Firstgas®

GAS TRANSMISSION
Asset Management Plan 2023

AMP Appendices

Appendix A Glossary

Term	Definition
AC power supply	Alternating Current – is an electric current which periodically reverses direction, in contrast to direct current which flows only in one direction.
AMMAT	Asset Management Maturity Assessment Tool – Tool that has been developed to assess the maturity of asset management. This tool consists of a self-assessment questionnaire containing questions and accompanying guidance notes.
ALARP	As Low as Reasonably Practicable – The term is often used for determining a value for acceptable risk. Risk should be reduced to an acceptable level that is as low as possible without requiring excessive levels of investment.
AMP	Asset Management Plan - Document specifying activities and resources, responsibilities and timescales for implementing the asset management strategy and delivering the asset management objectives.
ARR	Asset Replacement and Renewal - It means in relation to capital expenditure, expenditure on assets and in relation to operational expenditure, expenditure on progressive physical deterioration, obsolescence of network assets and preventative replacement programmes.
Asset Grades	Grade 1 - means end of service life, immediate intervention required. Grade 2 - means material deterioration but asset condition still within serviceable life parameters. Grade 3 - means normal deterioration requiring regular monitoring. Grade 4 - means good or as new condition. Grade unknown - means condition unknown or not yet assessed.
BoP	Balance of Plant – It refers to all the supporting components and auxiliary systems of a power plant needed to deliver the energy, other than the generating unit itself.
Capex	Capital Expenditure - The expenditure used to create new or upgrade existing physical assets in the network, as well as Non network assets, e.g. IT or facilities
CCC	Climate Change Commission – a Crown entity established under *the Climate Change Response (Zero Carbon) Amendment Act* to provide independent, evidence-based advice to Government to help New Zealand transition to a low-emissions and climate resilient economy.
CMMS	Computerised Maintenance Management System – Software that helps the organisation plan, track, measure, and optimize everything to do with maintenance on a digital platform.
COO	Chief Operating Officer – Senior executive tasked with over-seeing the day-to-day administrative and operational functions of the business.
CS	Compressor Station - Station that contains gas compression plant.
CP	Cathodic Protection – Technique used to control corrosion of buried steel pipes, casing and vents.
CPI	Consumers Price Index – A measure of changes to the prices for consumer items purchased by New Zealand households giving a measure of inflation.
DCVG	Direct Current Voltage Gradient - A survey technique used for assessing the effectiveness of corrosion protection on buried steel structures.
CRM	Customer Relationship Management – Approach to manage the company's interaction with current and potential customers.
DC	Direct Current – is an electric current that is uni-directional, so the flow of charge is always in the same direction. The direction and amperage of direct currents do not change.

Appendix A Glossary

Term	Definition
DFA	Delegated financial authority – To facilitate the day-to-day operations of the business, the Board has delegated authority to the Chief Executive Officer, the Chief Financial Officer and other persons.
DP	Delivery Point – It means a point where gas is intended to exit the network owned by a person either; to enter a distribution network or for use, conveyance, storage or any other purpose.
DPP	Default Price-Quality Path –The *Gas Transmission Services Default Price-Quality Path Determination 2017* (consolidating all amendments as of 18 December 2018) sets the maximum total allowable revenue that the business can earn each year and standards for the quality of services that the business must meet.
EAM	Enterprise Asset Management – The process of managing the lifecycle pf physical assets to maximize their use; save money; improve quality and efficiency; and safeguard health, safety and the environment.
EHMP	Electrical Hazard Management Plan – It defines the process whereby Firstgas can identify and manage the risk of electrical hazards on its electrically-continuous metal pipelines.
EPR	Earth Potential Rise – Phenomenon that occurs when large amounts of electricity enter the earth.
FDC	Finance During Construction – The FDC allowance and indexed revaluation are calculated for a full year on the opening balance of the system fixed assets regulatory value.
FEED	Front End Engineering Design – Basic engineering which comes after conceptual design or feasibility study.
FIK	Flange Insulation Kit – It protects a flanged joint from the corrosion from static currents (by preventing a metal-to-metal contact among flanges, stud bolts, and baskets).
FY2020	Financial year 2020. Firstgas' financial year is from 1 October to 30 September. FY2020 refers to the period of 1 October 2019 to 30 September 2020
GC	Gas Chromatographs – Instruments that measure the energy quantity of standard volumes of gas.
GDB	Gas Distribution Business – Gas distributors transport gas from the transmission network to smaller users, including domestic consumers.
GIC	Gas Industry Company – Is the co-regulator of the gas industry, working with both the Government and the gas industry to develop outcomes that meet the Government's policy objectives as stated in the *Government Policy Statement* on Gas governance issued in October 2004.
GIS	Geographic Information System – Software designed to present, manipulate and analyse spatial data. A GIS allows the visualisation, questioning, analysis, interpretation, and understanding of spatial data to reveal relationships, patterns, and trends. Key components of a GIS are relational databases, enabling the maintenance and interrogation of infrastructure asset data.
GM	General Manager – Executive who has overall responsibility for managing both revenue and cost elements. A manager in charge of running the main day-to-day business activities of the department.
GMS	Gas Measurement System - Commonly referred to as a gas meter. A gas meter measures the volume of gas passing through it at actual conditions, i.e., at the prevailing temperature and pressure of gas at the gas meter.
GNS	Institute of Geological and Nuclear Sciences – New Zealand's leading provider of earth, geoscience and isotope research and consultancy services.
GTAC	*Gas Transmission Access Code* – The single commercial code for the transmission system that will replace the *Maui Pipeline Operating Code* and the *Vector Transmission Code*.
GTB	Gas Transmission Business – Supplies gas pipeline services as defined under the *Commerce Act 1986*. Firstgas conveys gas to large users of natural gas such as big industrial plants, electricity generators and the gas distribution businesses.

Appendix A Glossary

Term	Definition
HDD	Horizontal Directional Drilling – Method of installing underground pipelines, cables and service conduit through trenchless methods.
HSE	Health and Safety in Employment – Legislation which promulgates number of duties on employers and persons who own or lease equipment to ensure that people at work and people in the vicinity of the place of work are not harmed by the operation of equipment.
HSEQ	Health, Safety, Environment and Quality – Performance will be achieved by an integrated management system and by conditions of sustainability and corporate social responsibility.
ICA	Interconnection Agreement – An agreement between Firstgas and an interconnected party that address the technical, operational and commercial aspects of the interconnection.
ICP	Installation Control Point - The connection point from a customer to the Firstgas network.
ICT	Information and Communications Technology – It refers to all the technology used to handle telecommunications, broadcast media, intelligent building management systems, audio-visual processing and transmission systems and network-based control and monitoring functions.
ILI	In Line Inspection – ILI Tools, sometimes referