and Historian Systems Upgrade
Budget Category	SIB Capex
Risk and Priority	High, Priority 2
Reference Docs	2015 South Australia Network IT Investment Plan
Confidentiality Claim	No
PROJECT APPROVAL	
Prepared By:	Mark Wielgosz, *Bus Systems & Reporting Manager, Network Support*
Reviewed By:	Robin Gray, *Manager Systems Operations, Networks SA*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 Project Overview

Rationale for Project	The Supervisory Control and Data Acquisition (SCADA) and Historian systems in South Australia are state based solutions and differ from the systems in place on AGN's other networks. The Historian system also has a limited life due to its capacity constraints meaning that it requires modifications and/or an upgrade prior to 2017. To bring these systems into line with AGN's other networks the following would need to occur: • the SA Networks ClearSCADA system would need to be upgraded to the National Networks ClearSCADA standard; and • the Historian System would need to be replaced with a new SA specific module on the Networks Interval Metering Data System application that runs on the existing National Enterprise Historian Platform. Bringing these systems into line with the national system will give rise to operational efficiencies and streamlining of processes and will also ensure the continued delivery of reliable SA Networks data to AEMO and other stakeholders. If the systems are not aligned, AGN, customers and staff/contractors will be exposed to a number of operational, customer and compliance risks.
Options Considered	AGN has considered two options: • Option 1: Do nothing, which would leave AGN, customers and staff/contractors exposed to a number of risks. • Option 2: Upgrade the SCADA and Historian Systems and bring them into line with AGN's other networks.
Option Selected	Option 2 has been selected because the do nothing option gives rise to a number of additional costs and inefficiencies that are avoided under Option 2. Option 2 will also: • allow customers to benefit from operating and maintenance efficiencies; • reduce operational, customer and compliance risks; and • enable AGN to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations.
Estimated Cost	The forecast capital expenditure for the SCADA and Historian Systems Upgrade project over the Access Arrangement Period (AAP) is $3.35 million (real $2014/15).
Consistency with the NGR	The capital expenditure associated with the SCADA and Historian Systems Upgrade complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because it is: • necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations (rules 79(2)(i), (ii) and (iii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the Maintain theme because its implementation will allow AGN to continue providing reliable and efficient supply of natural gas to

	our customers and to fulfil compliance obligations.

2 Background

AGN's IT systems are highly integrated, as illustrated in the IT architecture diagram below.

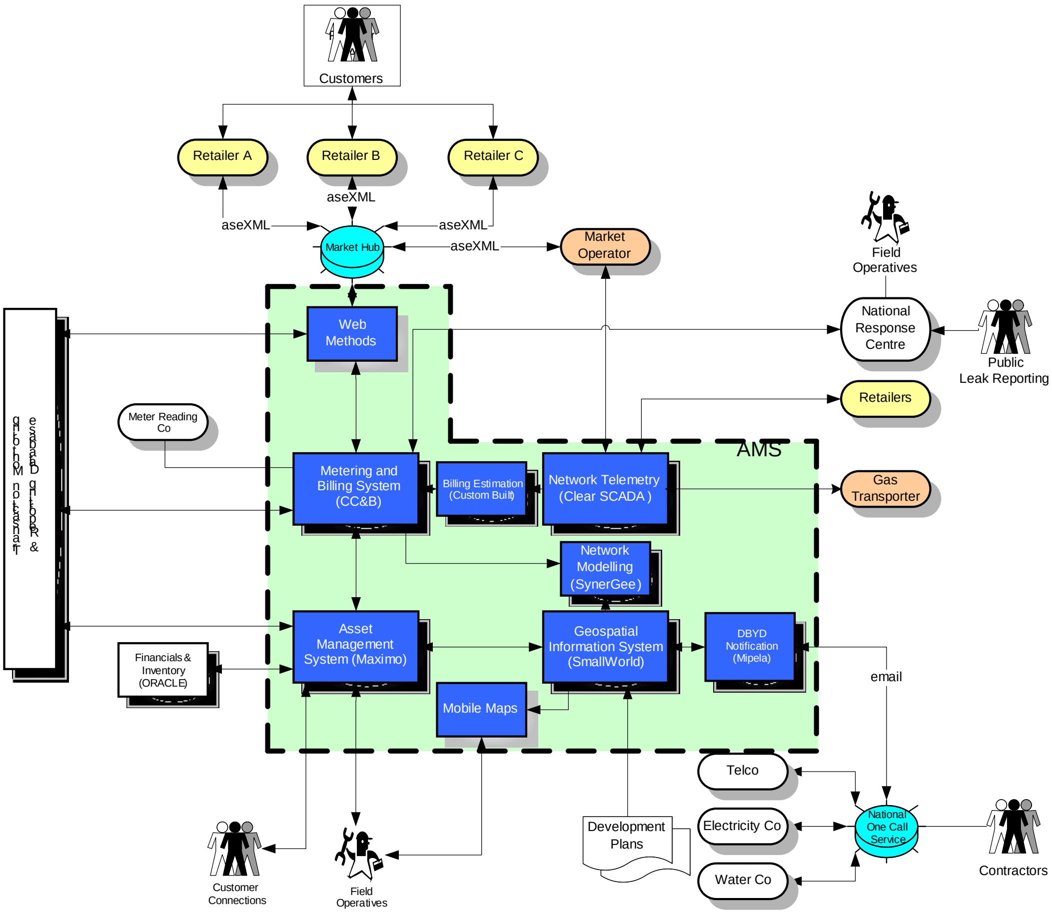


Figure 1: Networks IT architecture

These systems are used to provide the following business capabilities:

- Managing market transactions;
- Issue and control of field work;
- Monitoring and recording gas deliveries to customer sites;
- Emergency response;
- Monitoring network condition;
- Analysing network capacity;
- Recording the configuration and location of assets; and
- Reporting against compliance and contractual obligations.

Given their highly integrated nature, upgrades and improvements to these systems have been incorporated into a detailed Program of Work. The orderly delivery of this complete Program of Work is required to provide the full business benefits from the integrated suite of systems, including enhanced Asset Management capability, streamlined and scaled applications and processes and related risk mitigation.

The major IT system improvement projects that are to be carried out in the upcoming Access Arrangement Period (AAP) include:

- GIS Upgrade (SA58)
- Mobility Integration (SA59)
- Business Intelligence Toolset (SA60)
- SCADA and Historian System Upgrade (SA62)
- Remote Meter Reading (SA64)

This business case describes the requirement for the SCADA and Historian System Upgrade project. Separate business cases have been developed for the other projects listed above.

2.1 Project Scope

The SCADA and Historian systems currently in South Australia are state based solutions and differ from the systems operating on AGN networks in other parts of the country. The Historian system also has a limited life due to its capacity constraints meaning that it requires modifications and/or an upgrade prior to 2017. The link between the SCADA and Historian systems is based on text files being created and transferred into the Historian on a one hour cycle.

This data data link is based on an outdated technique, which commands system resources and a high level of configuration. Often files are missed leading to delays in actual data getting into the Historian system. This link was not updated in 2007 when the ClearSCADA system was configured. The links are based on old Citect SCADA point names, which are confusing in data analysis.

The overarching objective of this project is to upgrade the SCADA and Historian systems in South Australia and to bring them into line with the National system and link AGN's control and monitoring system with AGN’s Queensland and Victorian networks.

The high level scope for this project can be divided into the following two elements.

- upgrade the SA Networks ClearSCADA system to the National Networks ClearSCADA standard; and
- replace the SA Historian system (SA Telemetry FRC system) with a new SA specific module on the Networks Interval Metering Data System (NIMDS) application that runs on the existing National Enterprise Historian platform.

There are a number of assumptions that underlie the scope of each of these sub-projects, which are outlined below:

- **Upgrade of the SA Networks ClearSCADA -** The configuration and operation of the system will be identical to the National Networks ClearSCADA system. This means that, where appropriate, the alarms will be generated within the ClearSCADA system rather than within the site Remote Terminal Units (RTU). The configuration development will require modification to the National Networks ClearSCADA standards.

  This project builds on work undertaken in the current Access Arrangement period (AAP) to move the SA Networks ClearSCADA system onto the National Networks ClearSCADA platform. Upgrade of the SA Networks ClearSCADA system to the National Networks ClearSCADA standard forms part of this project, however, the project scope excludes any field work (e.g. replacement of hardware at metered sites) or communication work.

- **Replacement of Historian with a module on the Networks Interval Metering Data System -** The adoption of Networks Interval Metering Data System (NIMDS) business process requires modifications to the NIMDS processes. The systems and processes dealing with metering data and unaccounted for gas (UAFG) will continue to be used (i.e. this project will not attempt to replace any of that functionality). This means that data sources for these processes will not be impacted by this project and the validated SA interval metering data will continue to be obtained from the Metering, Billing and Accrual systems.

  The network, site and customer information will be manually populated and maintained in the new NIMDS (i.e. it will **not** be automatically populated from the Geographical Information System, Enterprise Asset Management or Metering and Billing systems). This is considered to be the most prudent solution. The networks security model will be nationalised for more efficient management of AGN's data. In particular there will be no state-based segregation of data – any person designated as able to view and/or edit networks billing data will be able to do so for all states.

  The project estimate includes alteration to the architecture surrounding the current SA NIMDS and to align with the national NIMDS platform. The SA specific NIMDS module will run on the national NIMDS platform with the Microsoft middleware product, BizTalk, the platform being used for handling delivery of output from the system to external parties.

On completion of this project, the upgraded SCADA and Historian systems are expected to deliver operational efficiencies and ensure the continued delivery of reliable SA Networks data to AEMO and other stakeholders. The specific benefits that are expected to be generated by this project are outlined in the table below.

Table 1: Benefits of the Upgrade

Change	Benefits
Upgrade of SCADA	Upgrading the SCADA System and bringing it into line with the National Networks ClearSCADA standard will give rise to the following operating and maintenance efficiencies: • Increased reliability of the SA Networks SCADA system. • Increased efficiency of obtaining accurate data from the SA Networks SCADA system. • Reduction in the manual effort required to correct SA Networks data before it goes to AEMO and other stakeholders. • the systems and processes required to operate and maintain the system can be standardised. • The ClearSCADA upgrade will create a direct link between the SCADA and Historian systems, which will streamline the system and decrease development time, while making the data available in real time.
Upgrade of Historian System	Upgrading the Historian System, will mean the following: • The cost of upgrading or modifying a non-standard system will be avoided (the current system has a capacity limit of 999 sites with approximately 760 already in use. Maximum capacity is likely to be reached in 2017 necessitating the upgrade of a non-standard system if the functionality is not migrated). • The new SA Networks ClearSCADA system will be integrated with the new NIMDS module. • A near fully automated solution will deliver SCADA data to AEMO and other stakeholders. • The risk of delivering unreliable SCADA data to AEMO and other stakeholders will be reduced.

2.2 Consistency of project with stakeholder expectations

As outlined in Chapter 3 of the AA Information, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to prudently and efficiently maintain current reliability and service levels. Consistent with the above insight, the SCADA and Historian System Upgrade project will enable AGN to continue to provide reliable and efficient supply of natural gas to customers as well as fulfilling our compliance obligations.

3 Risk Assessment

The risks of not upgrading the SCADA and Historian systems are as follows:

- The Historian System will not be able to report complete data sets to AEMO when the number of sites exceeds the capability of the existing SA Telemetry FRC system (compliance risk).
- Increased rate of failure as applications become unsupported by the product vendor, resulting in unplanned production outages and costly rectifications (operational and customer risk).
- The current standalone SA SCADA system does not support the business objectives – particularly regarding the national alignment and the delivery of initiatives to improve cost effectiveness.

AGN has carried out a risk assessment using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. This has entailed identifying existing and potential network operational risks (and residual risks) in terms of the consequences and the likelihood of the risk. Further detail on the risk assessment that has been carried out can be found in Attachment A.

In short, the untreated risk associated with the matters outlined above has been assessed as high from a compliance, operational and customer perspective, and accorded a Priority 2 rating.

4 Options

Two options have been identified to deal with the risks outlined above:

- Option 1 – Do nothing.
- Option 2 – Upgrade the SCADA and Historian Systems and bring into line with national system.

The costs and benefits associated with these two options are summarised in the table below.

Table 1: Costs and benefits of the options

Item	Option 1 Do Nothing	Option 2 SCADA and Historian System Upgrade
Costs/ Risks	Leaving the SCADA and Historian systems as non-standard systems will mean the following: • The systems will have to be monitored within SA and all updates and maintenance handled in isolation from the two other major AGN networks in Australia. This will result in the system becoming increasingly unreliable and result in significant costs in later years to align to the National Networks ClearSCADA standard. • Any future developments and enhancements of the ClearSCADA standards won't be able to be applied to the SA portion of the system. It will therefore become increasingly isolated from the rest of the system. • Retaining the current Historian system as a standalone system will cost more because it has a hard limit of available sites (999), which will be reached in this AAP and will therefore have to be upgraded or modified to meet demand. • Not taking the opportunity to standardise both systems will perpetuate the continuation of SA having different processes nationally, which inherently is less flexible. • AGN, customers and staff/contractors will continue to be exposed to the operational, customer and compliance risks outlined in Section 3 and Attachment A, including the risk of not meeting AGN's obligations under the Retail Market Procedures and Market expectations regarding the provision of accurate, timely information to stakeholders.	$3.345 million capex (real $2014/15)
Benefits	No upfront capital costs for the SCADA system but costs will be incurred upgrading or modifying the Historian system.	Upgrading the systems will: • Give rise to maintenance and operating efficiencies (ie, from the alignment with the National Networks ClearSCADA standard). • Avoid the increased costs of upgrading the non-standard Historian system. • Provide for a nationally consistent user interface and method of operation. • Allow resources to be shared nationally (SCADA resources are scarce). Confining them to one state limits flexibility and results in increased costs. Standardising the ClearScada configuration facilitates the use of resources across states when required. • Provide a near fully automated solution to deliver SCADA data to AEMO and other stakeholders and reduces risk of delivering unreliable data.

Item	Option 1 Do Nothing	Option 2 SCADA and Historian System Upgrade
		• Reduce the operational, customer and compliance risks outlined in section 3 from high to moderate (see Attachment A).

As this table highlights, Option1, do nothing gives rise to additional costs and inefficiencies and will leave AGN, customers and staff/contractors to operational, customer and compliance risks (see section 3 and Attachment A). Option 2, on the other hand, involves an upfront capital cost but has a number of significant benefits including:

- allowing customers to benefit from maintenance and operating efficiencies;
- reducing the operational, customer and compliance risks outlined above; and
- enabling AGN to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations.

Option 2 has therefore been selected.

Finally, it is worth noting that during the option analysis, AGN developed costing around just re-engineering the existing SA Historian system to expand its capacity, which identified cost in the order of $1 million. This estimate did not include project costs, or the cost of upgrading the hardware, licensing, moving to high-availability, or other factors considered in a proper scoping study. The cost associated with amending the code (circa $1m) was sufficient for AGN to conclude that it would not be prudent to pursue this option any further.

5 Forecast Cost for the Upcoming AAP

The table below provide a summary of the capital expenditure that is forecast to be incurred in the next AAP if the SCADA and Historian Systems Upgrade Project is implemented. The forecast contained in this table having regard to the costs that AGN is currently incurring in the upgrade of its Queensland Network's SCADA system.

Table 2: Capital expenditure ($'000s real $2014/15 – excluding overheads)

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
SA ClearSCADA	982	640				**1,622**
SA NIMDS	978	534				**1,512**
Hardware and Licenses	211					
Total	**2,171**	**1,174**				**3,345**

The table below provides a further breakdown of the forecast expenditure by stage.

Table 2: Capital expenditure breakdown by stage

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	SA SCADA System Upgrade	
Project Complexity:	Complex	
Project Type:	Major Change	
Estimations Summary		
Total Project (end to end)	Effort (Days)	Total Cost
End to End Total	1911	$ 3,344,604.00
Estimations by Project Stage		
		Stage Cost
Develop Stage Total	255	$ 325,160.00
Plan Stage Total	500	$ 836,660.00
Deliver Stage Total	1056	$ 2,069,584.00
Close Stage Total	100	$ 124,520.00

6 *Consistency with the National Gas Rules*

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the capital expenditure required to implement the SCADA and Historian Systems Upgrade Project is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services and comply with regulatory obligations and requirements and is of a nature that a prudent service provider would incur.
- *Efficient* – The project is cost effective and will enable AGN to improve operational efficiency and address the risks of non-compliance and other risks outlined above. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – The upgrade will align the regional systems with the national systems and ensure the Historian system is sized to meet the expected requirements. It is good practice to maintain these critical systems and ensure they are fit for purpose.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The alignment of the systems to a national standard to allow easier maintenance, growth in requirements and efficiencies from national processes will contribute to the achievement of the lowest sustainable cost of delivering pipeline services over the medium to longer term.

The proposed capital expenditure is also consistent with rule 79(1)(b), because it is necessary to:

- Maintain and improve the safety of services (79(2)(c)(i)) – The safety of services could be adversely affected if the SCADA system fails. The upgrade project mitigates this risk.
- Maintain the integrity of services (79(2)(c)(ii) – The integrity of the services will be adversely affected if the SCADA system is not available. The upgrade project mitigates against this risk.
- Comply with a regulatory obligation (79(2)(c)(iii)) – Regulatory obligations will be breached if the SCADA systems are not available. The upgrade project mitigates against this risk.

Attachment A: Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the SCADA and Historian Systems Upgrade project is not carried out, while the bottom panel sets out the residual risks if the project is undertaken. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	*Possible*	*Possible*	*Likely*	*Unlikely*	*Possible*	*Possible*	*Occasional*	
	Consequence	*Insignificant*	*Insignificant*	*Medium*	*Major*	*Medium*	*Major*	*Medium*	
	Risk Level	*Negligible*	*Negligible*	*High*	*High*	*Moderate*	*High*	*Moderate*	*Priority 2*
		4	*4*	*23*	*21*	*14*	*25*	*18*	***109***
Risk Treated	**Likelihood**	*Possible*	*Possible*	*Possible*	*Rare*	*Unlikely*	*Unlikely*	*Occasional*	
	Consequence	*Insignificant*	*Insignificant*	*Medium*	*Major*	*Medium*	*Major*	*Medium*	
		Negligible	*Negligible*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	***Priority 3***
		4	*4*	*14*	*16*	*12*	*18*	*18*	***78***
	Cumulative Risk Reduction for Option 1								

Priority		**Priority Description**
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

APA Group

Asset Strategy and Planning

Australian Gas Networks

AUSTRALIAN GAS NETWORKS

BUSINESS CASE SA64

Remote Meter Read Project

BUSINESS CASE – SA64

PROJECT REFERENCE	
Network	AGN– SA
Project No.	SA64
Project Name	Remote Meter (AMR) Project
Budget Category	Capex/Opex
Risk and Priority	Moderate, Priority 2
Reference Docs	2015 South Australia Network IT Investment Plan
Confidentiality Claim	Yes
PROJECT APPROVAL	
Prepared By:	Errol Murray, *Projects and Revenue Assurance Manager, Shared Services*
Reviewed By:	Ken Hedley, *General Manager, Shared Services*
Approved By:	Ken Hedley, *General Manager, Shared Services*

1 Project Overview

Rationale for Project	AGN's ability to comply with the requirement in the Retail Market Procedures that an actual meter read be carried out at least once a year across all meters is becoming increasingly difficult because of the growing numbers of inaccessible sites. To address this issue, AGN is currently considering options to remotely read gas meters and would like to carry out a trial in both new and existing areas over the next Access Arrangement Period (AAP). The results of this trial will provide AGN with a better understanding of whether the benefits of the remote read technology will outweigh the costs and therefore enable it to make a more robust decision about whether a fuller deployment of this technology would be in the long-term interests of consumers. The benefits of installing this type of technology include: eliminating the high number of estimated meter reads, improving customer service and satisfaction (i.e. by reducing billing errors), and achieving other operational efficiencies.
Options Considered	AGN considered three options: • Option 1: Do nothing. • Option 2: Install Automated Meter Reading (AMR) on gas meters – AMR is a drive-by electronic meter read that has been adopted in a number of international jurisdictions. • Option 3: Install smart meters.
Option Selected	Option 2 has been selected for the trial because it is much cheaper than the smart meter option and many of the benefits offered by smart meters are less relevant in a gas context. This option is also preferred over Option 1 because it will enable AGN to deal with some immediate customer/compliance issues arising in existing hard to access sites.
Estimated Cost	The forecast capital expenditure for the Remote Meter Read Trial is $2.505 million (real $2014/15), while the forecast operating expenditure over the AAP is $0.53 million.
Consistency with the NGR	The capital expenditure component of the Remote Meter Read trial complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because it is: • necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations (rules 79(2)(i), (ii) and (iii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services. The operating expenditure component of the Remote Meter Read Trial is also such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services, consistent with rule 91(1).
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This trial is consistent with the Improve and Efficient themes because its implementation will enable AGN to consider whether meter reading services can be improved and if the benefits of doing so will outweigh the costs.

2 Background

AGN's IT systems are highly integrated, as illustrated in the IT architecture diagram below.

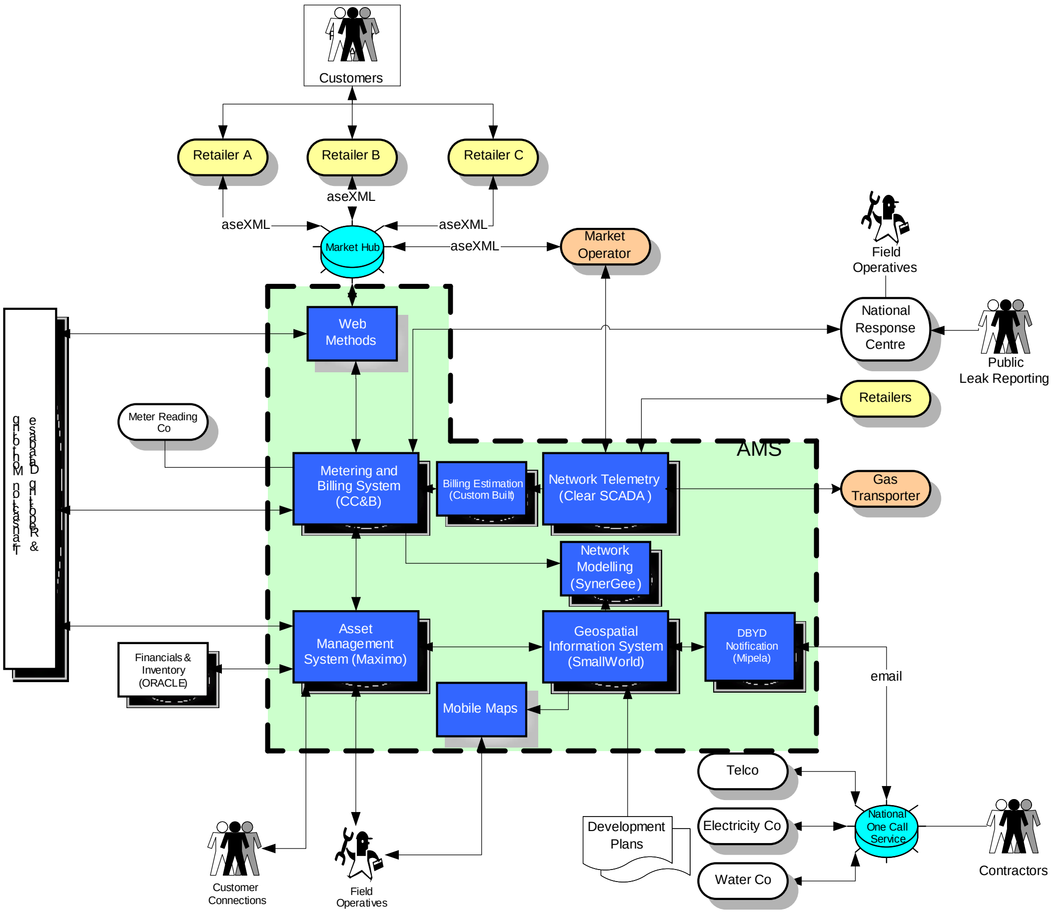


Figure 1: Networks IT architecture

These systems are used to provide the following business capabilities:

- Managing market transactions;
- Issue and control of field work;
- Monitoring and recording gas deliveries to customer sites;
- Emergency response;
- Monitoring network condition;
- Analysing network capacity;
- Recording the configuration and location of assets; and
- Reporting against compliance and contractual obligations.

Given their highly integrated nature, upgrades and improvements to these systems have been incorporated into a detailed Program of Work. The orderly delivery of this complete Program of

Work is required to provide the full business benefits from the integrated suite of systems, including enhanced Asset Management capability, streamlined and scaled applications and processes and related risk mitigation.

The major IT system improvement projects that are to be carried out in the upcoming Access Arrangement Period (AAP) include:

- GIS Upgrade (SA58)
- Mobility Integration (SA59)
- Business Intelligence Toolset (SA60)
- SCADA and Historian System Upgrade (SA62)
- Remote Meter Reading (SA64)

This business case describes the requirement for the Remote Meter Reading project. Separate business cases have been developed for the other projects listed above.

2.1 Current situation

AGN has approximately 425,000 basic metered customers in its South Australian network. These customers are visited four times a year by a meter reader to obtain a physical meter read in accordance with both the Retail Market Procedures (South Australia) (RMP), and AGN's Access Arrangement Terms and Conditions. Under the RMP AGN is further required to obtain an actual meter read at least once a year.

The RMP dictates that by 31 August each year AGN must create an annual meter reading schedule for the next calendar year, which sets out the date or dates in the 12 month period on which the network operator proposes to read the meters whose MIRNs are assigned to that reading day number. This schedule is provided to the retailers to enable the retailers to incorporate the details into their systems and also to advise their customers of their next scheduled read date. This information is included on the customer's current invoice to enable them to ensure AGN has access to read their meter on or around the next scheduled read date.

While AGN meets its obligation to attend basic metered sites at least four times annually in South Australia, in many instances AGN's meter reader is unable to obtain an actual meter read due to inaccessibility of the site.

The RMP allows AGN to disconnect the customer in the street (i.e. at the service) if the customer does not enable AGN to meet its annual obligation. AGN does not consider this to be a prudent approach in its endeavours to further the development of gas in the state of South Australia, or from a customer service perspective as the customer would be obligated to pay a reconnection cost in excess of several hundred dollars to have gas reconnected.

In addition to the existing access issues there are a number of contributory factors that make the assessment of alternative mechanisms for meter readings important. These include:

- increasing no access rates;
- meter reader safety;

- customer transfers;
- poor location of meters with higher density urban living;
- increasing customer complaints relating to the absence of meter readings;
- increasing work effort to cancel and reissue bills with estimated reading;
- retailer notification and workload in arranging appointments;
- complexity of customer keys management; and
- necessity of an annual project to attend no access sites.

Further detail on these issues is provided in Attachment B.

2.2 Project Scope

To address the operational challenges outlined above, AGN is considering installing Automated Meter Reading (AMR) on gas meters. The initial solution selected is essentially a drive by electronic meter read, which has been adopted in a number of international jurisdictions (see Attachment D).

To assess the feasibility of this solution AGN proposes to undertake a trial in both new and existing areas over the next Access Arrangement Period (AAP), to get a better understanding of how AMR can:

- eliminate the high number of estimated reads, the majority of which result from difficult-to-access meters in order to meet its regulatory obligation of obtaining an actual meter read at least annually;
- improve customer service and satisfaction by delivering accurate billing to its customer base in a timely manner, which will, in turn reduce billing errors, high-bill complaints, and rework involved with processing billing adjustments; and
- prepare for the future by building a meter reading infrastructure that would enable AGN to cost-effectively implement more advanced data collection technologies as its strategic objectives and market demands dictate.

The results of the trial program will provide AGN with a better understanding of the costs and benefits of the remote read technology (including time frames for drive by completion of reads per day / route, volumes of estimated reads, the volumes of adjusted meter reads and complaint/ombudsman referred matter volumes) and mean it will be in a better position to make a robust decision about whether a fuller deployment of this technology should be carried out.

The trial will target two distinct meter reading challenges to enable the technology to be implemented and be tested in a low risk and low cost environment. These include:

1. Customer sites that historically have very poor access, mainly due to customer security/privacy choices/concerns. AGN has identified this increasing trend as one that needs to be addressed and is implementing this project as a trial solution.

2. A new subdivision that is in early stages of development (such as Buckland Park or Tanunda) where all connections can be completed as remote access to determine the efficiency and effectiveness of this approach. Once successful this can be considered for further expansion for the South Australian Gas Distribution Network.

Apart from enabling AGN to assess whether a wider scale rollout of this technology should occur, this project will:

- enable AGN to meet its regulatory obligation to obtain an actual meter read every calendar year for those meters that have previously proven difficult to access;
- improve meter read accuracy for hard to access sites, thereby increasing customer service levels and reducing the work that would otherwise be involved in dealing with customer complaints and adjusting bills; and
- reduce HSE risks – slips, trips, falls, dog bites, wasp/bee stings, aggressive customers etc. – by eliminating the need to physically enter properties to obtain meter reads.

2.3 Consistency of project with stakeholder expectations

As outlined in Chapter 3 of the AA Information, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they want AGN to explore ways in which services can be improved and that they want AGN to promote efficient price outcomes for consumers. Consistent with the above insights, the Remote Meter Reading trial project will enable AGN to consider whether meter reading services can be improved and if the benefits of doing so will outweigh the costs.

3 Risk Assessment

AGN has carried out a risk assessment using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. This has entailed identifying existing and potential network operational risks (and residual risks) in terms of the consequences and the likelihood of the risk. Further detail on the risk assessment that has been carried out can be found in Attachment A.

In short, the untreated risk associated with the matters outlined above has been assessed as moderate from a compliance, customer and reputational perspective, and accorded a Priority 2 rating. The key factors driving the risk rating are:

- AGN's regulatory obligation to meet the annual meter reading requirement in the RMP; and
- the inaccuracy of meter reads at hard to access sites, which reduces customer service levels and gives rise to additional work.

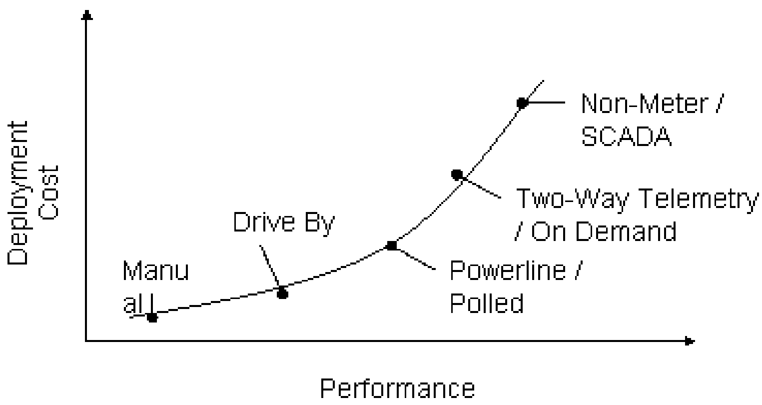
4 Options

The three options that AGN has considered to address the issues outlined above are:

- Option 1: Continue with current manual meter reading solution for all customers – Under this option the meters of all new and existing residential customers will continue to be manually read, which means that the issues outlined above for hard to access customers will persist and become more significant over time as meters become increasingly hard to access (see Attachment B for more information on why this is the case).

- Option 2: Carry out a trial of the AMR solution ('Drive By') - This solution has been employed internationally and, as noted in Attachment D, has been successful in improving meter reading efficiency, reducing estimated reads, increasing billing accuracy and reducing billing complaints and adjustments. Under this option AMR would be trialed at 4,000 hard to access sites and 1,746 new sub-division connections.
- Option 3: Carry out a trial of smart meters (Powerline/polled and two-way telemetry) – This solution has been employed in Victoria and while there are many benefits associated with smart meters, the deployment costs can be significant as highlighted by the Victorian experience.

In the early 2000s Eric Cody of Plexus Research provided an installation cost to performance roadmap for these alternative options. An adaptation of this roadmap is set out in the figure below.



As this figure reveals, the 'Drive By' (ie, AMR), Powerline/Polled and Two-way telemetry (ie, smart meter) options represent a step forward from manual read meters in terms of performance, but there can be a significant difference in the cost of deploying these options, with the Drive By option being far cheaper than the smart meter options. The other point to bear in mind with this figure is that gas does not have the same drivers as electricity in terms of trying to reduce or manage demand, so many of the performance related benefits that smart meters offer will be less relevant in a gas context. AGN has therefore decided to trial the less costly AMR ('Drive By') solution.

A trial of this technology in the South Australia network will enable AGN to deal with some immediate customer/regulatory issues arising in existing hard to access sites and to also test the application of the technology more broadly in South Australia, so that AGN can make an informed and robust decision about whether a fuller deployment of this technology will be in the long-term interests of consumers.

5 *Forecast Cost for the Upcoming AAP*

The table below provide a summary of the capital and operating expenditure that is forecast to be incurred in the next AAP under the Remote Meter Read Trial. Further detail on how the capital and operating expenditure components of this forecast have been developed is provided below.

Table 2: Capital and operating expenditure ($'000s $2014/15 – excluding overheads)

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	**Total**
Capital Expenditure (Remote meter read)	1,504	632	111	123	136	**2,505**
Net Operating Expenditure (Gross Operating Expenditure less cost savings)	85	123	99	107	117	**530**

5.1 *Capex*

The capex forecast include the following components:

1. **Direct Hardware costs** – The following hardware will be required to carry out the trial: remote meter devices, new handhelds, mobile AMR receivers for data collection and collation. The estimated cost of this hardware has been based on a quote that was obtained from Landis & Gyr. If this project is approved by the AER, AGN will carry out a competitive tender to ensure that the service can be delivered in the most cost effective manner.
2. **External IT contractor costs** – External IT contractors will be required to design and implement the remote meter reading applications into Service Stream and AGN's metering and billing systems. These costs are based on current IT contractor rates, which is $2,000 per day.

The costs of each of these elements are set out in the table below. A more detailed breakdown is provided in Attachment C. It is also worth noting here that AMR is assumed to be installed at 4,000 hard to access sites in the first two years and the 1,746 new sub division connections over the five year period.

Table 2: Capital expenditure ($'000s $2014/15 – excluding overheads)

Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Hard to Access Sites	496	484	-	-	-	**980**
New Sub-division connections	38	48	61	73	86	**305**
IT System Costs	970	100	50	50	50	**1,220**
Total	**1,504**	**632**	**111**	**123**	**136**	**2,505**

5.2 Opex

The opex forecast consists of the following components:

- Internal IT support and Hosting Data costs, which are based on a quote from Landis and Gyr and an estimated requirement of approximately 0.4 FTE per annum; and
- Meter Reading Costs – expressed as a saving once the project is implemented.

In relation to the latter of these components, it is worth noting that it is unlikely that there will be significant savings or operational efficiencies afforded by the existing hard to read customers because they are spread throughout AGN's distribution network rather than located in a specific cluster where a vehicle drive by approach could significantly reduce the timeframe for undertaking a large volume of reads. AGN considers if successful there will be approximately $30k savings annually from the cessation of its annual meter visit program. While the cost savings associated with hard to access meters are relatively low, greater efficiencies are expected to be achieved when there are a greater number of meters clustered in one location. The scale of these benefits is unknown at this time but will be tested during the trial of AMR in a new subdivision.

The table below sets out each of these components of the opex forecast and the net opex requirement for the next AAP, which ranges from $85,000-$117,000 p.a. (or $0.53 million over the full AAP).

Table 3: Operating expenditure ($'000s real $2014/15 – excluding overheads)

Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Web IMR Annual support	35	73	79	87	97	**370**
IT Support	50	50	50	50	50	**250**
Total opex	**85**	**123**	**129**	**137**	**147**	**620**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

5.3 Justification for non-base year opex – capex related opex

The Remote Meter Read trial will give rise to a $0.53 million increase in operating expenditure over the AAP. This expenditure does not currently form part of the base year opex, nor is it reflected in the rate of change that AGN has used when applying the base step trend approach. A $0.53 million allowance for non-base year opex is therefore required to give effect to the decision to carry out the trial and can therefore be viewed as capex related opex.

As noted previously, the decision to carry out the Remote Meter Read trial is being driven by the need to:

- comply with existing regulatory obligations under the RMP (consistent with rule 79(1)(b) of the National Gas Rules), which is becoming increasingly difficult because of the growing number of hard to access sites; and

- consider whether the longer term interests of consumers (with respect to price and quality) could be improved by moving to remote meter reading (ie, because it would improve the efficient operation of the pipeline).

The first of these factors is consistent with rule 79(1)(b) of the National Gas Rules, while the second is consistent with the National Gas Objective. The proposed step change is also consistent with the opex criteria (see section 7) and section 24(2) of the National Gas Law, which states that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs that it incurs in providing reference services and complying with regulatory obligations. The $0.53 million should therefore form part of AGN's opex forecast.

6 Consistency with the National Gas Rules

Consistent with the requirements set out in rules 79(1)(a) and 91 of the National Gas Rules, AGN considers that the additional expenditure that it is seeking in order to implement this trial is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services and comply with regulatory obligations and requirements and is of a nature that a prudent service provider would incur.
- *Efficient* – The project will enable AGN to improve operational efficiency and address the risks of non-compliance with the RMP. The option selected is also a much lower cost option than a full smart meter solution. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – It is good industry practice to consider options for moving away from manual processes to solutions that increases reliability and accuracy where the benefits are expected to outweigh the cost. This relatively low cost trial will enable AGN to assess whether the benefits of the remote reading option will outweigh the cost and to make a decision about whether to roll more of these meters out.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The trial is required to assess the future options for achieving the lowest sustainable cost of meter reading services in addition to solving current issues with access to difficult sites and is therefore consistent with the objective of achieving the lowest sustainable cost of delivering pipeline services.

The proposed capital expenditure is also consistent with 79(1)(b), because it is necessary to:

- Maintain and improve the safety of services (79(2)(c)(i)) – The safety of meter reading could be improved if difficult to access premises were remotely read.
- Maintain the integrity of services (79(2)(c)(ii) – The increased use of actual rather than estimated reads will improve the accuracy of the data and therefore enhance the integrity of services.
- Comply with a regulatory obligation (79(2)(c)(iii)) – The use of remotely read meters will facilitate achievement of the obligation in the RMP that an actual meter read be carried out each year.

Attachment A: Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming the Remote Meter Reading trial is not carried out, while the bottom panel sets out the residual risks if the project is undertaken. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environmental	Operational	Customers	Reputational	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	**Likelihood**	Occasional	Rare	Frequent	Likely	Possible	Frequent	Likely	
	Consequence	Minor	Insignificant	Insignificant	Insignificant	Insignificant	Minor	Insignificant	
	Risk Level	Low	Negligible	Low	Moderate	Moderate	Moderate	Low	
		10	1	11	18	14	19	9	**82**

		Health & Safety	Environmental	Operational	Customers	Reputational	Compliance	Financial	Total Score of Risk Levels
Risk after project	**Likelihood**	Rare	Rare	Rare	Possible	Unlikely	Unlikely	Unlikely	
	Consequence	Minor	Insignificant	Insignificant	Insignificant	Insignificant	Minor	Insignificant	
	Risk Level	Negligible	Negligible	Negligible	Negligible	Negligible	Low	Negligible	
		3	1	1	4	2	5	2	**18**

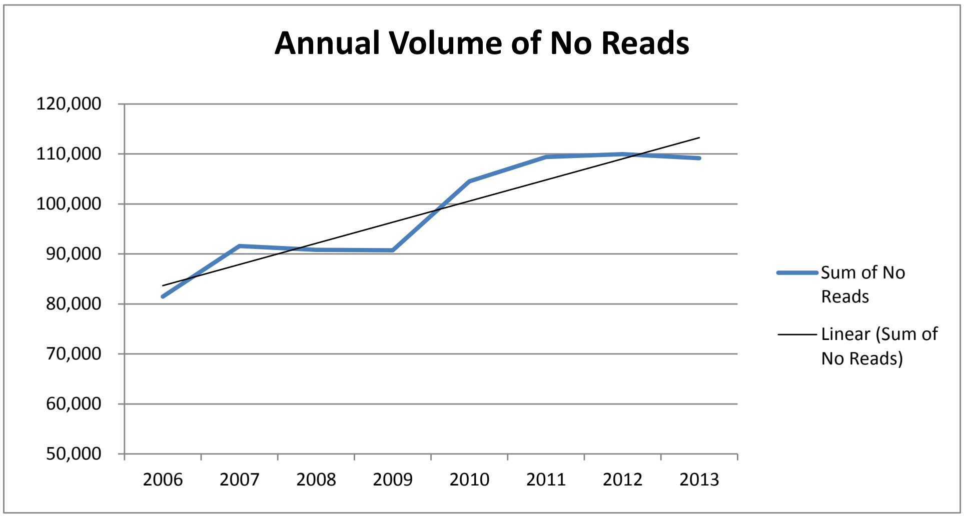
Cumulative Risk Reduction	**64**

Priority		**Priority Description**
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

Attachment B– Meter Reading Issues Impacting AGN

Access Issues – statistical history

The trend of 'no access' properties is increasing and is reaching levels of 8% and above on some read cycle days. With increasing inner city / higher density residential living, an ageing population and changing demographics (i.e. more families where both partners work), access to read meters is becoming more difficult. AGN considers this trend is likely to is increase with customers installing fences, additional locks and security devices, which prohibit meter readers from gaining access. The following graph highlights the increased volume of "no access" meter read visits from 80,000 pa in 2006 to in excess of 109,000 in 2013.



AGN has identified that in recent years customers have become more security conscious resulting in reduced access to properties, thus putting pressure on AGN's ability to meet their market obligation with many meters placed behind customer fences.

Globally, there is increasing evidence that the advent of the computerised era has contributed to access issues with the rise of Home Automation systems projected to rise 13 fold in the US from 1.5 million units in 2011 to 20 million units by 2017.[1] Many of these systems incorporate property security access components, which will further add to the difficulty in obtaining actual reads. This reinforces AGN's anecdotal evidence that physical access to read meters needs to be considered now to cater for the future.

[1] Telcos, Utilities, Cable Companies, and Security Providers Look to $12 Billion Home Automation Systems Market for Growth, May 31, 2012 http://www.fiercetelecom.com/press-releases/telcos-utilities-cable-companies-and-security-providers-look-12-billion-hom

Meter Reader Safety

AGN as a prudent operator place a significant emphasis on employee and contractor safety, and continually reviews “injury” and “near miss” instances with its meter reader contractor with the aim of reaching a “zero harm” environment.

Over the years AGN’s contractor has introduced several training programs including ‘bark busters’ and ‘aggressive customer management’ training to ensure meter readers are skilled in identifying potentially hazardous or unsafe situations in order to avoid injury. AGN as a prudent operator has advised the meter read contractor that employee safety will always override the RMP requirement to obtain a meter read, and if a meter reader has any concern that obtaining a meter read will place their safety in jeopardy they should not attempt to enter the premises.

Customer Transfers

The SA RMP requires an actual meter read for the customer to be able to transfer from their current retailer to a new retailer. The majority of transfer requests are for the transfer to occur on the customers next scheduled meter read. In instances where access cannot be obtained and an ‘estimated meter read’ is generated the customer transfer request is cancelled. This leads to delays in a customer’s transfer request, and potentially additional costs if they request a special meter read to enable the transfer to occur more quickly than waiting for the next scheduled read.

There can also be communication breakdowns with retailers and customers where a special transfer meter read has been requested but the customer has not made the meter accessible and access cannot be gained to obtain an actual meter read.

Poor Location of Meters

Higher density urban living and business premises can be problematic for meter readers to access the meter to obtain a read as meters can be located in basements, behind locked gates, hard to access positions and even a number of feet above the ground.

Complaints

AGN not being able to obtain access to undertake a meter read often results in complaints to AGN, the customer’s retailer and / or direct to the Ombudsman. This diverts resources away from value add activities to investigating allegations as to why the meter reader could not gain access to the customers site on the day in question, and / or damage resulting from the meter readers visit to the customer’s premises.

Increased Work Effort

There is often effort required both by AGN (as distributor) and the individual retailers to cancel and reissue estimated meter read bills, upon subsequent gaining of access to the customer’s premises.

Retailer notification

AGN notifies retailers of every instance where an actual meter read has not been able to be completed when the read information file is sent to the retailer, with information advising of the reason the read was not obtained i.e. locked gate, dog present etc. Retailers have confirmed they receive this information and notify customers on their bill that an actual read was unable to be obtained due to access issues. AGL advised their process is as follows:[2]

"Where the reason code is customer related (for example "locked gate" or "savage dog") we do the following:

- 1st invoice with an estimate, a message is printed on the invoice advising the customer that we could not access the meter, and they need to provide access in future.
- 2nd consecutive invoice with an estimate (and all subsequent consecutive invoices with an estimate), the message is printed on the invoice, and a letter is sent with the invoice advising the customer needs to provide access."

Two other national retailers have confirmed they also use information received from AGN to notify the customer of the reason for the estimated account, and where there are consecutive estimated reads notify the customer to arrange access for the next scheduled read.

Even with this involvement from the retailers 'no access' reads are steadily increasing each year as previously highlighted in Graph 1, and are only likely to further increase with increased customer security expectations on the rise.

Customer Keys management – Control, Risk, Management, Cost Security

To further mitigate 'no access' issues AGN has long had a process to manage customer keys for the security conscious customers. AGN currently manages keys for approximately 1% of customers in the South Australian jurisdiction (i.e. approx. 4,000 keys).

This process does, however, come at a cost to ensure security of keys, and coordination of keys to meter readers when they are undertaking the read routes for customers on that day. Keys are signed out to meter readers, signed back in when returned and reconciled to ensure there is a match to the keys issued and those returned. Details of customer keys are also recorded in AGN's metering and billing systems so meter reader messaging can include these details.

Annual Project to attend No Access sites

In recent years, AGN has instituted an annual project to visit South Australia "No Access" sites each year in a further attempt to meet its regulatory obligation of obtaining an annual read. In December of each calendar year a list of sites where an actual read has not been obtained is generated and targeted for a site visit. These sites are visited during the school holiday period where there is an increased likelihood somebody may be at home to enable site access for the meter reader to complete the read.

[2] Email from AGL 8th July 2014, available on request.

Regulatory

The RMP allow AGN to disconnect the customer in the street (i.e. at the service) if the customer does not enable AGN to meet its annual meter reading requirement obligation. AGN however, considers this to be an imprudent approach to meeting its regulatory obligation and is contrary to AGN's endeavours to further the development of gas in the state of South Australia. In particular, AGN considers this approach would damage its market reputation from a customer service perspective as the customer would be obligated to pay a reconnection cost in excess of several hundred dollars to have gas reconnected, and would potentially shift to an alternate energy fuel.

Attachment C – Detailed Cost Breakdown

South Australia AA AMR Costs - Capex

Volumes connected by year						
	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Hard to Access Sites	2000	2000	0	0	0	4000
New Sub-division connections	101	226	349	473	597	1746
Total	**2101**	**2226**	**349**	**473**	**597**	**5746**

$k (2014/15 – excluding overheads)						
Hard to Access Sites	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Coordination of Access, communications etc	100	100	-	-	-	200
Retro-fitting new / compliant meters	80	80	-	-	-	160
Remote Read device cost	154	154	-	-	-	307
Cost to fit Remote device	150	150	-	-	-	300
Handsets	13					13
Total	**496**	**484**	**-**	**-**	**-**	**980**

$k (2014/15 – excluding overheads)						
New Sub-division connections	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Coordination of Access, communications etc	25	25	25	25	25	125
Remote Read device cost	8	17	27	36	46	134
Cost to fit Remote device	3	6	9	12	15	44
Handsets	3					3
Total	**38**	**48**	**61**	**73**	**86**	**305**

$k (2014/15 – excluding overheads)						
IT System Costs	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Project Management	150					150
Requirements documentation	100					100
Design	160					160
Testing	80					80
Cross system testing (SS -MnB)	80					80
Implementation	200					200
Training and ongoing Support	200	100	50	50	50	450
Total	**970**	**100**	**50**	**50**	**50**	**1,220**

[redacted]

Attachment D: International Experience with AMR

Example 1 - St. Crois Valley Natural Gas

St. Crois Valley Natural Gas is a small rural utility in Wisconsin, US. Back in 2000, up to four meter readers armed with paper route books and pencils would take to the field to manually read and record 5,500 meters. This task took 20 eight-hour days to get the five billing cycles read each month.

St Croix began implementing an AMR solution and by May 2001, was using a vehicle-mounted DataPac computer that allowed the meters to be read as the vehicle drove past the gas meters, collecting reads from more than 99.8% of its encoder receiver transmitter equipped meters.

By mid-2005, 99.7% of St Croix's 6,700 gas meter base was equipped with AMR technology. Don Piepgras, president of the privately owned St. Crois Valley Natural Gas reported "We've gained efficiency in the office because we don't have all that manual data entry, and we rarely get re-read requests because the system is so accurate".

Example 2 - Missouri Gas Energy

Missouri Gas Energy required an AMR solution that could be installed quickly to deliver accurate and timely monthly consumption reads for 497,000 gas meters (including some 30,000 indoor gas meters) in the most efficient manner possible. MGE also wanted a solution that would enable the utility to centralize and streamline its meter reading operations. In addition, MGE required a system that could efficiently perform beginning and end-of-service or "succession reads" each day, as well as provide tamper reporting capability to detect and discourage theft of services.

Missouri Gas Energy determined Mobile AMR technology provided the most cost effective solution. Mobile AMR technology delivers operational benefits by dramatically increasing meter reading efficiency and improving customer service through the elimination of estimated reads and the timely delivery of accurate consumption data for billing.

First on the list of Missouri Gas Energy's objectives in deploying a territory-wide AMR system was to provide improved customer service through the elimination of estimated reads. To achieve this objective as quickly as possible, MGE and Itron used a "turnkey" installation strategy in which Itron employed third-party contractors to install the system on a very aggressive schedule. Meter module installation began in the spring of 1997, and within 12 months, some 470,000 meter modules had been installed. As the meter modules were installed, MGE immediately began using its Itron DataCommand Units to collect the reads and deliver the data to billing.

With a 497,000-end-point AMR system installed and functioning, Missouri Gas Energy reported meter reading efficiency had increased dramatically. Prior to installation, MGE relied on a staff of 72 full-time meter readers, compared to six full-time meter readers today. MGE has also reduced estimated reads — a continual source of customer frustration for utilities — from 8% to .04%. In turn, the reduction in estimated reads has increased overall billing accuracy and reduced the number of high-bill complaints, billing adjustments and call centre traffic. In addition, the AMR system enabled MGE to consolidate its host processing operations from four locations to one location, to further enhance operational efficiency.

APA Group

Asset Strategy and Planning

Australian Gas Networks

AUSTRALIAN GAS NETWORKS

BUSINESS CASE SA65

Industry Change Projects

PROJECT REFERENCE	
Network	AGN – SA
Project No.	SA65
Project Name	Shared Services – Industry Change Projects
Budget Category	Both
Risk Rating and Priority	Moderate, Priority 3
Reference Docs	AEMO, Guideline – Change management process for the Gas Retail Markets, 11 December 2012, Document Ref: Project-80-24, Appendix 3 and p. 4. Additional reference materials are contained in this document as appendices.
Confidentiality Claim	No
PROJECT APPROVAL	
Prepared By:	Errol Murray, Projects and Revenue Assurance Manager, Shared Services
Reviewed By:	Ken Hedley, General Manager, Shared Services
Approved By:	Ken Hedley, General Manager, Shared Services

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1 Project Overview

Rationale for Project	The Australian Energy Market Operator (AEMO) has indicated that it intends to harmonise the Retail Market Procedures and processes in all the markets in which it is market operator. To ensure that Australian Gas Networks (AGN) has sufficient resources in place to deal with these changes, it proposes to employ additional external resources to make the relevant changes to its systems. If these resources are not employed, there is a risk that AGN will be unable to make all the required changes to its systems within the timeframes set by AEMO and breach its obligations under the Retail Market Procedures. This is a particular risk for AGN given the number of jurisdictions in which it operates and the differences that currently exist across each jurisdiction.
Options Considered	Two options were considered to address the risks outlined above: • Option 1: Do nothing, which would leave AGN exposed to the risk of breaching the Retail Market Procedures if changes are not implemented within the required timeframe. • Option 2: Employ additional external resources to deal with any changes to AGN's systems that may be required as a result of mandatory changes to the Retail Market Procedures and processes.
Option Selected	Option 2 has been selected because it is the only feasible option given AGN's obligations under the Retail Market Procedures and the mandatory nature of the changes.
Estimated Cost	The forecast capital expenditure for this project is $1.821 million (real $2014/15) ($0.364 million p.a.).
Consistency with the NGR	The capital expenditure associated with this project complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because: • it is necessary to maintain the integrity of services and comply with regulatory obligations (rules 79(2) (ii) and (iii)); and • it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the *Maintain* theme because its implementation will enable AGN to continue providing safe and efficient supply of natural gas to our customers and to comply with its obligations under the Retail Market Procedures. More information on our stakeholder engagement program and results is provided in Chapter 3 of the Access Arrangement Information (AAI).

2 Background

On 1 July 2009, AEMO was accorded responsibility for the of the retail gas markets in eastern Australia. Prior to this various state based market operators were charged with the management of the retail gas markets within their respective states. While each jurisdiction operated in accordance with the National Gas Law (NGL) and National Gas Rules (NGR), different processes and practices were in place across different regions.

AEMO has indicated that it intends to harmonise these processes and practices, with the ultimate aim of establishing a single set of national procedures and systems operating across each jurisdiction as reflected in the following statement in its Guideline – Change Management Process for the Gas Retail Markets:

> *"Ultimately, the purpose of this document is to ensure that changes impacting the retail markets are applied in a uniform manner irrespective of the gas retail market."* [1]

Further detail on AEMO's change management process can be found in Appendix A.

AEMO's vision of a nationally consistent retail market means that AGN, who operates across multiple jurisdictions, must expend more resources:

- understanding the consequences and ramifications of industry (ie, retailers and/or distributors) initiated or AEMO led changes to the retail markets;[2] and
- making the required changes to its own procedures and systems to give effect to these changes.

At the time of writing, the majority of these projects are undefined, but a number are expected to occur within the next AAP and the implementation timeframe is expected to predate the 2020/21 AA review, which means that additional resources are required in this AAP. Because the cost of these projects is expected to fall below the threshold employed for cost-pass throughs, an additional allowance is required to ensure that AGN has the opportunity to recover at least the efficient costs it incurs in complying with its regulatory obligations consistent with rule 79(2)(c)(iii) and section 24 of the NGL.

2.1 Project Scope

To ensure that AGN has sufficient resources to deal with the effect of any changes to the Retail Market Procedures and processes, it intends to employ external IT resources to implement changes to its Metering and Billing, Enterprise Asset Management, GIS and Historian systems. The scope of work of this activity has been recognised as an ongoing annual cost for the duration of the next AAP to ensure it can be effectively managed. These activities are split across the national systems operated by AGN with South Australia only responsible for a proportion of these costs (based on the proportion of end-customers supplied).

1 AEMO, "Guideline – Change management process for the Gas Retail Markets", 11 December 2012, p4.

2 The need to be across these issues is greater for AGN than other distributors that only operate in a single jurisdiction.

2.2 Consistency of project with stakeholder expectations

As outlined in Chapter 3 of the AAI, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to prudently and efficiently maintain current reliability and service levels. Consistent with the above insight, the employment of additional resources to deal with changes to the Retail Market Procedures and processes will enable AGN to continue to effectively and efficiently maintain its current business operations and service levels.

3 Key Drivers and Assumptions

The key assumptions and drivers for this project are set out below:

- AEMO is moving to a national set of Retail Market Procedures and processes, which will require increased process and system changes in the next AAP. Work on this harmonisation project commenced with the Service Order Review working group, which was asked to identify the differences across all states where AEMO is the Market Operator. As a prudent operator AGN considers this increased workload requires sufficiently qualified resources to assess and implement the required changes.
- AGN maintains and considers a specific program of capital works for its IT systems, which are identified and planned for several years in advance and contribute to AGN's strategic "single platform" IT vision. These projects are in addition to this program of works.
- Gas market industry raised "ad hoc" activities have increased in recent years and require investment in their analysis and consideration.
- The timeframe for many of these projects requires immediate involvement with little or no capacity to wait for the next AAP, so AGN needs to resource appropriately.

Appendix B contains a more detailed description of the work effort required to support the change management process.

4 Risk Assessment

The key risks of not employing additional resources to deal with changes to the Retail Market Procedures and processes are outlined below:

- Potential breaches of Retail Market Procedures if market changes cannot be implemented within the required timeframes.
- Delays in implementation of market changes may occur due to lack of resources to assess the impact of the changes.
- Poor customer experience due to lost opportunities to improve consistency leading to higher overall prices to the end customer.
- Increased retailer referred complaints due to delays in implementing industry consistency programs.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria (see section 3.3 of the Asset Management Plan for further information). Further detail on the risk assessment that has been carried out can be found in Appendix C. In short, the untreated risk associated with this project has been assessed as "Moderate" from a reputational perspective and has been assigned Priority 3 rating.

5 Options

Two options have been considered as part of this business case:

- Option 1 - Do nothing; or
- Option 2 - Employ external resources to deal with mandatory changes to the Retail Market Procedures and processes.

The costs and benefits associated with these two options are set out in the table below.

Costs and benefits under the two options

Item	Option 1 – Do Nothing	Option 2 – Employ external resources to deal with changes
Costs and Risks	Without additional resources and a budget for system changes AGN may not be able to respond in a timely manner to all the nationally mandated changes and therefore breach the Retail Market Procedures. It may also result in: • the delayed implementation of market changes, which would affect AEMO, AGN and other participants in the market • poor customer experience and higher prices due to lost opportunities to improve consistency; and • a greater number of retailer referred complains due to delays.	Forecast capex $1.821 million over the AAP ($0.364 million p.a.)
Benefits	No	Ability to respond in a timely manner to changes and avoid potential breaches of Retail Market Procedures. This option can also be expected to: • avoids delays in implementation of market changes due to lack of resources; • provide for an improved customer experience due to potential ability to address/implement opportunities to improve consistency and end result customer experience with the use of gas as an energy source leading to lower overall prices to the end customer; and • avoid retailer referred complaints due to delays.

Because the work on harmonisation across all states is mandated by AEMO and the level of effort involved in implementing these changes is increasing, Option 2 is the only feasible option to achieving the objective of timely delivery of all changes. Option 2 has therefore been selected.

6 Forecast Cost for the Upcoming AAP

AGN considers it prudent to factor in capital implementation costs for several projects annually. While it is not possible to specifically identify and fully itemise the capital costs of each of these projects in the next AAP, AGN has allowed for four projects each year at a cost of $250,000 per project. This cost estimate includes the cost of project management, requirements documentation, design, system testing, bi-lateral (industry) testing, certification, implementation and training.

The table below sets out the SA gas distribution network's share of the capital expenditure that is forecast to be incurred employing these additional resources in the upcoming AAP. The proportion of costs allocated to the SA network has been based on the proportion of end customers supplied by the SA network relative to AGN's other networks.

$k (2014/15 – excluding overheads)						
	2016/17	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**Total**
External IT resources	364	364	364	364	364	1821
Total	**364**	**364**	**364**	**364**	**364**	**1821**

Finally, it is worth noting that internal staff will be used to carry out business process and system impacts assessments and design work. Because this work is already being carried out internally, no additional allowance is required for these resources.

7 Consistency with the National Gas Rules

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the additional capital expenditure that it is seeking in order to implement the changes to Retail Market Procedures and processes in the next AAP is:

- *Prudent* – The expenditure is necessary in order to ensure that the ongoing integrity of AGN's IT systems to ensure it meets its regulatory obligations. It is also of a nature that a prudent service provider would incur.
- *Efficient* – Employing additional external resources to deal with the system changes is the only practical and effective option that can be employed if AGN is to comply with its obligations under the Retail Market Procedures. The external resources will be obtained through a competitive tender process and can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur.
- *Consistent with accepted and good industry practice* – Being able to implement mandatory changes to systems in a timely manner is consistent with accepted and good industry practice.
- *To achieve the lowest sustainable cost of delivering pipeline services* – Employing the additional resources will enable the integrity of the services provided to both retailers and end customers to be maintained in the changing IT environment. Employing these resources will also allow greater consideration to be given to opportunities to improve customer experience and the most cost effective ways to implement the changes. It is therefore consistent with the objective of achieving the lowest sustainable cost of delivering pipeline services.

The capital expenditure can therefore be viewed as being consistent with rule 79(1)(a) of the National Gas Rules. The proposed capital expenditure is also consistent with rule 79(1)(b), because it is necessary to:

- maintain the integrity of services - this project is required to maintain the integrity of services both to retailers and end customers in the changing IT environment (rule 79)(2)(c)(ii)); and
- comply with a regulatory obligation or requirement – AGN's obligations under the Retail Market Procedures could be breached if its systems cannot be updated in line with national requirements (rule 79)(2)(c)(iii)).

Appendix A AEMO Change Management Process

Change Management Process for the Gas Retail Markets

National Market Operator

The Australian Energy Market Operator (AEMO) was formed as a single national organisation on 1 July 2009, to carry out the functions previously carried out by state based market operator organisations in the energy industry including Vencorp, REMCo, NEMMCO, GRMO, ESIPC and the Gas Market Company. As the market operator AEMO has carriage to determine market rules and processes to meet the obligations and requirements of the NGL and the NGR.

Prior to the formation of AEMO gas issues were considered largely on a state by state basis reflective of the gas market rules and procedures pertinent to each jurisdiction. However, since establishment of AEMO there has been a significant change in focus to a more nationalised view. AEMO have clearly and repeatedly communicated this vision of a national harmonised gas industry to the industry participants.

In late 2012, AEMO formalised this position in its published "Guideline – Change Management Process for the Gas Retail Markets[1]" document stating:

> "This industry agreed guideline outlines the change management framework for gas retail markets operated by AEMO. This document should be applied for changes to the jurisdictional Retail Market Procedures (RMP) and Technical Protocols (TPs) (together known as Procedures), which are changed in accordance with the Approved Process (AP).
>
> The scope of the change management process is bound by Part 15B of the National Gas Rules (NGR). Part 15B of the NGR outlines a list of subject matters that can be covered in the RMP and the formal Procedure change process.
>
> The change management framework in this document covers the NSW and ACT, Queensland, South Australian, and Victorian retail gas markets, as defined in Part 15A of the NGR.
>
> The change management process recognises that a change to the Procedures may also change the functionality of the retail market systems. A consistent change process enables registered participants, AEMO, and interested persons to be adequately engaged in pre-regulatory and formal consultative processes with known processes and outcomes. This framework aims to promote consistency and harmonisation of the process, timings, and regulatory obligations across jurisdictions and markets.
>
> Ultimately, the purpose of this document is to ensure that changes impacting the retail markets are applied in a uniform manner irrespective of the gas retail market."

This effectively represents a strategic change to the review and consideration of industry related issues for AGN, who ostensibly are the only national gas distributor operating across multiple states in Australia. Rather than potentially considering change issues on a state-by-state basis as was the practice under the previous regulatory hierarchy, AGN now needs to potentially consider the following artefacts as they relate to each state it operates in for each issue raised:

- Retail Market Procedures (Victoria)
- Retail Market Procedures (South Australia)
- Retail Market Procedures (Queensland)
- Retail Market Procedures (NSW and ACT)
- Gas Interface Protocol (Victoria)
- Queensland Gas Interface Protocol
- Participant Build Pack 1 - CSV Data Format Specifications
- Participant Build Pack 1 - Process Flow Diagrams
- Participant Build Pack 1 - Process Flow Table of Transactions
- Participant Build Pack 2 - Glossary
- Participant Build Pack 2 - Interface Definitions
- Participant Build Pack 2 - Usage Guide
- Participant Build Pack 3 - System Architecture
- Participant Build Pack 3 - System Interface Definitions
- Participant Build Pack 3 - System Specification
- Participant Build Pack 4 - Queensland Specific Build Pack
- Consumed Energy Scenario (Victoria)
- Consumed Energy Scenario (Queensland)
- Gas FRC B2B Connectivity Testing and System Certification
- Notice under rule 301B and 301C of the Retail Market Procedures (SA)
- Specification Pack Usage Guidelines
- SAWA Interface Control Document
- Readiness Criteria
- FRC CSV File Format
- FRC B2M-B2B Hub System Specifications
- FRC B2M-B2B Hub System Architecture
- FRC B2B System Interface Definitions
- Connectivity Testing Technical Certification

- B2B Service Order Specifications
- Gas Retail Market Business System Interface Control Document (NSW-ACT)
- Gas Retail Market Business Specifications version 6.1 (NSW-ACT)
- Operating Procedure NSW-ACT Gas Industry Protocol for identifying current Retailer
- Privacy policy for customer information for NSW ACT Lost Gas Customers

Market consultative forums

In order to facilitate the change management process, AEMO utilises consultative forums (CFs) to identify and discuss considerations concerning the making of Procedures. The CFs subsequently set up sub-working groups (WGs) to assist in the detail and operational nature of the changes proposed.

AEMO has established the Gas Retail Consultative Forum (GRCF) and the Gas Retail Consultative Forum NSW and ACT (GRCF-NA) as advisory bodies to assist AEMO in the making of Procedures. These two CFs set the strategic and regulatory direction and undertake all prioritisation for the WGs.

There are two main sub-working groups:

1. Retail Business Process Working Group (RBPWG)
   The RBPWG covers the retail business processes. This WG takes direction from the CFs regarding issues that require detailed formulation and process analysis. Activities undertaken by this group are detailed in Attachment B.

2. IT Development Forum (ITDF)
   The ITDF agrees on the adoption of proposed changes relating to the technical procedures/standards and system interfaces that impact market systems, as directed by the GRCF and GRCF-NA2.

The change management process also engages the AseXML Standards Working Group (ASWG), which is a separate working group that is not governed by the CFs. The ASWG is responsible for the development and maintenance of the aseXML standard. The ASWG reviews proposed changes to the schema, but is not responsible for the underlying business process that utilise the schema or for the processes to deliver change requests for consideration.

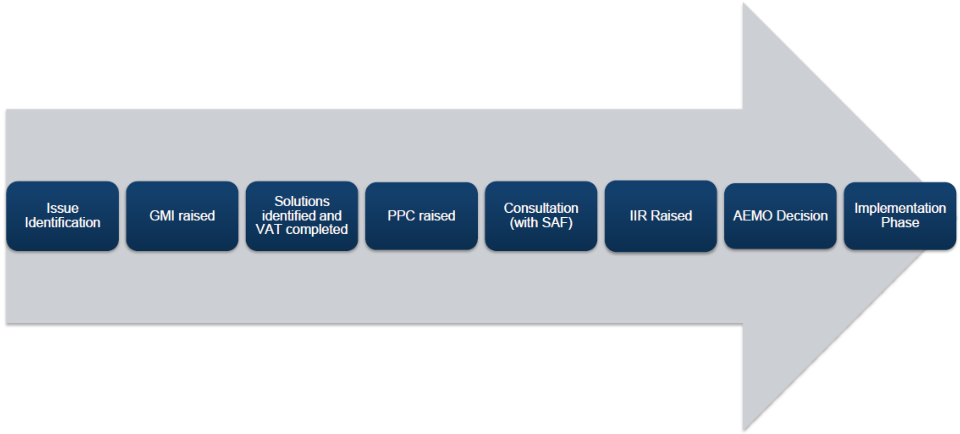
The RBPWG, ITDF, and ASWG operate in a co-operative manner to ensure any proposed changes to Procedures that impact systems and processes are cost effective.

From time to time, the CFs may also set up other WGs that utilise aspects of the change management process depending on the requirements of the CFs.

In summary, changes to market design, market rules and material changes to key procedures are initiated through these consultative forums. These forums are related in the sense that changes to the wholesale gas rules can impact on the operation of the retail market, and vice versa.

Gas Market Change Process

The forums identified previously are charged with reviewing gas market issues as per the following diagram[2]:



Note: For the avoidance of doubt, a PPC can be generated without having to raise a GMI first. If this occurs then the process set out in section 3.1 (Pre-Regulatory Process) will not apply.

In summary, the process for each issue raised by either AEMO or a market participant progresses through the following stages:

- Discussion Only (DIS)
- Gas Market Issue (GMI)
- Proposed Procedure Change (PPC)
- Stakeholder Assessment Form (SAF)
- Impact and Implementation Report (IIR)
- Awaiting Implementation (AI)

Discussion only (DIS)
This is the first stage to determine whether the issue has any support at industry level, warranting progression to the next stage. In this stage a market participant identifies an issue and raises it for discussion at the forum. The proponent may include options to resolve the issue and provide these details in the forum to determine whether the issue is progressed further.

Gas Market Issue (GMI)
Once it has been determined that there is a need and / or support for the change at industry level the issue is prepared and presented in a more formalised presentation explaining the change requirement in greater detail for MP's to review and consider via completion of a GMI template.

The GMI is progressed through Consultative Forum (CF) and/or Working Groups (WG) including review draft Procedure changes or options to remedy the issue.

CF / WG to reach consensus on the most appropriate solution to the issue and undertake a value assessment comparing do nothing and other option(s)/solution(s) are presented by the Proponent or developed in the WG.

CF considerations include:

- Regulatory implications
- Cross-jurisdictional implications
- Impact on customers
- Contractual implications
- Outcomes for the WG considerations including costs

WG considerations include:

- Impact on existing IT systems, business process, schema, testing and implementation
- Cross-jurisdictional implications
- Costs (including testing)

WG to recommend solution to CF. CF agreement is sought.
Issue moves from informal process to formal process by Proponent.

The GMI is progressed through CF and/or WGs including review draft Procedure changes or options to remedy the issue.

Proposed Procedure Change (PPC)
The Proposed Procedure Change (PPC) template allows a proponent to propose a change to the Procedures. Registering a PPC initiates the formal change processes defined in the Approved Process under the NGR.

Stakeholder Assessment Form (SAF)
The Stakeholder Assessment Form (SAF) as developed by AEMO is used by stakeholders to provide AEMO with cost / benefit data to a PPC. Information collated from SAFs is published in an aggregated form in order to address the National Gas Objective (NGO) and provide insight to participants regarding the value of the change.

Impact and Implementation Report (IIR)
The Impact and Implementation Report (IIR) is published by AEMO under the requirements of the NGR. This document provides an examination of the proposed change, an assessment of the effect of the Procedures, and a recommendation regarding whether the Procedures should be made.

Awaiting Implementation (AI)
The Release Management template describes the contents of the implementation to be managed under the Release program. This is used where there is a coordinated industry release required.

Current Volume of Industry Issues
At the time of writing this paper there are 21 issues in progress and a further 30 issues pending review.

RBPWG Functions:

The functions of the RBPWG include:

- Liaise with the GRCF and GRCF-NA and its sub-working groups to provide subject matter advice on retail market business process matters;
- Submit proposed changes to the GRCF or GRCF-NA, or review proposed changes generated by the GRCF or GRCF-NA, the responses are to include advice on any business or customer impacts;
- Identify the effort required to develop and implement solutions. This may require actions such as:
  - Development, endorsement and authorisations required for retail system changes;
  - Identification of changes to transactions, gateways, hub, business processes and data definitions that require the support of a regulatory change;
  - Development of amendments to technical protocols or any other supporting documentation; and
  - Identification of approvals and publishing updates to documentation.
- Provide a business process review, including a review of the IT systems (e.g.: IT system applications to support back office process) that support the business process and analysis of specific change proposals. This includes evaluating changes in terms of business processes and IT system applications that governs how participants interact in the retail market;
- Provide cost estimates (on a confidential basis) for Procedure changes for use in the calculation of a total industry cost;
- Provide a forum for discussion of retail market business process related issues and sharing of information and experiences;
- Identify any issues impacting the viability of the retail market or issues with market design or policy implications and escalate them to the GRCF or GRCF-NA for the CFs to set the priority;
- Provide industry expertise on technical protocols and retail business process matters; and
- Identify and document business requirements to allow options to be developed to address the issue;
- Select the appropriate option to address the issue and document the changes to the technical protocols for implementation.

Release Management Working Group Functions:

The CF may choose to establish a Release Management Working Group. The activities of the working group could include:

- Finalise scope of work for the group and develop a work program to meet the target implementation date for the release;
- Review the changes being implemented and define a program of tests;
- Develop test scripts for each of the defined tests;
- Define test data requirements and gather and collate this data;
- Define requirements for testing including environments, test harnesses, timing, likely resourcing and impact on operations;
- Document the test program;
- Define success/failure criteria;
- Document the industry implementation procedures;
- Escalate issues to CF where necessary;
- Manage the testing program;
- Manage the implementation program; and

Conduct a Post Implementation Review.

Appendix B Detailed Cost Breakdown

The table below provide a breakdown of the proposed costs of employing additional resources to deal with changes to the retail market procedures and processes across all of AGN's networks. All values in these tables are expressed in $'000 $2014/15 values and exclude overheads.

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Requirements documentation	240	240	240	240	240	1,200
Design	400	400	400	400	400	2,000
Testing	176	176	176	176	176	880
Bi-lateral testing	32	32	32	32	32	160
Certification	24	24	24	24	24	120
Implementation	48	48	48	48	48	240
Support	80	80	80	80	80	400
Total	1,000	1,000	1,000	1,000	1,000	5,000

A more detailed breakdown of the assumptions underlying the $1 million p.a. cost is provided in the table below.

Capex	Days			
Projects progressing	4			
External contractors				
	Days	Resources	Rate	Cost
Effort required				
Requirements documentation	15	2	$ 2,000	$ 60,000
Design	25	2	$ 2,000	$ 100,000
Testing	11	2	$ 2,000	$ 44,000
Bi-lateral testing	2	2	$ 2,000	$ 8,000
Certification	3	1	$ 2,000	$ 6,000
Implementation	3	2	$ 2,000	$ 12,000
Support	5	2	$ 2,000	$ 20,000
Time per project / Issue	64			$ 250,000
Annual Total Capex Cost	$1,000,000			
Daily Rate - External	$ 2,000.00			

The manner in which these costs have been allocated to AGN's SA network is set out in the table below (all values in this table are expressed in $'000 $2014/15 values and exclude overheads).

	Customer Numbers	%	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
South Australia	**431,041**	**36%**	**364**	**364**	**364**	**364**	**364**	**1821**
Victoria	631,851	53%	534	534	534	534	534	2669
Queensland	92,852	8%	78	78	78	78	78	392
NSW	27,900	2%	24	24	24	24	24	118
Total	1,183,644		1000	1000	1000	1000	1000	5000

Appendix C Risk Assessment

The top panel in the table below sets out the results of the risk assessment assuming no additional resources are employed (untreated risk), while the bottom panel sets out the residual risks if the resources are employed. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environmental	Operational	Customers	Reputational	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	Rare	Rare	Rare	Rare	Unlikely	Possible	Rare	
	Consequence	Insignificant	Insignificant	Minor	Insignificant	Medium	Minor	Insignificant	
	Risk Level	Negligible	Negligible	Negligible	Negligible	Moderate	Low	Negligible	
		1	1	3	1	12	8	1	27

		Health & Safety	Environmental	Operational	Customers	Reputational	Compliance	Financial	Total Score of Risk Levels
Risk after project	Likelihood	Rare	Rare	Rare	Rare	Rare	Unlikely	Rare	
	Consequence	Insignificant	Insignificant	Minor	Insignificant	Medium	Minor	Insignificant	
	Risk Level	Negligible	Negligible	Negligible	Negligible	Low	Low	Negligible	
		1	1	1	1	6	5	1	16
					Cumulative Risk Reduction				11

Priority	Priority Description
Priority 1	Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2	Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3	Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4	Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE SA69

PROJECT REFERENCE	
Network	AGN- SA
Project No.	SA69
Project Name	Fencing critical infrastructure
Budget Category	Capex
Priority	3
Reference Docs	N/A
Confidentiality Claim	Yes (throughout document, for security reasons, Attachment A for input cost reasons)
PROJECT APPROVAL	
Prepared By:	Robin Gray, *Manager Systems Operations* and Annabel Sandery, *Project Engineer*
Reviewed By:	Robin Gray, *Manager Systems Operations*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 PROJECT OVERVIEW

This project is to improve the security of critical infrastructure sites within the network.

[redacted]

[redacted]

[redacted]

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Improve theme as it improves network reliability and safety.

2 COST AND TIMING

The scope of work of the project has been spread across two years to ensure the program can be effectively managed.

The costs of this project have been based on the costs of similar construction works carried out over the last few years, resulting in the following unit costs:

- Fencing Supply and Install $830/lm
- Ground preparation by APA crews $2,000/site
- Regional travel and site set up $3,000/site
- Supervisor rates $80/hr

A summary of Capex is in the table below. A detailed cost break down is included in Attachment A.

$'000s (2014/15 – excluding overheads)						
Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Sites	6	4				10
Total Cost	267	167				434

3 BACKGROUND

[redacted]

[redacted]

[redacted]

[redacted]

Ten existing sites have been identified for upgrade in security as detailed in Attachment B.

4 KEY DRIVERS & ASSUMPTIONS

The key drivers and assumptions for this project are:

- [redacted]
- [redacted]
- [redacted]

5 RISK ASSESSMENT

[redacted]

[redacted]

[redacted]

6 OPTIONS

Two options were considered:

[redacted]

[redacted]

Cost Benefit Analysis

[redacted]

[redacted]

[redacted]

Capex / Opex Trade-off

[redacted]

7 JUSTIFICATION

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules (NGR), AGN considers that the capital expenditure is:

- *Prudent* – the expenditure is necessary to minimise the threat to critical above ground infrastructure [redacted];
- *Efficient* – The cost estimate is based on historical tendered costs for labour and materials;
- *Consistent with accepted and good industry practice* – The ongoing identification of threats and risks is an operator's obligation as per Australian codes governing gas transmission and distribution assets (AS 2885 and AS 4645);
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – The additional costs to reduce the identified risk is considered small [redacted] and as such is consistent with providing services at lowest sustainable costs.

AGN considers that the capital expenditure is justifiable under rule 79(2)(c)(i) and (ii) of NGR as the expenditure is necessary in order to maintain and improve the safety of services and maintain the integrity of services.

8 PROJECT DELIVERY

AGN confirms that it has the appropriate resources necessary to deliver the project in the required timeframe.

Work is to be undertaken by qualified contractors with instruction/supervision by internal personnel.

9 CONSEQUENCES OF NOT PROCEEDING

[redacted]

ATTACHMENT A – Detailed Cost Breakdown

$'000s (Real 2014/15 – excluding overheads)						
Item	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
[redacted]	[redacted]	[redacted]				
[redacted]	[redacted]	[redacted]				[redacted]
[redacted]	[redacted]	[redacted]				[redacted]
[redacted]	[redacted]	[redacted]				[redacted]
[redacted]	[redacted]	[redacted]				[redacted]
[redacted]	[redacted]	[redacted]				[redacted]
[redacted]	[redacted]	[redacted]				[redacted]
Total	**267**	**167**				**434**

ATTACHMENT B – Critical Infrastructure Sites

Site Location	Station type	Lineal Metres of Fencing
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

ATTACHMENT B –Risk Assessment

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance	Financial Impact	Total Score of Risk Levels
Risk Untreated	Likelihood	Possible	Possible	Possible	Possible	Possible	Possible	Possible	
	Consequence	Minor	Minor	Medium	Minor	Medium	Medium	Medium	
	Risk Level	Low	Low	Moderate	Low	Moderate	Moderate	Moderate	80
		08	08	14	08	14	14	14	
Residual Risk	Likelihood	Rare	Rare	Rare	Rare	Rare	Rare	Rare	
	Consequence	Minor	Minor	Medium	Minor	Medium	Medium	Medium	
	Risk Level	Negligible	Negligible	Low	Negligible	Low	Low	Low	36
		03	03	06	03	06	06	06	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA70

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA70
Project Name	Transmission Valve Replacement
Budget Category	Capex
Priority	2
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachment B)
PROJECT APPROVAL	
Prepared By:	Annabel Sandery, *Project Engineer* and Robin Gray, *Manager Systems Operations*
Reviewed By:	Robin Gray, *Manager Systems Operations*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 PROJECT OVERVIEW

It is planned to replace six DN 300 seized transmission valves, within Australian Gas Network's (AGN) Adelaide distribution system, and to relocate three of these so that they are not in main roads and intersections.

The scope of work includes hot tap, stoppling and installation of a bypass, as these valves cannot be isolated without severely affecting network supply. The valves will be cut out and replaced, and in three cases the pipework altered to accommodate relocation of the valve to a safer position. Refer to Attachment A for valve location details.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Maintain theme as it maintains network reliability.

2 COST AND TIMING

The costs of this project have been based on:

- Actual costs of undertaking similar project work on transmission pipework;
- Supervisor, technician and traffic control costs at current rates.

A summary of Capex is provided in the table below. Detail cost break down is included in Attachment B.

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Materials	15.0	30.0	155.0	155.0	155.0	**510**
Direct Labour Costs	20.8	41.6	29.6	29.6	29.6	**151**
Contract Services	6.3	12.6	73.5	73.5	73.5	**239**
Total	**42**	**84**	**258**	**258**	**258**	**900**

3 BACKGROUND

The Adelaide distribution system has 80 large diameter steel network isolation valves, ranging in size from 200mm to 300mm, which are used for emergency isolation and or pressure reduction.

The majority of these valves were installed in the late 1960s and early 1970s and are located on major trunk mains or branches off the major trunk mains within major transport corridors.

The valves are located in underground concrete and brick chambers that are accessed via a manhole cover located in the roadway or in the footpath. These chambers are cramped with limited room for maintenance and are difficult to access, in particular those located in busy carriageways.

The valves are subject to corrosion from the high humidity in the chambers and in some cases the valve/pipe joints are subject to stresses from heavy traffic vibration.

Six of these valves have ultimately seized and are now inoperable. There have been many attempts to flush and regrease these valves to no avail. Three of these valves are located in the middle of major roads presenting a significant risk to the safety of the maintenance personnel when accessed for maintenance or in response to network incidents requiring pressure control.

The existing valves cannot be isolated for repair without severely affecting the network supply. Replacement of these valves will require hot tap and stoppling with bypasses fitted to maintain supply.

Three valves will be replaced in their current location, while the other three valves will be relocated to locations that are safer to access.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for the project are:

- Valves are key components of the network and are required to be operational for emergency isolation and control purposes. Six inoperable transmission valves would impede emergency response;
- Response to emergencies within the Adelaide distribution network is impeded as result of six inoperable transmission valves;
- The location of valves within major roads and intersections is a major hazard for maintenance and pressure control operations; and
- The replacement of these valves will require installation of a temporary bypass to maintain supply.

5 RISK ASSESSMENT

The risk of inoperable key valves is a delayed response to an emergency and consequently a longer time required to contain or prevent a major gas escape.

Resorting to alternative valves upstream or downstream to an emergency gas escape would result in significantly more consumers impacted by reduced operating pressures or, in a worst case scenario, loss of supply.

The location of valves in a major road presents a safety risk to maintenance personnel who have to maintain and operate these valves.

A risk assessment has been carried out using APA’s established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA’s established risk management and control criteria.

The untreated risk associated with this project has been assessed as "High", given the risk associated with a major gas escape resulting in an interruption to supply, and has been assigned Priority 2. Refer to the risk assessment matrix in Attachment C.

6 OPTIONS

There are no viable alternatives to replacement and relocation to reduce operational and maintenance risks.

Cost Benefit Analysis

Not applicable, as this project is related to reduction of risk.

Capex / Opex Trade-off

Substitution between operating and capital expenditure is not relevant in respect of this project.

7 JUSTIFICATION

Consistent with the requirements of rule 79 of the National Gas Rules (NGR), AGN considers that the expenditure is:

- *Prudent* – the expenditure is necessary in order to maintain and improve the safety of services and maintain the security and integrity of services.

  These valves are critical for emergency isolation and pressure control. Failure to address the inoperable valves could result in delays in emergency situations posing a danger to the public and to personnel;

- *Efficient* – AGN has based costs on previous similar transmission pipeline project (labour and material) costs.
- *Consistent with accepted and good industry practice* – maintaining critical isolation valves for emergency control is a code (AS2885) requirement as is identification and reduction of risks to as low as reasonably practicable; and
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* –maintaining a network in accordance with a design that meets Code and industry standards is necessary to deliver services in a cost effective and sustainable manner.

AGN considers that the capital expenditure is justifiable under rule 79(2)(c)(i) and (ii) of the National Gas Rules as the expenditure is necessary in order to improve the safety and integrity of services.

8 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken there is a risk that emergency response in certain situations will be hindered, leading to an increased risk of a serious incident, as well as potential for loss of supply to a large number of consumers.

There is also an increased risk of injury to personnel when trying to access valves in high traffic locations.

ATTACHMENT A – Valve Location Details

Valve No	Streets	Suburb	Action
1034	Weymouth Road	Newton	Relocation & Replacement
830	Cormack Road/Plymouth	Wingfield	Replacement
286	Bridge Road/Yatala Vale road	Smithfield	Relocation & Replacement
292	Chief street	Brompton	Replacement
290	Refinery road	Lonsdale	Replacement
289	Churchill road	Kilburn	Relocation & Replacement

ATTACHMENT B - Detailed Cost Breakdown

Valve Replacement Costs - $'000						
	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	Total
Valves to be replaced	1	2				**3**
Valves to be replaced and relocated*			1	1	1	**3**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Total	**42.1**	**84.2**	**258.1**	**258.1**	**258.1**	**900.6**

* Additional scope associated with mains alteration to new location

ATTACHMENT C - Risk Assessment

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance	Financial Impact	Total Score of Risk Levels
Risk Untreated	Likelihood	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Medium*	*Minor*	*Significant*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Low*	*High*	*Low*	*Low*	*Moderate*	*Low*	*80*
		14	*08*	*20*	*08*	*08*	*14*	*08*	
Residual Risk	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Medium*	*Minor*	*Significant*	*Minor*	*Minor*	*Medium*	*Minor*	
	Risk Level	*Low*	*Negligible*	*Moderate*	*Negligible*	*Negligible*	*Low*	*Negligible*	*35*
		06	*03*	*13*	*03*	*03*	*06*	*01*	

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE - SA71

PROJECT REFERENCE	
Network	AGNL - SA
Project No.	SA71
Project Name	326 – TP – Murray Bridge Augmentation
Budget Category	Capex
Priority	3
Reference Docs	2015 South Australia Network Asset Management Plan
Confidentiality Claim	Yes (Attachments C,D)
PROJECT APPROVAL	
Prepared By:	Vanessa Co, *SA Networks Asset Planning Manager*
Reviewed By:	Keith Lenghaus, *Victoria Networks Asset Planning Manager*
Approved By:	Jan Krzys, *Networks Asset Strategy and Planning Manager*

1 PROJECT OVERVIEW

To accommodate organic growth within Murray Bridge, it is required to upgrade the capacity of supply to the Murray Bridge township regulator station by laying a 2 km DN 150mm transmission pressure steel main from the Murray Bridge Gate Station to the Murray Bridge township regulator station. Refer Attachment A for concept plan details.

The scope of work includes:

- 2km x DN 150mm transmission steel main from the existing DN 100 connection on the 1,650kPa side of the Murray Bridge Gate Station; and
- Connect the existing Murray Bridge regulator station to the new DN 150mm transmission main.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Maintain theme as it maintains network reliability.

2 COST AND TIMING

Costs for this project have been based on recent similar projects that have undergone a competitive tendering process.

The following table provides a summary of forecast costs of the project. A detailed cost breakdown has been provided in Attachment C.

The delivery of the project is planned to be phased over 2 years. The front end engineering design (FEED) will be undertaken in FY 17/18 to confirm design specification and ordering of any long lead items with construction and commissioning timed to be complete prior to the 2019 winter.

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Materials		182	73			255
Labour		312	2,444			2,756
Total		494	2,517			3,011

3 BACKGROUND

Natural gas is supplied to the Murray Bridge township via a 2 km small diameter (DN50) steel transmission pressure (TP) main ex the Murray Bridge gate station. The transmission main is operating close to its maximum capacity.

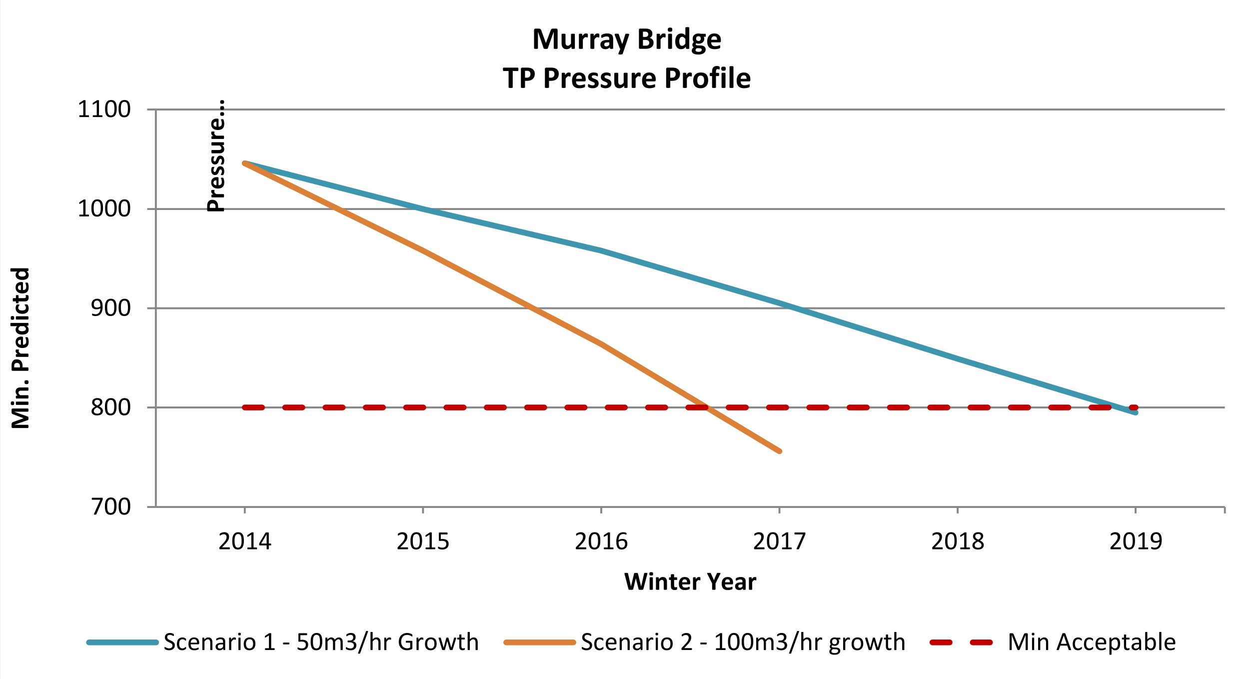
Gas is supplied to 4 major demand consumers and about 400 Tariff V consumers within the Murray Bridge township.

AGN is forecasting 2 existing northern estates (>900 allotments), 3 new northern estates near the town's racecourse (approximately 100 allotments) and Gifford Hill development (an initial 300 allotments expanding to about 1,750 allotments) over the next 15 -20 years. Refer to Attachment B for development location details. These developments are expected to result in about 250-300 new gas connections per year.

Historically peak hour growth within the township has been of the order of 50 m3/hr per year. The new developments as outlined above are expected to increase this to about 100m3/hr per year.

In addition to "organic" growth referred to above, there is potential for several industrial/commercial and Demand connections in the township of Monarto over the next 15 years (total demand circa 10,000 m3/hr). Supply to Monarto would be via a TP pipeline just upstream of the Murray Bridge township regulator. The timing of this development hinges on the timing of a number of foundation customers.

The following graph summarises the outcome of network modelling of transmission pressures upstream of the Murray Bridge township regulator.



Scenario 1 - Based on annual growth of 50m3/hr (historic growth).

Scenario 2 – Based on annual growth of 100m3/hr (forecast 250 new residential consumers per year, see Attachment D for detailed cost breakdown).

Depending on future demand profiles from the existing Tariff D consumers and forecast residential growth, the TP pipeline is expected to exceed capacity between 2016 and 2018.

Given that there may be some lag between housing construction and additional gas load materialising, it is less likely that augmentation will be required by 2017. However, the timing is very sensitive to the demand profiles of the existing Tariff D consumers. A 10% increase in demand would bring forward augmentation by 2 years. Conversely a 10% decrease could defer augmentation by 2 years.

For purposes of planning it is assumed augmentation will be required by 2019 with annual review of network demand to confirm actual timing.

4 KEY DRIVERS & ASSUMPTIONS

The key assumptions and drivers for the recommended project are:

- Growth of peak hour demand will be between 50-100 m3 per hour per year.
- It is assumed that there will be no new Tariff D customers or material increase in demand from existing customers.
- Capacity of the TP pipeline will be reached by 2018.
- There is potential for significant “step out” loads in the nearby Township of Monarto.

5 RISK ASSESSMENT

Operating a gas supply main to Murray Bridge at lower than minimum acceptable pressure creates the risk of gas outages to the entire township.

From an operational perspective loss of supply of up to 400 existing customers would be at risk if the network was not augmented.

A risk assessment has been carried out using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria.

This project has been rated as "Moderate" as per APA risk matrix (details in Attachment E) and has been assigned Priority 3.

6 OPTIONS

Two options were considered based on upgrading the delivery pressures to the township regulator. These are summarised in the following table.

Option	Description	Cost $'000	Useful Life Yrs	Risk Red'n Score	Cost Per Yr	Cost Per Unit Risk
Option 1	2.1 km DN150 steel TP main (project proposal)	3,011	20+	40	151	75
Option 2	As per Option 1 with DN100 steel TP main	2,940	20+	40	147	74

Option 1 will accommodate organic growth in Murray Bridge as well as having capacity to service a large portion (60%) of the potential loads at Monarto.

Option 2 will accommodate organic growth in Murray Bridge as well as having capacity to service a small portion (20%) of the potential loads at Monarto.

The $70k premium of Option 1 would translate to a future value (@ 10%) of about $180K after 10 years and $470k over 20 years. The premium would avoid future augmentation (circa $3M) of the TP pipeline should gas supply to Monarto proceed.

Option 1 is considered the most cost effective long term solution to service growth within the region.

Capex / Opex Trade-off

There is no opportunity to substitute Opex for Capex in this instance.

7 JUSTIFICATION

Consistent with the requirements of Rule 79 of the National Gas Rules, AGN considers that the expenditure is:

- *Prudent* – The expenditure is necessary in order to improve the integrity of existing services. Operating below recommended minimum pressure puts the reliable supply of gas at risk.
- *Efficient* – The cost estimates for this project are based on actual costs for similar works that have been based on competitive tender rates for labour, materials and fittings. The recommended option represents the most cost effective long term solution as detailed above.
- *In accordance with good industry practices* – Gas utilities across Australia are obligated to reduce risks within their networks to as low as reasonably practicable. Maintaining a safe and reliable supply of gas by maintaining adequate system pressures is consistent with this objective.
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – Proactively addressing future gas supply issues will avoid short term multiple reactive measures, thereby ensuring the lowest long term sustainable cost.

AGN therefore considers that the capital expenditure is justifiable under 79(1) (a) rule and rule 79(2)(c)(i) and (ii) of the National Gas Rules as the expenditure is necessary in order to maintain and improve the safety and integrity of existing services, which AGN interprets to include the security of supply of its services.

8 CONSEQUENCES OF NOT PROCEEDING

If this project is not undertaken, AGN will be exposed to consequences associated with insufficient network capacity to feed organic growth projections. These include:

- Potential loss of supply to about 400 existing consumers;
- Resorting to short term reactionary augmentations, costing more in the long term;
- Loss of future revenue; and
- Loss of reputation of gas as a reliable fuel.

Attachment A – Concept Plan

Attachment B – Network Map of Future Organic Growth Areas

Note: Growth areas are in shaded yellow areas

ATTACHMENT C – Detailed Cost Breakdown

Option 1 (Recommended) Costs

[redacted]

ATTACHMENT D – Detailed Cost Breakdown

Option 2 Costs

[redacted]

ATTACHMENT E – Risk Assessment

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels
Risk Untreated	Likelihood	*Possible*	*N/A*	*Possible*	*Possible*	*Possible*	*Possible*	*Possible*	
	Consequence	*Minor*	*N/A*	*Medium*	*Medium*	*Medium*	*Medium*	*Insignificant*	
	Risk Level	*Low*	*Negligible*	*Moderate*	*Moderate*	*Moderate*	*Moderate*	*Negligible*	**68**
		08	*N/A*	*14*	*14*	*14*	*14*	*04*	
Residual Risk	Likelihood	*Rare*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
Option 1	Consequence	*Minor*	*N/A*	*Medium*	*Medium*	*Medium*	*Medium*	*Insignificant*	
	Risk Level	*Negligible*	*N/A*	*Low*	*Low*	*Low*	*Low*	*Negligible*	**28**
		03	*N/A*	*06*	*06*	*06*	*06*	*01*	
								Cumulative Risk Reduction for Option 1	**40**
Residual Risk	Likelihood	*Rare*	*N/A*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
Option 2	Consequence	*Minor*	*N/A*	*Medium*	*Medium*	*Medium*	*Medium*	*Insignificant*	
	Risk Level	*Negligible*	*N/A*	*Low*	*Low*	*Low*	*Low*	*Negligible*	**28**
		03	*N/A*	*06*	*06*	*06*	*06*	*01*	
								Cumulative Risk Reduction for Option 2	**40**

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE – SA 75

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA75
Project Name	Relocate meters in vulnerable locations
Budget Category	Capex
Priority	3
Reference Docs	
Confidentiality Claim	No
PROJECT APPROVAL	
Prepared By:	Peter Sauer, *General Manager SA Networks* and Dominic Zappia, *Manager Planning and Engineering*
Reviewed By:	Dominic Zappia, *Manager Planning and Engineering*
Approved By:	Peter Sauer, *General Manager SA Networks*

1 PROJECT OVERVIEW

AGN have previously installed gas metering infrastructure to properties in compliance with good industry practice. Changes are often made to the layout of properties through building, subdivision, alteration of vehicular entry and exit points which results in that gas infrastructure being exposed to the risk of damage or installed in inappropriate locations.

This proposal is for APA to move the meter without charge to the individual on the basis that it:

- eliminates the safety risk associated with these installations;
- reduces the need to attend to repair gas escapes as a result of damage; and
- improves efficiency by carrying out this work when work would otherwise need to be performed at the property.

AGN has undertaken a comprehensive stakeholder engagement program to better understand the values of stakeholders. Details of the program and results are provided in Chapter 3 of the Access Arrangement Information document. A key outcome of this program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Improve theme as it improves network safety.

2 COST AND TIMING

The costs are based on average cost for jobs quoted during the 2013/14 financial which was $1,560 per job (ex GST).

A summary of Capex by financial year is provided in the following table, detailed costing is shown in Attachment A.

$'000s (2014/15 – excluding overheads)						
Item	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Meter relocation	468	468	468	468	468	**2,340**

3 BACKGROUND

Gas meters installed at properties are often left in vulnerable positions following building and or construction work undertaken years after the original installation.

This comes about through building extensions/additions, installation of fences and gates, urban consolidation driving subdivision of larger blocks and change of ownership of properties resulting in change of "driveway location". Meters left in these locations are susceptible to damage and are on occasion hit by vehicles and subject to vandalism. Some create unsafe conditions and when identified are targeted for repair and or disconnection.

There are around 300 residential and small/industrial enquiries annually to alter the position of meters. APA as AGN's operator, attended site and provide a quote to move the infrastructure which generally involves alteration of both the inlet connection to the main and the consumer's outlet service.

Consumers are given a quote to shift the meter to an agreed location however many elect not to proceed leaving the meter vulnerable to damage to which case AGN must respond, often after hours and in an emergency situation.

To avoid the cost some consumers have been known to organise disconnection and shortly after apply for a new connections in the location that the meter is required.

It is proposed that AGN perform the work of relocating vulnerable meters to a safe location without cost to the individual consumer and recover the cost across all users, as it results in safer operation of the system and improved efficiency.

Failure to undertake the work as Capex in a controlled manner results in work being performed as Opex often is emergency and after hours situations.

4 KEY DRIVERS & ASSUMPTIONS

- Failure to relocate meters in vulnerable locations creates a safety risk for consumers and the public.
- Consumers who elect not to move a meter create situations which make future work on the meter almost impossible as inlet and outlet pipes become encased in concrete, are built around, or are inaccessible.

5 RISK ASSESSMENT

- Failure to relocate creates a risk to the integrity of the asset from damage and or vandalism.
- Damage usually results in uncontrolled gas escape and attendance of emergency services to control the leak.
- There have been instances of ignition following damage but any leak creates opportunity for fire/explosion.
- Consumers in this position do and may continue to apply for disconnection of supply and subsequently apply for a new gas connection. The cost of which is greater than the average cost of relocation.

6 OPTIONS

- Do nothing – will result in the current situation where vulnerable meters are retained with the inherent risks and costs as outlined above.
- Relocate these vulnerable meters identified in inappropriate locations at no cost to the consumer. This eliminates the risk of damage and the need to respond to emergency work.

Cost Benefit Analysis

- Undertaking the work as Capex will minimize the potential for emergency situations and minimize the opportunity for and impact of gas leakage.

Capex / Opex Trade-off

- Performing the work as planned Capex reduces the potential to have to attend to uncontrolled leaks and their repair.

7 JUSTIFICATION

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the capital expenditure is:

- *Prudent* – the expenditure is necessary in order to maintain and improve the safety of services to customers and the public by ensuring that gas from damaged infrastructure does not occur creating potential damage to life and property.
- *Efficient* – avoids the costly process of quoting and non-acceptance and the avoidance of APA responding to emergencies which often occur after hours at night where driver visibility is inhibited.
- *Consistent with accepted and good industry practice* – if the consumer with a meter in an inappropriate/vulnerable location were to apply for a gas connection the meter would not be located where it currently is. The purpose of relocating meters is to remove the risk to consumers emergency services and gas workers associated with responding to gas leaks.
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – Reducing public risk is fundamental to the sustainable delivery of pipeline services. Planned relocation minimizes the necessity of having to respond in emergency situations.

The capex is also justifiable under rule 79(2)(c) parts (i) and (ii), for the reasons set out above.

The capital expenditure is justifiable under rule 79(2)(c)(i) and (ii) of the National Gas Rules as the expenditure is necessary in order to maintain and improve the safety of services and maintain the integrity of service.

8 PROJECT DELIVERY

AGN confirms that it will use a combination of internal and external resources to deliver the recommended project. Internal resources to plan and control the work and contractors to perform the work in the field.

9 STEP CHANGE NOT IN BASE YEAR COSTS

Not applicable for Capex projects.

10 CONSEQUENCES OF NOT PROCEEDING

Failure to proceed will result in :

- At risk meters being retained in locations that create a danger to the public, consumers, and APA gas workers when damage occurs requiring response.
- Gas meters and associated pipework becoming embedded in concrete and or built in to the extent that they become inaccessible and unable to be worked on.
- Consumers electing to not reposition gas meters that are or will be impacted by onsite construction activity.

ATTACHMENT A – Detailed Cost Breakdown

Description	Units	Total $'000
300 relocations PA at average cost of $1,560 based on previous years quotes.	300	468
Supervision is included in current base cost as Opex as no additional resources are required.	0	0
No additional vehicles and or equipment are required.	0	0
Total per year		**468**

ATTACHMENT B – Risk Assessment

		Health & Safety	Environment	Operational	Customer	Reputation	Compliance	Financial Impact	Total Score of Risk Levels
Risk Untreated	Likelihood	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	*Occasional*	
	Consequence	*Medium*	*Insignificant*	*Insignificant*	*Insignificant*	*Medium*	*Medium*	*Minor*	
	Risk Level	*Moderate*	*Low*	*Low*	*Low*	*Moderate*	*Moderate*	*Low*	
		18	*07*	*07*	*07*	*18*	*18*	*10*	*85*
Residual Risk	Likelihood	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	*Rare*	
	Consequence	*Medium*	*Insignificant*	*Insignificant*	*Insignificant*	*Medium*	*Medium*	*Minor*	
	Risk Level	*Low*	*Negligible*	*Negligible*	*Negligible*	*Low*	*Low*	*Negligible*	
		06	*01*	*01*	*01*	*06*	*06*	*03*	*24*

Priority		Priority Description
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to APA.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non-inclusion of these projects may expose APA, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non-inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non-inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

BUSINESS CASE – SA77

PROJECT REFERENCE	
Network	AGN – SA
Project No.	SA77
Project Name	Monarto Front-End Engineering Design (FEED) Study
Budget Category	Opex
Risk Rating	Low
Confidentiality Claim	Yes
PROJECT APPROVAL	
Prepared By:	Ed Macolino, *Manager Strategic Development*
Reviewed By:	Peter Gayen, *Networks Commercial Manager*
Approved By:	John Ferguson, *Group Executive Networks*

1. Project Overview

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BUSINESS CASE – SA82

PROJECT REFERENCE	
Network	AGN– SA
Project No.	SA82
Project Name	Infrastructure Renewal
Budget Category	SIB Capex
Risk and Priority	High, Priority 2
Reference Docs	2015 South Australia Network IT Investment Plan
Confidentiality Claim	No
PROJECT APPROVAL	
Prepared By:	Simon Mackay, *Infrastructure & Support Manager, Information Technology*
Reviewed By:	Heather Reynolds, *Vendor Manager Information Technology*
Approved By:	Bill Fazl, *General Manager Information Technology*

1 Project Overview

Rationale for Project	The Infrastructure Renewal project involves the upgrade of desktop infrastructure and telephony infrastructure over the upcoming Access Arrangement Period (AAP). The upgrade of this infrastructure will ensure that AGN continues to maintain reliable, compliant and efficient business processes and systems and preserves the on-going integrity of the services. If the project is not carried out, the IT systems may be exposed to higher security risk, a greater number of failures may occur and AGN may be unable to address strategic imperatives and architectural weaknesses identified in the IT Strategic Plan.
Options Considered	Two options were considered as part of this business case: • Option 1: Upgrade the desktop and telephony infrastructure in the upcoming AAP. • Option 2: Defer the renewal until the subsequent AAP (FY 2021/22-2025/26).
Option Selected	Option 1 was selected because deferring the replacement of the telephony infrastructure is not a viable option given the age of this infrastructure and the vendor release cycles. Implementing Option 1 is also expected to: • reduce AGN's exposure to system and security related vulnerabilities and unplanned outages from the failure of critical infrastructure • reduce the risk of non-compliance with Retail Market Procedures; • improve the stability of the IT systems and enable core infrastructure to be supported by IT vendors; • Integrate and enhance communications channels and enable new capabilities to be realised through applications and service offerings.
Estimated Cost	The forecast capital expenditure for the Infrastructure Renewal project is $1.022 million (real $2014/15).
Consistency with the NGR	The expenditure on the Infrastructure Renewal project complies with the new capital expenditure criteria in rule 79 of the National Gas Rules because it is: • necessary to maintain and improve the safety of services, maintain the integrity of services and comply with regulatory obligations (rules 79(2)(i), (ii) and (iii)); and • such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.
Stakeholder Engagement	A key outcome of AGN's stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This project is consistent with the Maintain theme because its implementation will allow AGN to continue providing reliable and efficient supply of natural gas to our customers.

2 Background

The Infrastructure Renewal project involves the upgrade of the following pieces of AGN infrastructure in the next Access Arrangement Period (AAP):

- **Desktop Infrastructure –** The desktop operating platform is six years old and is typically refreshed on a 3-7 year cycle. The Next Generation Operating Environment stream will upgrade all corporate systems to the Windows 8/10 Operating System. This will provide a robust platform that underpins strategic application initiatives. The platform also allows the business to leverage new capabilities including touch screen, modernisation of the corporate desktop and mobility solution offerings. At the completion of this upgrade AGN's South Australian Network will be supported by a robust enterprise desktop platform that aligns to key Enterprise IT systems.
- **Telephony Infrastructure -** The telephony infrastructure is over ten years old and the increasingly scarce availability of spare parts represents a business risk. The Unified Communications stream will replace legacy telephony hardware with a solution that integrates telephony, presence, voicemail and conferencing across the enterprise. At the completion of this upgrade, AGN's South Australian Network will be supported by a robust enterprise telephony infrastructure that supports key Enterprise IT systems.

The upgrade of these two pieces of infrastructure will enable AGN to maintain reliable, compliant and efficient business processes and systems and preserves the on-going integrity of services. It will also ensure the continued secure and supported[1] operation of desktop and telephony infrastructure and, in doing so, will:

- improve the security and integrity of business information;
- improved the stability of IT systems over time;
- integrate and enhance communications channels across the business;
- provide AGN with continued access to relevant support and spare parts; and
- enable compliance with the latest IT systems with market requirements.

Some of the specific benefits associated with the two infrastructure upgrades are outlined below:

- Desktop infrastructure - Modernisation of the desktop, office and mobility platforms will:
  - reduced AGN's exposure to system and security related vulnerabilities;
  - allow new capabilities to be realised including touch screen and stylus for mobility;
  - provide a modern platform for leveraging new capabilities; and
  - provide for collaboration application and services offerings.

[1] Continuation of IT vendor support, which will require movement to a recent version of the relevant software.

- Telephony infrastructure – Upgrading this infrastructure will provide for:
  - a modern, supported, resilient communication and collaboration platform;
  - an integrated and enhanced communications channels across the business; and
  - the capability to leverage future line of business and communication integrations.

2.1 Consistency of project with stakeholder expectations

As outlined in Chapter 3 of the AA Information, AGN has undertaken a comprehensive engagement program to better understand the values of our stakeholders. During this engagement, stakeholders told us that they viewed gas as a reliable source of energy and indicated that they would like us to prudently and efficiently maintain current reliability and service levels. Consistent with the above insights, the Infrastructure Upgrades project will enable AGN to continue to provide reliable and efficient supply of natural gas to customers.

3 Risk Assessment

The key risks of not carrying out the renewal program are as follows:

- IT systems may be exposed to increasing security risks if the systems are outside the supported lifecycle.
- An increased rate of failure in older infrastructure may occur, which could result in unplanned production outages.
- Increased risk and exposure of communications both within the business and customers if the current telephony infrastructure is not replaced.
- AGN may be unable to address strategic imperatives and architectural weaknesses identified in the IT Strategic Plan.

AGN has carried out an assessment of these risks using APA's established evaluation criteria to produce an estimated level of risk and to rank and prioritise the risk based on APA's established risk management and control criteria. This has entailed identifying existing and potential network operational risks (and residual risks) in terms of the consequences and the likelihood of the risk. Further detail on the risk assessment that has been carried out can be found in Attachment A.

In short, the untreated risk associated with the matters outlined above has been assessed as high from an operational perspective and accorded a Priority 2 rating.

4 Options

Two Options were considered as part of this business case:

1. Upgrade desktop and telephony infrastructure in the upcoming AAP:
   This is the only option to address the risks associated with the failure to upgrade critical business IT infrastructure.
2. Defer the infrastructure renewal until the subsequent AAP (FY 2021/22-2025/26).

The costs and benefits associated with these two options are summarised in the table below.

Costs and benefits of the options

Item	Option 1: Upgrade infrastructure in this AAP	Option 2: Upgrade infrastructure in the subsequent AAP
Costs/Risks	$1.022 million (real $2014/15).	Due to the timeframe of vendor release cycles, and the current age of telephony infrastructure, this is not considered to be a prudent solution because it will expose AGN to the following risks: • Core infrastructure being vulnerable to security incidents, which would adversely affect the safety and integrity of services. • An increased rate of failure in older critical business IT telephony infrastructure, resulting in unplanned production outages. • Core infrastructure no longer being supported by IT vendors. • Catastrophic failure resulting in non-compliance of Retail Market Procedures. • Being unable to remain agile and deliver new capabilities to the business.
Benefits	The benefits of the project are that it will: • Reduce AGN's exposure to system and security related vulnerabilities and unplanned outages from the failure of critical infrastructure (see Attachment A). • Reduce the risk of non-compliance with Retail Market Procedures (see Attachment A). • Improve the stability of the IT systems. • Provide for core infrastructure to be supported by IT vendors. • Integrate and enhance communications channels. • Enable compliance with latest IT systems with market requirements. • Enable new capabilities to be realised and a greater degree of collaboration to occur through application and services offerings.	Defers capital costs until the subsequent regulatory period.

As outlined in this table, Option 1 offers a number of significant benefits for a relatively low cost, while Option 2 will expose AGN to a number of significant operational and other risks. The risk under Option 2 is, in AGN's view, too high for this option to be considered feasible. Further support for this view can be found in the fact that the age of the telephony infrastructure and vendor release cycles means that deferring the replacement of this infrastructure is not viable. Option 1 has therefore been selected in this case.

5 *Forecast Cost for the Upcoming AAP*

The table below provide a summary of the capital expenditure that is forecast to be incurred in the next AAP under the Infrastructure Renewal project. Further detail on how this forecast has been developed is provided below.

Table 2: Capital expenditure ($'000s $2014/15 – excluding overheads)

	FY 16/17	FY 17/18	FY 18/19	FY 19/20	FY 20/21	**Total**
Infrastructure renewal	512	510	0	0	0	**1,022**

The approach that AGN has used to develop this forecast and its proposed approach to carrying out the work is outlined below:

- The AGN infrastructure environment consists of a number of systems that are tightly integrated. With tightly integrated systems there is a resulting interdependency of associated technologies. Upgrades to applications, infrastructure and associated technologies, are typically not completed in isolation of one another. They instead tend to be run as internal Business & Technology (B&T) projects, which involves the following:
- AGN uses an industry standard B&T Project Methodology, which is managed through formal governance. This B&T Methodology divides the projects into key stages – concept, develop, plan, deliver and close. Each stage consists of key tasks and activities to ensure the consistency and standardisation across projects. The project methodology is outlined in Attachment B.
- The methodology includes an Estimation Tool, to ensure project estimates are standard and consistent. This estimation tool has been used to forecast the work and cost estimates for the application upgrade program of work. This estimation tool utilises historic figures from the current AAP for resource work effort estimates. The work estimates are based on a complexity matrix tool, which uses a series of questions to categorise projects into simple, medium and complex.
- The material and direct labour costs, and applicable planning, design and commissioning charges, are based on historic actual costs of similar projects. Resource Unit Costs (both internal and external) are based on AGN's Project Management Office research, where actual placement costs have been used based on historical project resources and current resourcing rates (FY15).
- When implementing the project, AGN will use a formalised Project Methodology and utilise a combination of internal and external resources (through vendors and trusted recruitment agencies) to deliver the program of work to ensure that services are carried out in a prudent and efficient manner. The Project Methodology is outlined in Attachment B and provides a consistent, standard and quality assured project implementation framework. The Project Management Office (PMO) will provide guidance and governance to the project, ensuring that the work is carried out in a professional manner.

Using this approach, AGN has developed the following forecasts for upgrading the desktop and telephony infrastructure by project stage.

Table 3: Forecast cost of upgrading the desktop infrastructure (real $2014/15 – excluding overheads)

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Next Generation Desktop	
Project Complexity:	Medium	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	**Effort (Days)**	**Estimate Assumptions**
End to End Total	207	$ 340,546
Estimations by Project Stage		
Develop Stage	**Effort (Days)**	**Estimate Assumptions**
Develop Stage Total	31	$ 158,065
Plan Stage	**Effort (Days)**	**Estimate Assumptions**
Plan Stage Total	65	$ 69,606
Deliver Stage	**Effort (Days)**	**Estimate Assumptions**
Deliver Stage Total	103	$ 102,964
Close Stage	**Effort (Days)**	**Estimate Assumptions**
Cost Stage Total	9	$ 9,910

Table 4: Forecast cost of upgrading the telephony infrastructure (real $2014/15 – excluding overheads)

IT & ICT Procurement Estimations Template: B&T Projects		
Project Name:	Unified Communications	
Project Complexity:	Medium	
Project Type:	Upgrade	
Estimations Summary		
Total Project (end to end)	**Effort (Days)**	**Estimate Assumptions**
End to End Total	251	$ 681,253
Estimations by Project Stage		
Develop Stage	**Effort (Days)**	**Estimate Assumptions**
Develop Stage Total	48	$ 478,031
Plan Stage	**Effort (Days)**	**Estimate Assumptions**
Plan Stage Total	76	$ 77,374
Deliver Stage	**Effort (Days)**	**Estimate Assumptions**
Deliver Stage Total	118	$ 115,687
Close Stage	**Effort (Days)**	**Estimate Assumptions**
Cost Stage Total	10	$ 10,161

6 *Consistency with the National Gas Rules*

Consistent with the requirements of rule 79(1)(a) of the National Gas Rules, AGN considers that the capital expenditure required to implement the Infrastructure Renewals project in South Australia is:

- *Prudent* – The expenditure is necessary in order to maintain the integrity of services and comply with regulatory obligations and requirements and is of a nature that a prudent service provider would incur.
- *Efficient* – The proposed project is the most cost effective solution and will enable AGN to maintain its operational efficiency and address the high risks of non-compliance with relevant regulations and legislation, potential customer and business interruptions and corresponding adverse financial and reputation impacts. The expenditure can therefore be considered consistent with the expenditure that a prudent service provider acting efficiently would incur. The manner in which AGN intends to carry out the upgrade (ie, by using a combination of internal and external resources to deliver the program of work and using the Project Management Office (PMO) to provide guidance and governance to the project) can also be considered efficient.
- *Consistent with accepted and good industry practice* – The Infrastructure Renewal project will ensure that AGN continues to operate in line with good industry practice, in terms of having all critical systems up to date and supported by vendors.
- *To achieve the lowest sustainable cost of delivering pipeline services* – The Infrastructure Renewal project is necessary to mitigate the risks associated with operating older versions of the software with the resultant performance and cost implications should these systems fail and is therefore consistent with the objective of achieving the lowest sustainable cost of service delivery.

The proposed capital expenditure is also consistent with rule 79(1)(b), because it is necessary to:

- Maintain and improve the safety of services (79(2)(c)(i)) – Making this investment reduces the risk of failure of the critical systems or security breaches, which could adversely affect the safety of services.
- Maintain the integrity of services (79(2)(c)(ii) – The project reduces the risk the integrity of the network services will be adversely affected by a failure of either of these critical pieces of infrastructure.
- Comply with a regulatory obligation (79(2)(c)(iii)) – The project mitigates the risk of a breach of regulatory obligations if the systems were not available (e.g. Retail Market Procedure requirements for processing timeframes).

Attachment A: Risk Assessment

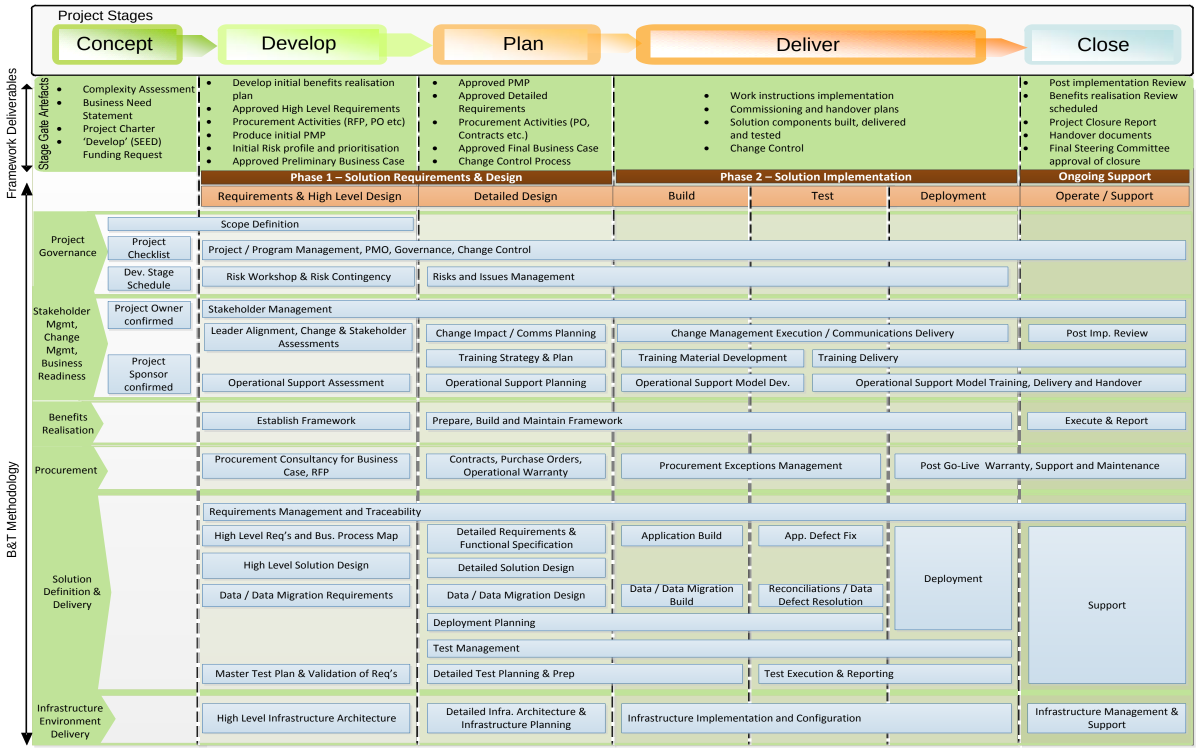
The top panel in the table below sets out the results of the risk assessment assuming the Infrastructure Renewal project is not carried out, while the bottom panel sets out the residual risks if the project is undertaken. Section 3.3 of the Asset Management Plan provides further information on APA's risk assessment framework.

		Health & Safety	Environment	Operational	Customers	Reputation	Compliance	Financial	Total Score of Risk Levels	Cost of Unit of Risk Reduction
Risk Untreated	**Likelihood**	*Possible*	*Unlikely*	*Possible*	*Possible*	*Possible*	*Possible*	*Unlikely*	*Priority 2*	
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Minor*	*Significant*		
	Risk Level	*Moderate*	*Negligible*	*High*	*Moderate*	*Moderate*	*Low*	*Moderate*	***83***	
		14	*04*	*20*	*14*	*14*	*08*	*15*		
Risk Treated	**Likelihood**	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Unlikely*	*Priority 3*	
	Consequence	*Medium*	*Insignificant*	*Significant*	*Medium*	*Medium*	*Minor*	*Significant*		
	Risk Level	*Moderate*	*Negligible*	*Moderate*	*Moderate*	*Moderate*	*Low*	*Moderate*	***71***	
		10	*02*	*15*	*12*	*12*	*05*	*15*		

Priority		**Priority Description**
Priority 1		Any project, where Risk Level of at least one risk area falls into Extreme must be included in Priority 1. These projects should be regarded as non-discretionary, as their justification is to mitigate the risk level that is not acceptable to AGN.
Priority 2		Any project, where Risk Level of at least one risk area falls into High must be included in Priority 2. The non inclusion of these projects may expose AGN, or third party asset owner to potential short and long-term business damage.
Priority 3		Any project, where Risk Level of at least one risk area falls into Moderate must be included in Priority 3. The non inclusion of these projects may affect reliability of assets; as well it may affect operating efficiency and compliance.
Priority 4		Any project, where Risk Level of at least one risk area falls into Low must be included in Priority 4. The non inclusion of these projects may affect opportunity for overall company risk reduction and operating efficiencies.

Attachment B – Methodologies

Project Methodology



BUSINESS CASE – SA83

PROJECT REFERENCE	
Network	AGN - SA
Project No.	SA83
Project Name	Stakeholder Education and Advocacy
Budget Category	Opex
PROJECT APPROVAL	
Prepared By:	Kristin Raman, *Manager Regulatory Policy*
Reviewed By:	Craig de Laine, *Group Manager Regulation*
Approved By:	Ben Wilson, *Chief Executive Officer, Australian Gas Networks*

1 Project Overview

Rationale for Project	This project seeks to position Australian Gas Networks Limited (AGN) to better respond to the changing needs of our gas customers and stakeholders, in alignment with the Australian Energy Regulator's (AER's) Consumer Engagement Guideline for Network Service Providers. This program builds upon the stakeholder engagement program implemented during the current (2011/12 to 2015/16) Access Arrangement (AA) period, and also incorporates new activities designed in response to feedback received during this program. This project comprises five components: Education, Transparency, Advocacy, Engagement and Responsiveness. Each component has been designed having regard to the relevant regulatory requirements and what we heard from our stakeholders during our recent stakeholder engagement program. Further detail on each component is provided in Section 2.
Options Considered	The following options have been considered in order to address the industry changes underway to incorporate stakeholders into decision-making processes: • Option 1: Do nothing. • Option 2: Develop a cost-effective yet comprehensive program of stakeholder education and advocacy, to best address the AER's Consumer Engagement Guideline for Network Service Providers.
Option Selected	Option 2 has been selected because it enables AGN to cost-effectively address the requirements of the AER's Consumer Engagement Guideline.
Estimated Cost	The cost of the proposed program of work in Option 2 is $1.028 million ($2014/15) over the next AA period. These costs are in addition to those incurred in the 2014/15 base year.
Justification of Step Change	This project can be justified as an ongoing step change, because it is in response to an external trigger (in this instance, regulatory change). In addition, this project is in the long-term interests of consumers such that it enables AGN to better understand the needs and preferences of consumers, and to engage them in AGN's decision-making processes.
Consistency with the NGR	*Expanding AGN's stakeholder engagement program is consistent with Rule 91 of* the National Gas Rules because the project:

	• Is such that would be incurred by a prudent service provider acting efficiently; • Is consistent with accepted good industry practice; and • Is necessary to achieve the lowest sustainable cost of providing pipeline services.
Stakeholder Engagement	A key outcome of our stakeholder engagement program was drawing upon stakeholder values and insights to identify four operational themes. This initiative is considered to be consistent with the Include theme as its implementation facilitates the inclusion and involvement of our stakeholders by: • increasing knowledge on who AGN are, what we do and how this impacts the community; • increasing our accountability and accessibility to stakeholders by being more transparent with our performance; • continuing to engage with stakeholders on an ongoing basis and improving the efficiency and quality of this engagement; • ensuring that all customers have a voice and are considered in decision making through advocacy initiatives; • responding to future feedback and changing customer needs in an efficient and timely manner. More information on our stakeholder engagement program and results is provided in Chapter 3 of the Access Arrangement Information (AAI) document.

2 Background

In November 2013, the Australian Energy Regulator (AER) released its Consumer Engagement Guideline for Network Service Providers, placing an expectation on AGN to consult with stakeholders and to describe how this engagement has impacted AA proposals.

AGN responded to this expectation by designing and implementing a stakeholder engagement program for the South Australian network over the 2014/15 year. A key deliverable of this program was an Insights Report from independent consultants Deloitte which outlined 14 key stakeholder insights. Further Information on our stakeholder engagement program is provided in Chapter 3 of this AAI.

Specifically related to this initiative, during our stakeholder engagement program, our stakeholders (including customers) told us that they:

- don't understand AGN's role in the industry or the regulatory model;
- want more communication from AGN via multiple channels;
- believe AGN has a role to play in helping vulnerable customers; and
- trust AGN is meeting its environmental obligations

AGN considered these insights, and how we could improve our service offering to be consistent with the values of our stakeholders. We also considered if changes to our service offering would be prudent spending, ultimately in the long-term interests of our customers.

Consequently, AGN developed this business case in order to provide stakeholders with increased information and transparency they desire, which also has positive implications in terms of safety and engagement effectiveness. Additionally, this business case seeks to ensure all customers have a voice and to continue with effective and efficient engagement.

In order to complete this project, AGN will require X additional internal resources (with responsibility across all jurisdictions) and administrative funds. Further detail is provided on a component-by-component basis in Sections 2.1 through 2.5.

This project is supported by, and references, AGN's stakeholder engagement program and the Australian Energy Regulator's (AER's) Consumer Engagement Guidelines. Further information on these supporting documents are available for review:

- Stakeholder Engagement: Chapter 3, and associated attachments of this AAI.
- AER Consumer Engagement Guideline: https://www.aer.gov.au/node/20998

2.1 Educate

The proposed Education program seeks to address the lack of understanding that customers have with respect to the operation of the natural gas industry, AGN's role in the industry, and the regulatory model. As a result of this program, we will not only increase customer and stakeholder satisfaction, but also increase safety, efficiency and facilitate future engagement.

Currently, the AGN website does not have a library of fact sheets, nor do we liaise with customer groups on an ongoing basis with respect to information requirements. The need for this information has been identified through our stakeholder engagement program, more specifically as a result of:

- **Specific customer insights.** During the workshop phase of the stakeholder engagement program, customers told AGN that they:
    - are confused about the natural gas supply chain and see AGN as being well placed to provide information on this, in particular AGN's role is seen to be more agnostic than the role of the retailer; and
    - have changing expectations about how they engage with AGN, and importantly they seek multiple communication methods for different interactions. One primary method of communication to be deployed to all customers is no longer sufficient.
- **Interviews/meetings with key stakeholders.** During the interview phase of our stakeholder engagement program:
    - the Multicultural Society of South Australia and Uniting Care Wesley Country SA expressed a desire for AGN to work with them to develop a range of fact sheets for distribution to their members (including, but not limited to how to report a gas leak and using gas efficiently); and

- the OTR requested that AGN develop a range of technical fact sheets (including but not limited to meter location specifications and what to expect during mains replacement activities), accessible via the AGN website, to bring our service offering in line with similar utilities such as SA Power Networks.

The benefits to our stakeholders (including customers) of having this information accessible are:

- increased service offering in line with other utilities and stakeholder expectations;
- increased network safety by ensuring that the community is able to access information – for example ensuring tradespeople are aware of their obligations with respect to meter installations and ensuring that those with English as a second language have access to information on reporting gas leaks; and
- increase efficiency – by having information efficiently available to all members of the community and also addressing feedback from our customer workshops in relation to reducing the length of the workshops.

In support of the benefits of Fact Sheets, the OTR stated that

> *"The OTR feel that these fact sheets would increase the effectiveness of our service offering to a range of stakeholders by:*
> - *increasing availability of information and technical requirements to stakeholders (customers, builders and tradespeople), e.g. in relation to meter installations/changeovers and public works in the proximity of the AGN gas infrastructure;*
> - *saving time/increasing efficiency for our stakeholders such as:*
>   - *the OTR, who get numerous calls asking for technical information; and*
>   - *tradespeople and customers who contact the OTR, AGN or APA directly to get this information."*

In addition specifically addressing insights from our stakeholders, implementation of the Educate initiative will also allow AGN to meet the AER's engagement principles as set out Consumer Engagement Guideline. More specifically, the AER state, and AGN agree, that best practice engagement should be accessible and inclusive and service providers should:

> *" - when a matter's complexity is hindering engagement, proactively build consumers' capacity to understand the issues, processes and potential impacts and outcomes of a decision*
> *- ensure that consumers can access sufficient information to understand and assess the substance of all issues relevant to the proposal. This may include the conditional release of confidential information."*

Accessibility and inclusivity was achieved in the current engagement program by undertaking education during the engagement activity, for example allocating time during workshops to explain our role and the regulatory system. The education of stakeholders prior to specific engagement (for example by directing stakeholder to our website) activities will give rise to more effective and efficient engagement. Furthermore, materials developed as part of this initiative can be utilised to facilitate education as required during these activities.

2.1.1. Proposed Action

AGN believes that undertaking activities to educate the public would result in an improvement in customer service (in line with customer values), improvement in safety (through the dissemination of information) and more efficient future engagement.

As part of this initiative, AGN will undertake the following activities:

- partnering with advocacy groups to understand what fact sheets they require to assist them in their role and facilitate distribution to the wider community. For example providing safety fact sheets to the Multicultural Society of South Australia who will then translate and distribute to their members;
- using fact sheets to educate and inform the community on AGN's role and activities, including, but not limited to those suggested by our stakeholders during consultation to date:
    - The OTR:
        - meter location specifications, including proximity requirements;
        - asset ownership, responsibilities and communication issues;
        - what to expect during Mains Replacement activities.
            - checking for leaks;
            - property reinstatement;
            - means/processes of dealing with customers and their queries/complaints;
        - service and installation rules and requirements.
    - Our workshop participants:
        - how the regulatory system works;
        - how retail prices are set.
    - The Multicultural Society of South Australia:
        - reporting gas leaks.
    - Uniting Care Wesley Country South Australia:
        - using gas efficiently.
- respond to any outcomes of our ongoing engagement program (see Section 2.4) relating to increased education;
- refreshed website, with increased access to educational materials (fact sheets, publications) outlining the industry and factors affecting price.

2.1.2. Requirements

This is new work not currently undertaken by the business. In order to implement this project component, AGN requires additional resources to liaise with stakeholders and develop, keep up to date, publish and distribute these materials. In terms of FTEs, AGN will require:

- 0.25 Senior FTE (0.25 at $0.18 Million); and
- 0.25 Junior FTE (0.25 at $0.96 Million).

Given AGN's network footprint, these resources will service multiple jurisdictions. In the final project costing, AGN has made an adjustment to ensure the reported cost is specific to South Australia.

2.2 Transparent

The proposed Transparency initiative seeks to provide more information to stakeholders on key matters such as operational and environmental performance. This program will not only responds to feedback from our stakeholders (customers and other, including the Essential Services Commission of South Australia (ESCOSA)) but will also increase our accountability and accessibility to stakeholders.

Feedback during our stakeholder engagement program identified two key areas where AGN could increase transparency for the betterment of customers and stakeholders: environmental and operational performance, each of which is discussed in further detail below.

2.2.1 Environmental transparency

During our stakeholder engagement program, AGN established two advisory groups, the Retailer Reference Group (AGN RRG), consisting of retailers who utilise the Network and the AGN Reference Group (AGN RG) consistent of a range of customer and community representatives.

The AGN RG told us that we should consult with stakeholders and customers on our environmental credentials and performance. AGN agreed, and included environmental objectives as a topic for consultation.

During the Research Phase, customers told AGN that they "trust" that AGN are meeting their environmental obligations. At the heart of this insight, customers seemed to be unsure of AGN's environmental obligations, and therefore assumed that the regulatory authorities would penalise AGN if obligations were not adhered to.

Additionally, during every customer workshop in the stakeholder engagement program, participants were concerned about AGN's role and the impact of natural gas on the environment, with many unsure of the impact or how that impact compares with other energy sources.

AGN also took the opportunity to engage with Conservation SA, who specifically asked AGN to increase the level of transparency of its environmental performance. Suggestions included reporting Unaccounted for Gas (UAFG) in terms volume with an explanation, providing information on AGN measure's UAFG and updating AGN's environmental policies to ensure they are reflective of today's standards.

2.2.2 Operational transparency

In March 2014 ESCOSA initiated its review of jurisdictional service standards for the next AA period. After consultation with AGN, ESCOSA agreed to delay its decision on service standards, pending the outcome of AGN's stakeholder engagement program. Having regard for ESCOSA's review, AGN's operational performance formed part of our engagement program.

During the engagement program, customers told AGN that despite generally being satisfied with their operational performance there are some areas where AGN could improve.

There was modest support from customers for AGN to respond to gas leaks more quickly, however more specifically it was clear that customers were primarily interested in performance with respect to “emergency “ or “major” leaks, and would like to see AGN responding more quickly to those.

In its review of jurisdictional service standards for AGN, ESCOSA considered the stakeholder engagement work completed by AGN as well as our related submissions.

ESCOSA’s Draft Decision recognises that whilst AGN has been performing strongly, the community wants increased transparency to ensure this strong performance continues. More specifically, the Draft Decision states:

> *“While this review has not identified any areas of service that require improvement through service standards with performance targets, additional transparency around AGN’s performance is required.*
>
> *An enhanced public reporting framework will provide greater assurance to the South Australian community that AGN is managing its network appropriately. It will also provide the necessary data to monitor any material deterioration in current service levels that may require service standards with performance targets in the future”.*

To this effect, ESCOSA’s Final Decision specifically asks AGN to increase its operational reporting requirements.

2.2.3 Proposed Action

Based on the results of our stakeholder engagement program, AGN agrees that we should increase our reporting transparency in order to better reflect the changing information needs of the community.

AGN recognises that the environment is a key concern to our customers and the wider community, and that our current reporting levels are inconsistent with their expectations. This initiative provides AGN with the means to increase transparency with respect to the environment, ensuring that stakeholders are provided with the information they require and increasing AGN’s accountability.

Whilst customer’s indicated they would be willing-to-pay for a quicker response to gas leaks, further review by AGN indicates that this initiative would not be a prudent and efficient investment. Furthermore, we feel that customers were primarily concerned with understanding and ensuring there was a triage system in place whereby more serious leaks were attended to as a priority.

Consistent with this, and keeping in mind that affordability and price are key concerns of our customers, AGN does not propose adjusting crew levels to increase its effectiveness to responding to gas leaks; rather AGN will focus on the transparency of its performance to better allow customers to understand our leak response and other safety mechanism, providing them with comfort over our operations.

AGN agrees with ESCOSA that the community desire further assurance that we are managing our network appropriately. Our submissions to ESCOSA on the matter of jurisdictional service standards reflect this, and we of course intend to adhere to their Final Decision which outlines further reporting requirements.

More specifically, as part of this initiative, AGN will undertake the following activities:

- work with Conservation SA and other stakeholders to test (and where applicable update) our Environmental Policies and other related documentation;
- track and report publicly our environmental and operational performance, having regard for feedback from Conservation SA, ESCOSA and our customers;
- respond to any outcomes of our ongoing engagement program (see Section 2.4) relating to increased transparency; and
- ensure our performance (environmental and operational) is publicly available and easily accessible on our website in order to provide the community with the assurances they desire.

2.2.4 Requirements

This is new work not currently undertaken by the business. In order to implement this project component, AGN requires additional resources to liaise with relevant stakeholders, develop and publish materials as they are developed and periodically report on performance. In terms of FTEs, AGN will require:

- 0.25 Senior FTE (0.25 at $0.18 Million); and
- 0.25 Junior FTE (0.25 at $0.96 Million).

Given AGN's network footprint, these resources will service multiple jurisdictions. In the final project costing, AGN has made an adjustment to ensure the reported cost is specific to South Australia.

2.3 Advocate

The proposed Advocacy program seeks to provide support and a voice for our customers who do not have the means, mechanism and/or expertise to advocate on their on behalf. Whilst this initiative is generally focussed on the vulnerable customer sector, it also has implications for our wider customer base.

Currently, AGN does not play an active role with respect to vulnerable customers, rather we aim to provide cost-efficient services for all, not singling out specific strategies or tariffs for one group. Our relative lack of experience with respect to the vulnerable customer group resulted in it being a key component of our stakeholder engagement program. More specifically, during the research phase of our engagement program we asked customers, retailers and consumer advocacy groups what role we should play with respect to vulnerable customers.

As outlined in the Deloitte Insights report, stakeholders told us that we have a significant role to play in the delivery of natural gas to customers and therefore also have a role to play in supporting vulnerable customers. Moreover, stakeholders provided direction with respect to what AGN's role should be, stakeholders told us that:

- supporting customers that are experiencing financial hardship is not and should not be AGN's core business, and therefore AGN should not seek to support such customers independently, rather we should work with those agencies that are better equipped to support vulnerable customers;
- whilst the advocacy groups and retailers we liaised with during the program were generally not supportive of AGN implementing a specific vulnerable customer tariff, they noted that such mechanisms should be continually reassessed to see if market conditions are such that the introduction of such a tariff would be beneficial;
- we could support vulnerable customers by providing more information on energy efficient appliances (as outlined in 2.1 Educate) and partnering with existing consumer advocacy (welfare) groups and retailers to support their programs;
- further consultation is required to define what a "vulnerable customer" is and how agencies should work together; and
- consumer advocacy groups would appreciate more advocacy from our business.

The Advocacy initiative was not only raised with respect to discussions relating to vulnerable customers, but also our wider customer base. For example, customers in Mount Gambier voiced their concerns that there was a lack of retail competition in the region and wanted to know what AGN could do to help with this situation.

2.2.1. Proposed Action

AGN currently does not have a strategy for supporting vulnerable customers, nor dedicated resources to liaise with consumer advocacy groups and other groups, on specific advocacy matters.

This program seeks to address the needs of our customers by working with consumer advocacy groups, retailers and other stakeholders to develop social strategies and to advocate on the behalf of our customers. More specifically, planned activities include:

- developing a vulnerable customer strategy informed by further engagement activities (see 2.4 Engage) outlining who vulnerable customers are and how we can meaningfully assist them in the future;
- partnering with South Australian consumer advocacy groups and utility providers to develop and participate in a South Australian roundtable (or similar) for vulnerable customers, with a view to continually identifying key issues and strategies across the sector;
- funding to support programs arising from the vulnerable customer roundtable and our vulnerable customer strategy – for example we are currently considering funding options for new efficient appliances;
- working with retailers to enhance their vulnerable customer offering – based on feedback from discussions with retailers; and
- increase public presence to advocate for gas customers on matters arising from our ongoing engagement (see 2.4 Engage) – for example advocating on behalf of the customers in Mount Gambier to promote the National Gas Objective.

2.2.2. Requirements

This is new work not currently undertaken by the business. In order to implement this project component, AGN requires:

- Additional resources to develop and implement a vulnerable customer strategy, establish and participate in a roundtable for vulnerable customers (or similar), liaise with community groups and retailers and advocate where appropriate. In terms of FTEs, AGN will require:
    - 0.25 Senior FTE (0.25 at $0.18 Million); and
    - 0.25 Junior FTE (0.25 at $0.96 Million).
- $0.035 Million per annum to fund the vulnerable customer roundtable and activities/programs stemming from it and our vulnerable customer strategy.

Given AGN's network footprint, these resources will service multiple jurisdictions. In the final project costing, AGN has made an adjustment to ensure the reported cost is specific to South Australia.

2.4. Engage

The proposed Engage program seeks to allow AGN to continue and improve upon stakeholder engagement over the next AA period. This initiative will help AGN to implement the AER's Consumer Engagement Guidelines by engaging with stakeholders in a meaningful, efficient and ongoing manner.

The AER released its Consumer Engagement Guideline in November 2012. This Guideline set out an expectation for AGN to engage with customers and report in their AA how this engagement has directed plans. AGN instigated its first dedicated stakeholder engagement program in July 2014.

The stakeholder engagement program implemented in the lead up to this Submission was robust and fit for purpose, it included utilising internal resources as well as external support to facilitate and report on findings. Additionally, we established two Reference Groups which provided efficient access to a broad range of stakeholders and who were instrumental in the success of the program.

This initiative will allow AGN to continue engaging with stakeholders over the next regulatory period, including informing the 2020/21 to 2024/25 AA proposal, and will also allow AGN to improve engagement having regard to feedback received from stakeholders.

2.4.1 Proposed Action

AGN recognises the importance of engaging with our stakeholders and we are committed to engaging with them on an ongoing basis, not just in the lead up to AA submissions. This commitment is consistent with the AER's Customer Engagement Guideline and with what we heard during our engagement program.

Planned activities include:

- the continuation of the AGN RG and the Retailer Reference Group (RRG).

  - These Groups provided valuable and efficient insight into the stakeholder engagement program.
  - Both Groups expressed an interest in continuing the relationship into the future.
    - The RRG noted that the relationship between retailers and distributers could be improved for the betterment of the customer. To facilitate this AGN is proposing quarterly (as a minimum) meetings to discuss tariff structures, marketing initiatives, market trend, service standards and similar.
    - The AGN RG acknowledge that further consultation is required on specific topics. AGN is proposing quarterly (as a minimum) meetings to discuss specific topics of interests such as the rate of return, vulnerable customers and environmental reporting.
- ongoing small scale market research (surveys)
  - A finding from our stakeholder engagement program was that customers want to be engaged regularly, and more work can be done by AGN to better understand what the priorities and concerns of customers are so as to better plan our activities.
  - AGN is therefore proposing to undertake periodic market research on a much smaller scale than during the recent stakeholder engagement program. The research would focus on obtaining regular feedback on customer's satisfaction with our service performance and engagement strategies.
- dedicated engagement resources to facilitate ad hoc community engagement on major projects as required;
- dedicated resources and external support to facilitate an engagement program to direct and inform the 2020/21 to 2024/25 AA proposal.

2.4.2 Requirements

This is an extension of work undertaken by the business in the current period. In order to implement this project component, AGN requires:

- Additional resources to administer the Reference Groups, manage and develop the stakeholder engagement website, develop, manage and report on the engagement activities and liaise with stakeholders. Whilst AGN completed this work during the current regulatory period, there was no dedicated stakeholder engagement personnel, rather this responsibility fell on existing staff members – something which is not sustainable over the next period. In terms of FTEs, AGN will require:
  - 1 Senior FTE (at $0.18 Million); and
  - 1 Junior FTE (at $0.096 Million).
- $0.025 Million per annum to fund new periodic market research designed to evaluate AGN's performance and understand customer's changing values. This is new work.
- $0.02 Million per annum to fund the continuation of our AGN RG, which was funded by ESCOSA during the current period.

- $0.015 Million per annum to fund travel and meeting costs associated with holding four meetings per annum with the RRG.
- $0.05 Million in 2017/18 and $0.1 Million in 2018/19 to fund external support for engagement activities directing the 2021/22 to 2025/26 AA proposal (costs are consistent with that incurred during the current period).
- $0.03 Million in 2018/19 to fund the costs of running five workshops and developing and implementing an online survey. These costs are additional to what was incurred in the current period, as during the current period AGN was able to utilise and existing (but now ended) digital service agreement to develop the survey and AGN utilised it consultant's premises for three of the five workshops.

In order to avoid double counting of funds, AGN has estimated total project cost to reflect only the funding required in addition to those funds spent in the 2014/15 year. Further detail is provided in Attachment A.

2.5. Respond

The proposed Responsiveness program seeks to provide AGN with the tools and resources necessary to handle the increased customer contact that is forecast to result from an increased external presence through the abovementioned Education, Transparency, Advocacy and Engage programs.

Presently, AGN does not have a dedicated Customer Service Team, with customer enquiries being handled in an ad-hoc manner internally, or directed to either the retailer or to network partner APA Group with respect to technical enquiries. Becoming more visible to our stakeholders through the stakeholder engagement program and making more information available for customers will no doubt lead to an increased level of contact with AGN, something AGN is not currently equipped to handle efficiently.

We are already seeing interaction increase as a result of the recent stakeholder engagement program, for example:

- following on from our stakeholder engagement program, we have received feedback through our new dedicated stakeholder engagement website; and
- during the recent Whyalla/Port Pirie outage, we had one of our AGN RG members directly call the AGN team member responsible for engagement to discuss the situation.

2.5.1. Proposed Action

The stakeholder engagement program highlighted that customers have new expectations about how they are served; one of these expectations is that businesses are responsive and accessible. AGN is proposing a small team to handle an increased level of customer contact.

Additionally, to better serve and engage with our customers, and promote the proposed Digital Strategy, AGN will need to better understand its customers. This deeper level of customer segmentation will allow AGN to better tailor its services.

More specifically, AGN is proposing to establish a small Customer Service Team who would be responsible for:

- developing a customer strategy;
- develop and publish customer service standards;
- respond to customer queries across all platforms (web, telephone, email etc.); and
- respond to and inform the community on major works and or outages.

2.5.2 Requirements

This is new work not currently undertaken by the business. In order to implement this project component, AGN requires additional resources to undertake the key activities outlined in Section 2.5.1. In terms of FTEs, AGN will require:

- 0. 5 Senior FTE (0. 5 at $0.18 Million); and
- 0. 5 Junior FTE (0. 5 at $0.96 Million).

Given AGN's network footprint, these resources will service multiple jurisdictions. In the final project costing, AGN has made an adjustment to ensure the reported cost is specific to South Australia.

3 Risk Assessment

The key risk addressed by this project is AGN's ability to effectively respond to the changing needs and preferences of our customers, and to ensure that AGN is compliant with the AER's Consumer Engagement Guideline.

The key risk for AGN is that without adequate resourcing and funding we will be unable to:

- respond in a timely manner to our stakeholders;
- adequately implement actions arising from our current program; and
- continue engaging with our stakeholders.

This would jeopardise relationships built with customers to date and impede our ability to meaningfully engage with consumers.

4 Key Drivers and Assumptions

The key assumptions and drivers for the project are:

- AGN is committed to continued engagement with stakeholders, consistent with the AER's Consumer Engagement Guideline.
- AGN is committed to implementing feedback from our stakeholders where this feedback is considered to be consistent with their long-term interests.
- AGN will implement a similar, but improved engagement program in the next AA period. Key areas of improvement include completing periodic surveys to better understand stakeholder

values, regular meeting with reference groups across the entire AA period and providing stakeholders with a higher degree of information on which to base their feedback.
- During the next AA period, AGN will take on the cost of running the AGN RG from ESCOSA.
- Increasing transparency is consistent not only with what customers told us during workshops, but also with requests from the OTR and ESCOSA.
- Stakeholders told us that we have a role to pay with respect to vulnerable customers and that this role should focus on further engagement and advocacy.
- Awareness of AGN's brand is increasing as a result of our stakeholder engagement activities and our commitment to increasing transparency and accessibility to our customers. As a result we must position ourselves to be able to respond to the increasing customer feedback.

5 Options

The following two options were considered in relation to this issue:

Option 1 – Do Nothing.

AGN could choose not to implement an expanded and ongoing stakeholder engagement program. Should AGN not respond to these changing needs, we will be unable to build trust with customer and stakeholders, which will ultimately impact our ability to meaningfully engage, sustain and grow our market and to develop long term plans consistent with stakeholder values.

In particular, if this option was selected, AGN would be at risk of:

- Impeding our ability to implement a robust and ongoing stakeholder engagement program, consistent with the AER's Consumer Engagement Guideline.
- Jeopardising relationships with customers as a result of:
    - an inability to respond to enquiries in a timely manner; and
    - an inability to implement suggestions provided by stakeholders – such as the development of Fact Sheets and transparent reporting of performance.
- Preventing AGN from maintaining a clear understanding of consumer preferences, such that costs incurred by AGN may not be in line with stakeholder views and are consequently higher than those necessary to achieve the lowest sustainable cost of providing pipeline services, consistent with Rule 91 of the NGR.

Doing nothing is not viable in the current and forecast regulatory and consumer environment. Customer expectations have changed over recent years and customers expect businesses to:

- provide more information across various channels;
- take an active role in assisting vulnerable customers and other advocacy measures; and
- meaningfully engage on an ongoing basis, including responding in a timely manner to feedback.

The AER also expects business to commit to ongoing and meaningful engagement with stakeholders.

As such, Option 2 is the option selected.

Option 2 – Implementation of an expanded and ongoing stakeholder engagement program.

Details of the stakeholder education and advocacy program are provided in Section 2. AGN considers that this program balances the requirements of the AER's Consumer Engagement Guideline, with cost-effectiveness.

6 Forecast Cost for the Upcoming Regulatory Period

This project requires a step change in operating expenditure totalling $1.028 million over the next AA period. Estimates of project costs have been built up having regard to the additional resources, external support and administrative (including travel and specific initiative funding) costs that will be incurred for each component. Importantly, AGN has ensured there is no double counting by:

- adjusting resourcing costs to reflect the fact that AGN has operations across various states and territories and as such, internal resources will be spread across multiple jurisdictions; and
- only costing stakeholder engagement activities outside of the costs incurred in the 2014/15 year.

Table 1 summarises project costs over the next AA period after these adjustments. A full cost breakdown is provided in Attachment A.

Table 1: Cost Summary.

$'000s (Real 2014/15 – excluding overheads)						
Stakeholder Response	**FY 16/17**	**FY 17/18**	**FY 18/19**	**FY 19/20**	**FY 20/21**	**Total**
Resources [4.5 Full-time equivalent (FTE) staff]	131	131	181	221	131	**793**
External Support [for engagement activities]	0	0	0	60	0	**60**
Administrative	35	35	35	35	35	**175**
Total	**131**	**131**	**181**	**221**	**131**	**1028**

7 Justification of Step Change

As mentioned previously, this project enables AGN to effectively respond to and ensure compliance with an external trigger - the AER's Consumer Engagement Guideline, released in November 2013. The costs forecast by AGN in relation to this project are in addition to the costs already incurred by AGN in the 2014/15 base year.

In addition, this project enables AGN to better serve the long-term interests of consumers by ensuring that consumers are sufficiently educated regarding AGN's role within the industry to the extent that they are able to provide informed opinions on relevant issues, that can then be used by AGN in our planning and decision-making processes.

8 Consistency with the National Gas Rules

In response to the AER's decision to place more emphasis on the voice of gas customers in reviewing the AA of Network Distribution Businesses, AGN has recently conducted extensive customer and stakeholder research to better understand the priorities and concerns of our customers.

We believe that the abovementioned programs are required to implement the AER's Consumer Engagement Guidelines and respond to the insights received from our customers.

Consistent with the requirements of rule 91(1)(a) of the National Gas Rules, AGN considers that the expenditure is:

- *Prudent* – the expenditure is necessary in order to implement the AER's Consumer Engagement Guideline and to offer services that are in line with customer and stakeholder expectations.
- *Efficient* – AGN considers project balances compliance with the AER's Consumer Engagement Guideline with cost-efficiency. The program of work reflects the actual timing of costs incurred and removes double counting for costs incurred in the 2014/15 year. Consistent with feedback from the OTR (outlined earlier), this project will also improve the efficiency for our stakeholders.
- *Consistent with accepted and good industry practice* – Since the release of the AER's Consumer Engagement Guideline, it has become good industry practice to implement effective stakeholder engagement programs. AGN's proposed program of work is consistent with this standard.
- *Necessary to achieve the lowest sustainable cost of delivering pipeline services* – This project enables consumers to be sufficiently informed to play an instrumental role in AGN'S decision-making processes to ensure that expenditure incurred is in line with stakeholder views. This will assist AGN to ensure the achievement of the lowest sustainable cost of delivering pipeline services.

ATTACHMENT A – Detailed Cost Breakdown

Resourcing Cost Assumptions

In order to estimate the cost of implementing this project, AGN was required to make assumptions relating to the value of an FTE and the allocation of resources across our various jurisdictions.

AGN assumes that the FTE cost of a senior resource member is $0.15 Million per annum and the FTE cost of a junior resource is $0.08 Million per annum plus on costs of 20%. These costs are based on an assessment of current salaries within AGN for equivalent personnel.

Jurisdictional Resource Allocation Assumption

AGN is committed to engaging and responding to stakeholders in each region where we operate – that is Victoria, South Australia, New South Wales, Queensland and the Northern Territory. Whilst it is most efficient to have one team of resources operating across all jurisdictions, it is not just for one jurisdiction to pay for the resourcing cost in its entirety.

To account for this, AGN has estimated the total resourcing cost for each component of this project, before applying a cost allocation assumption, resulting in an estimate of the total cost attributable to South Australia.

As this project primarily relates to engaging with and responding to customers, AGN believes that an appropriate allocation should be based on the number of customers served in each region. This gives rise to an allocation factor of 36%.

No Double Counting

AGN undertook a robust and fit-for-purpose engagement program during 2014/15, however as explained earlier, following feedback from our stakeholders and customers we intend to extend and improve upon this program in the next period.

In order to ensure there is no double counting of costs, AGN has removed the costs incurred in 2014/15 from each year of the upcoming AA period estimates for the Engage project component.

Cost Breakdown

Table 2 outlines the cost breakdown for each project component and each cost component.

Table 2: Cost breakdown

	16/17	17/18	18/19	19/20	20/21	Total	Notes
Resources							
Educate							
Senior Resource	45	45	45	45	45	**225**	
Junior Resource	24	24	24	24	24	**120**	
Transparent							
Senior Resource	45	45	45	45	45	**225**	
Junior Resource	24	24	24	24	24	**120**	
Advocate							
Senior Resource	45	45	45	45	45	**225**	
Junior Resource	24	24	24	24	24	**120**	
Engage							
Senior Resource	180	180	180	180	180	**900**	
Junior Resource	96	96	96	96	96	**480**	
Respond							
Senior Resource	90	90	90	90	90	**450**	
Junior Resource	48	48	48	48	48	**240**	
Total Resources	621	621	621	621	621	**3,105**	
Total Resources Attributable to SA Network	**131**	**131**	**181**	**221**	**131**	**793**	Applying the 36% allocation and an adjustment to the engage resources to reflect that a portion are included in the 2014/15 base year
External Support							
Engage							
Regular Surveys							Included in 2014/15 base year cost
Engagement				60		**60**	Partly included in 2014/15 base year cost
Total External Support	**0**	**0**	**0**	**60**	**0**	**60**	
Other							
Advocate							
Funding to support programs identified	35	35	35	35	35	**175**	
Engage							
AGN RG & RRG & Workshop costs						**0**	Included in 2014/15 base year cost
Total Other Costs	**35**	**35**	**35**	**35**	**35**	**175**	
Total Expenditure	**166**	**166**	**216**	**316**	**166**	**1,028**	

Table 3: Cost breakdown by type and component

	16/17	17/18	18/19	19/20	20/21	Total	Notes
By type:							
Resources	131	131	181	221	131	**793**	Total cost reduced to only reflect costs on top of that incurred in 2014/15 for the Engage component
External Support	0	0	0	60	0	**60**	
Other	35	35	35	35	35	**175**	
By component:							
Educate	25	25	25	25	25	**123**	
Transparent	25	25	25	25	25	**123**	
Advocate	60	60	60	60	60	**298**	
Engage	8	8	58	158	8	**240**	Total cost reduced to only reflect costs on top of that incurred in 2014/15
Respond	49	49	49	49	49	**245**	

BUSINESS CASE – SA84

PROJECT REFERENCE	
Network	AGNL – South Australia
Project No.	SA84
Project Name	Development of AGN Digital Capabilities
Budget Category	Capex and Opex
Risk Rating	
Reference Docs	Isobar Digital Consultancy
Confidentiality Claim	Yes (appendices)
PROJECT APPROVAL	
Prepared By:	Jin Singh, *Manager Marketing & Communications*
Reviewed By:	Andrew Staniford, *Chief Operating Officer*
Approved By:	Andrew Staniford, *Chief Operating Officer*

1 PROJECT OVERVIEW

The purpose of this proposal is to outline the funding required to establish a digital platform for Australian Gas Networks (AGN) that will deliver online digital services and communications for customers and stakeholders. A digital specialist consultancy, Isobar have provided a 5 year Road Map (included at the end of this document) to bring AGN's digital services up to date. This Road Map outlines deliverables and justifications for those deliverables and should be read in conjunction with this business case.

A recent stakeholder engagement program run by Deloitte Consultancy found that stakeholders expect more from AGN in terms of our digital presence. In an environment where customers expect information distribution to be swift and practical, our current systems do not provide us with the means to be able to efficiently communicate with the community.

AGN are committed to rectifying this over the next regulatory period by developing and upgrading our digital capabilities, ultimately bringing us in line with other utility businesses, many of whom already have similar digital strategies in place.

The objectives of this project are to:

1. Establish a foundation digital platform that can reliably serve various devices and applications and evolve to meet the needs of the changing technological environment.
2. Make it easier for customers to find and action information about the gas connection process, gas maintenance work and gas emergencies, on the device and time they choose.
3. Improve engagement with various industry partners involved in the gas connection process through the application of digital capabilities.
4. Integrate with existing systems to provide the capabililty to transact online.

This project will deliver a 24/7 customer service channel that can effectively communicate to customers, industry partners and stakeholders, and be an important component of our channels to market – either facilitating connections or processing orders for gas connections with the aim of delivering an improved customer experience and aspeedier gas connection journey.

In order to implement this strategy, we are proposing to:

1. Consolidate AGN's five websites and build a technology platform that will allow us to build our digital capabilities over the next five plus years.

2. Enable web-based enquiries (including near real time) and transactions.
3. Create graphical workflow models and work with partners within the connection process to enable better communication.
4. Build a presence on social media channels to facilitate communications suited to each channel audience.
5. Improve communication with customers relating to unplanned interruptions and expected restoration times.
6. Enable customers to use mobile devices of their choosing to report gas leaks and receive information on gas safety and emergency protocols
7. Develop web reporting systems.
8. Enable digital communications.

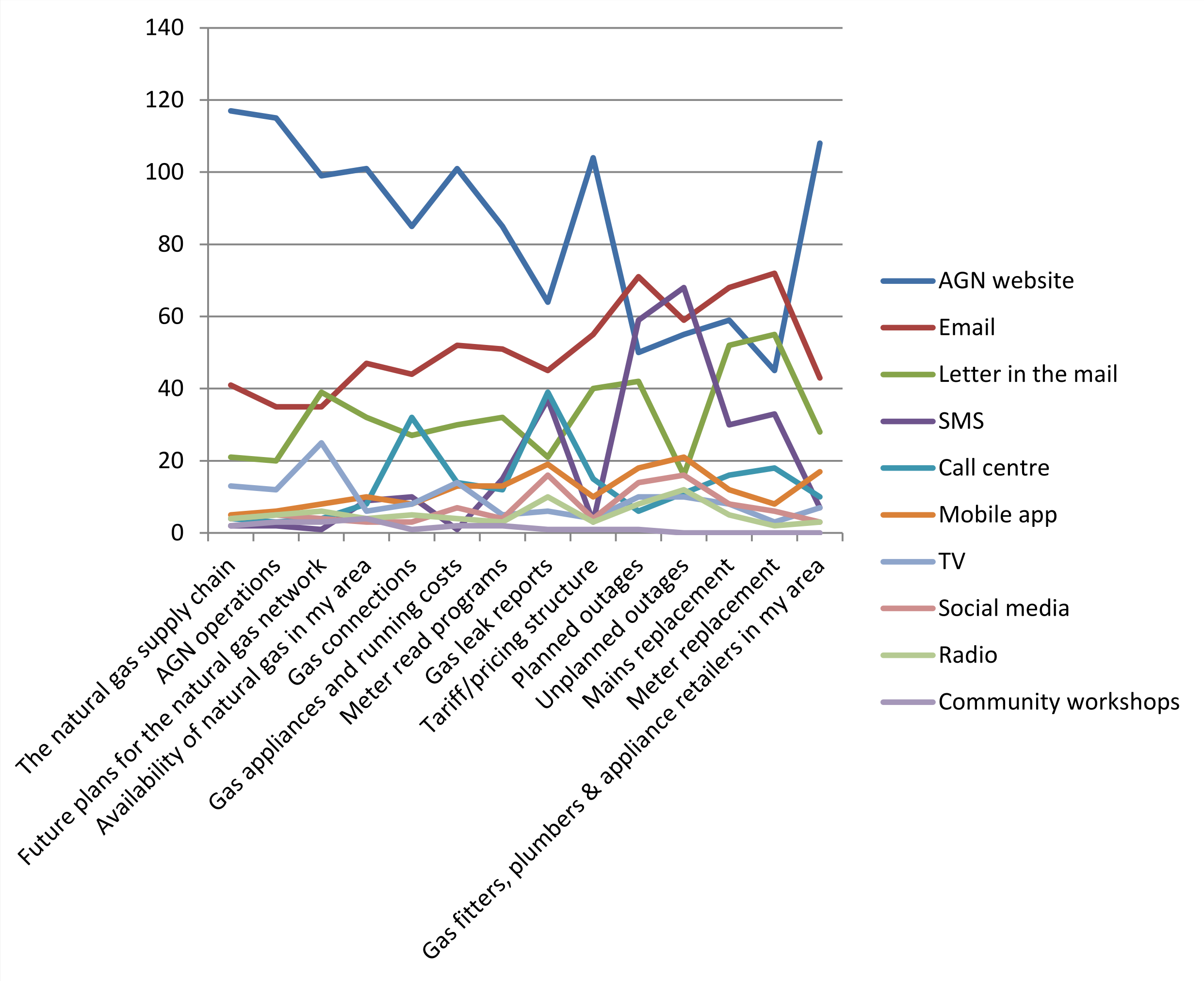
This initiative will allow AGN to meet the future needs of its customers (as reflected in market research and the stakeholder engagement outcomes) by ensuring that AGN has the tools to enable our customers and stakeholders to utilise modern and convenient access to our business processes. This will create improved customer service through a better customer experience and ultimately a more efficient way to transact.

2 BACKGROUND

Digital technology is wide spread and has become part of daily life with more consumers and businesses choosing to seek information, transact, communicate and be entertained through digital channels. The pace of digital advancement has seen many current tools and systems become redundant. Customers expectations for access to digital solutions have also grown over time and are now the expected norm for doing business today.

AGN's stakeholder engagement program was run by Deloitte Consultancy and found that stakeholders want more information about and from AGN, including information about the natural gas supply chain, the regulatory model, the drivers and composition of their natural gas retail bill, technical fact sheets, etc. The stakeholder engagement program findings were clear in term of stakeholder's preferred channel of communication: stakeholders increasingly want to access information through digital channels, particularly where this impacts on their gas supply.

The Deloitte's research findings show that stakeholders choose the AGN website as their preferred method of communication followed by in order: email, letter, sms/text message, call centre, mobile app, TV, social media, radio and lastly community workshops.



The findings from the Stakeholder Engagement program are consistent with findings from market research that has been conducted periodically on behalf of AGN by McGreggor Tan Research and Harrison's Research.

In the latest McGreggor Tan Research dated April 2015, 50% of respondents that recalled AGN's advertisements stated they would go to the internet to get more information. This was followed by 20% "go to a shop", 13% "telephone", 3% other, 18% "don't know" and "wouldn't get more information". 86% from age groups 18-29, 67% from age groups 30-39 and 70% from age groups 40-49 stated they would go to the internet to get more information.

Building digital capabilities will improve customer and stakeholder interactions with AGN by automating processes and bringing information together that currently situated on various AGN owned websites and also stakeholder websites.

2.1 Isobar Digital Agency Engagement

AGN engaged Isobar, a digital specialist agency, to analyse its current capabilities and customer gas connection journey. Isobar's analysis phase included:

- Objective setting workshop and understanding the audiences pain points
- Situational analysis
- Technology Audit: systems integration
- Landscape Review of like businesses in Australia and UK
- Defining the work required: deliver specifications document

Results from the Landscape Review (included in appendicies) found that other similar companies (Jemena, SA Power Networks www.sapowernetworks.com.au , Energy Australia www.energyaustralia.com.au , Northern Gas www.northerngasnetworks.co.uk , Wales and West Utilities www.wwutilities.co.uk for example) in Australia and the UK had digital processes that linked with systems so that customers could access information and transact more readily online. Two key transactions were around gas availability and requesting and tracking a gas connection. The audit also found that AGN had no social media presence while most other like companies did. Lastly, the use of video to explain AGN's role and the gas connection process was also lacking when compared to like organisations.

	Australian Gas Networks	Jemena	Norther Gas Networks	Wales and West Utilities	SA Power Networks	AGL	Origin Energy	Energy Australia
Real Time Content	No	Yes	No	Yes	Yes	Yes	Yes	Yes
YouTube	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Facebook	No	No	Yes	Yes	Yes	Yes	Yes	No
Twitter	No	Yes	Yes	No	Yes	Yes	Yes	Yes
Online Transactions	No	Yes	No	Yes	Yes	Yes	Yes	Yes
Website Video Content	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Chat	No	No	No	No	No	Yes	No	No
Linked-In	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes

The key recommendations from the Technological Audit (full audit document included in appendices) include:

- Consolidating the following five websites: AGNL.com.au; maketheconnection.com.au; natural-gas.com.au; naturalgasintanunda.com.au, stakeholders.agnl.com.au
- Implement a Content Management System that will allow AGN content owners to update and will allow for shared content over several pages.
- Development of new digital customer service channels to better communicate a range of messages from AGN: safety, outages, mains replacement, connection process, gas network area, marketing, corporate, etc
- Development of interfaces between the web and other AGN IT systems to allow improved customer service new connection requests and "Is gas in my street?".
- Campaign and stakeholder data bases be consolidated under one structure.

The user experience testing that Isobar conducted provided some key insights into the high bounce rate results for AGN's websites. Current website bounce rates are shown in the below table. They indicate that customers are not finding the information they require and are leaving the websites within a few seconds and not progressing through to any other pages. Through user testing Isobar determined that customers were confused by the websites and couldn't find key information easily.

Website	Bounce Rate
maketheconnection.com.au	38.31%
natural-gas.com.au	63.29%
agn.com.au	30.71%
stakeholders.agnl.com.au	45.31%

Isobar's research and analysis was the basis of the Digital Roadmap document which is included as an appendix to this business case. Isobar also examined AGN's growth strategy: *increase the number of connections to the gas networks, increase the overall volume of gas used by audience* and to *improve customer service levels*. Delivering an improved website and new digital channels supports AGN's strategy of delivering improved service experience and fits with its vision of being "Customer Focused" as well as delivering on operational improvements.

The Digital Roadmap has three key phases:

- 6+ months: Analysis and recommendation (completed)
- Years 1-2: Establish a foundation platform that meets current needs and industry benchmarks. This platform has the capabilities to be adapted for future needs
- Years 3+: Digitisation of key customer transactions within the connection process. Focus will be on key systems integration and process improvements to allow for digital connection transactions.

Year 1 Outcomes

- Consolidated existing five websites on a new digital platform with focus on ease of connection journey
- Site to be responsive to mobile devices
- Reporting and monitoring structure established
- Optimised website and YouTube channel for search

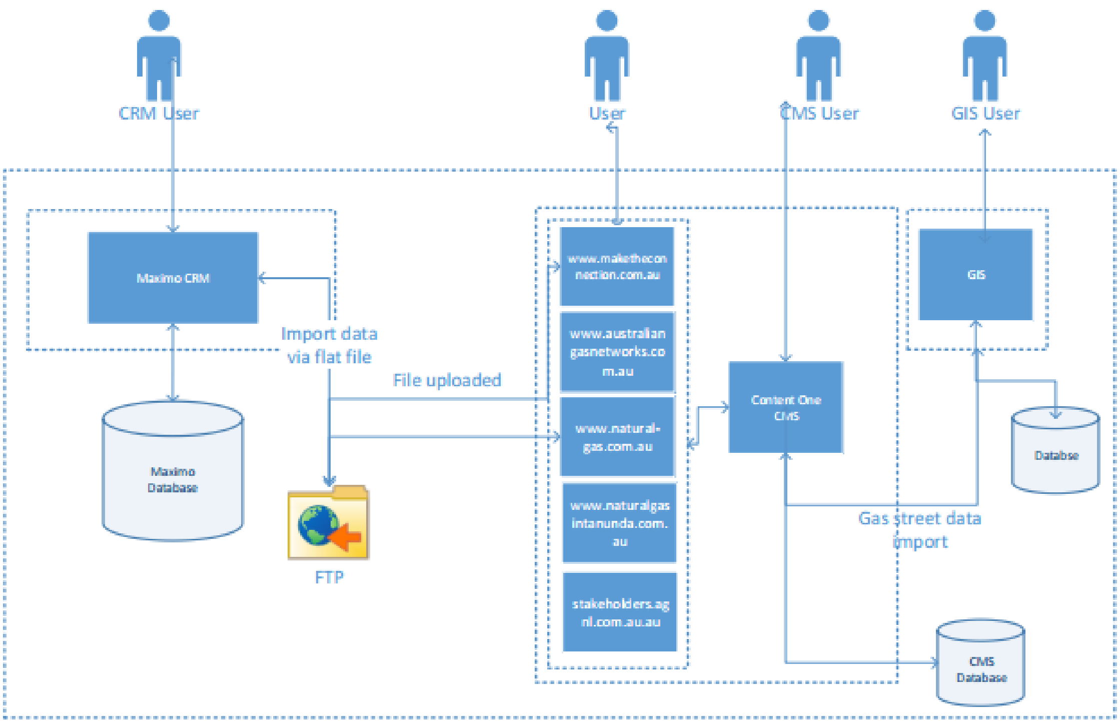
Year 2 Outcomes

- Increased breadth of digital channels to communicate with AGNL's audience
- Greater breadth of content to use throughout AGNL's owned channels
- Increase the number of people AGNL communicate with, especially Home Owners
- Increased service through the introduction of chat functionality

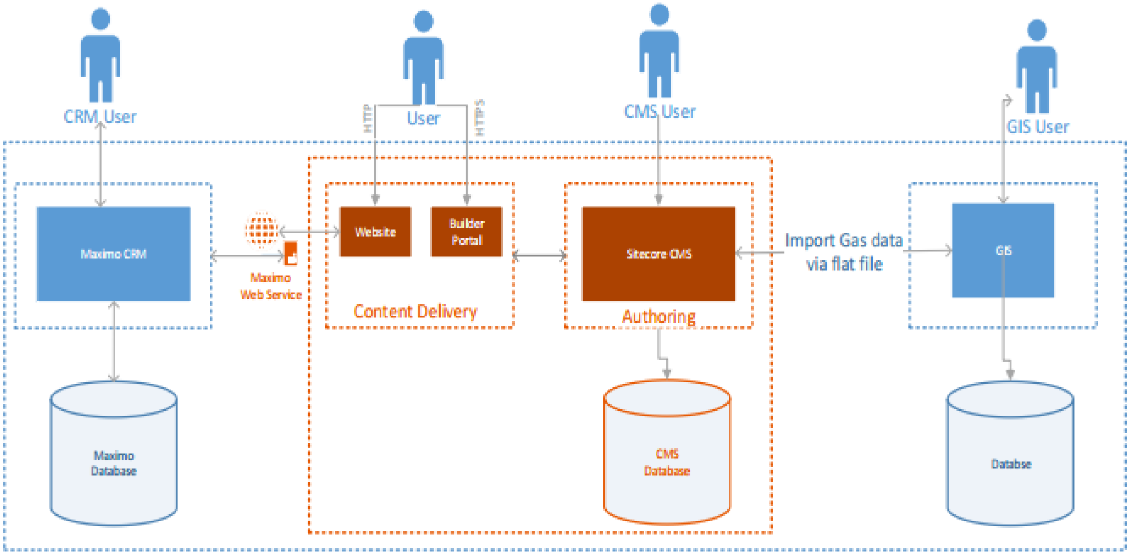
Years 3 to 5 Outcomes

- An in depth understanding of how to make the connection process better for the consumer
- Systems within the connection process that talk to each other and can provide automatic updates to the customers
- A digitised connection experience to help increase communication between stakeholders (householders, businesses, energy retailers, appliance retailers, appliance installers, builders, councils)
- Creation of innovative utilities and products to help users to track the progress of their gas connection request and manage their energy consumption
- Maintaining business as usual activities to continuously improve existing assets

AGNL System Structure



AGNL Future System Structure



3 PROJECT SCOPE

The Development of AGN Digital Capabilities project will deliver a frame work to build a new website and new digital customer services and channels that aren't available today. This will bring AGN in line with other gas distributors in Australia and in the UK. It will also deliver to the particular requirements for South Australia where customers contact gas distributors directly to arrange a new gas inlet connection.

The Development of the AGN Digital Capabilities project will integrate into the Geospatial Information Systems to enable online functionality to make an "Is Gas in My Street?" enquiry and also will integrate into the Maximo EAM system to enable one function to request and track a gas inlet connection.

On completion of this project, the South Australian Networks business will be supported by a new website and digital services and channels.

4 BENEFITS

The key benefits of the Development of AGN Digital Capabilities project are in the following areas:

Consolidated Website

The consolidation of 5 websites will mean that only one website will need to be maintained. This will mean that information will be up to date and consistent, with commensurate efficiencies realised through a simplified support and maintenance structure and improved life cycle development, updating and website management.

This will result in a simplified customer journey which will reduce confusion about AGN as all information will be on one website branded as Australian Gas Networks.

There will also be advantages in terms of search engine optimisation.

Customer Reporting

Website monitoring in terms of search rankings, time on pages, search terms within website, user journey, popular content will be monitored to enable refinements more regularly.

Content Management System (CMS)
The implementation of a user friendly CMS will mean that subject matter experts within each area will be able to update the content of the website without going to a digital agency. This will result in quicker updating of the website. The constraints with the existing system were highlighted in the recent Port Pirie/Whyalla outage (changes could only be made with assistance from the contractor hosting the web site, at times the contractor was available).

Service Delivery Channels
The AGN website will be the key digital service delivery channel. This project will deliver a better layout, a more logical menu structure, better user journey and improved content for our key audiences. It will also be mobile and tablet responsive inline with web user behaviour.

The new website will also be on a flexible digital platform that will enable it to keep up with technological changes.

Digital service delivery will increase with the delivery of new digital customer channels such as Web Chat, email/sms alerts, Twitter and Facebook. These channels will assist AGN communicate to the community in the method they prefer. It will also allow AGN to communicate more regularly and cost efficiently than using traditional paid media channels such as press, tv and radio. AGN will be able to communicate a range of messages to its audiences using social media channels and also email/sms alert registrations. It will be able to help customers with web enquiries in near real time through web chat functionality.

Online Transactions through systems integration
Two key online transactions for customers dealing with AGN include gas availability queries to their area of residence and gas connection requests. Both these transactions would require integration with AGN IT systems. Customers will benefit from being able to conduct these transactions at a time that suits them and also have information about the industry partners that can be involved in the entire process from main to flame (energy retailers, gas appliance retailers, gas appliance installers, plumbers, builders).

Online Tracking of Gas Connection request status
The gas connection process can be complex. This functionality will enable the customer to see what stage their gas connection is at and provide direction for what needs to be done once the AGN inlet has been connected. This will improve customer service.

5 COSTS AND TIMINGS

Initial capability review and development of AGN's digital road map from Isobar costs $75,000. Isobar, a digital specialist agency, were chosen through a tender process. WorldWeb also provided a proposal for the initial scope of work. The Isobar costs were lower than the WorldWeb tender, and the skills and project management structure Isobar demonstrated through their previous projects were deemed superior by an internal AGN panel.

AGN is plannng to invest $1,045,000 in 2015/16 to consolidate existing websites and establishing a content management system that is reliable and flexible enough to meet the requirements of an ever changing digital landscape.

In order to maximise the effectiveness of this investment and deliver better customer service, Isobar have identified a need for a step increase in investment to provide the necessary functionality. The scope for work associated with this incremental spend is addressed in the Isobar Digital Road Map proposal.

Isobar's estimate for the project are detailed below. The cost breakdowns and project details can be found in the Isobar Digital Road Map document which is included at the end of this document.

National	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Opex	$445,000	$965,000	$960,000	$780,000	$780,000	$780,000
Capex	$600,000	$0	$1,200,000	$1,200,000	$0	$0
Total	$1,045,000	$965,000	$2,160,000	$1,980,000	$780,000	$780,000
SA-only	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Opex	$160,200	$347,400	$345,600	$280,800	$280,800	$280,800
Capex	$216,000	$0	$432,000	$432,000	$0	$0
Total	$376,200	$347,400	$777,600	$712,800	$280,800	$280,800

6 *JUSTIFICATION*

Consistent with the requirements of rules 79(1)(a) and 91 of the National Gas Rules, AGNL considers that the expenditure to implement the Development of AGN Digital Capabilities in South Australia is:

- *Prudent* – the expenditure is necessary in order to maintain the integrity of services. The majority of customers surveyed have indicated that they prefer to access information from web-sites. AGN currently has five web-sites. These are perceived by customers as being complex and unwieldy. This is reflected in high bounce rates implying that customers are not locating the information they require easily. This project will establish a more focussed web site, and provide management tools to assess and improve utilisation, to more effectively meet the needs of consumers. It will also provide a platform to use other digital tools as they become available to improve customer service and in particular offer near real time access to gas leak, safety and emergency information. The expenditure is therefore prudent and necessary to maintain the integrity of network services provided by AGN.

- *Efficient* – The recommended project will allow AGNL to meet its objectives of operational efficiency as outlined in its IT Strategic Plan AGN is currently hosting five web-sites. Consolidating these into one web-site will improve operational effectiveness. It will also provide a platform to enable future digital technologies, in line with identified customer preferences. In the longer term this will improve customer service and operational efficiency. A failure to invest in these systems will constrain operational efficiencies able to achieved by AGN.

- *Consistent with accepted and good industry practice* – The landscape review undertaken by Isobar demonstrated that other energy distribution networks have invested in digital assets and tools. The functionality of AGN's current assets is well below those of other leading distributors like SA Power Neworks and Wales and West Utilities. It is also clear that all industries through the wider economy are investing in digital assets. This project will establish digital assets in AGN consistent with those that have been adopted in other energy distribution businesses, and more widely throughout the economy. The proposal is entirely consistent with current accepted and good industry practice.

- *Necessary to achieve the lowest sustainable cost of delivering services* – The world economy is increasingly becoming a digital economy. This is driven by the rising demand by customers for 24/7 access to information. This demand is being fanned by improvements in technology, whereby information can be disseminated quickly to relevant audiences. Companies that do not invest in technology to improve access to information will be increasingly overlooked by digital consumers. It is therefore essential that network providers invest in these assets. This will be necessary to achieve gas connection retention and growth. If investment is not made, it is likely that customers will find the connection process too cumbersome and will be less likely to connect to, or use, natural gas. Any reduction in connection rates because of a failure to provide a digital capability will increase the costs of providing services. To ensure that AGN continues to achieve the lowest cost of delivering sustainable services, it will need to develop digital assets. The use of digital services will also provide other benefits including the provision of improved data for decision making.

Appendices

Appendix A – ISOBAR Proposal (confidential)
Appendix B – Technical Audit (confidential)
Appendix C – Industry Landscape Audit (confidential)
Appendix D – Situational Analysis (confidential)
Appendix E – Digital Vision (confidential)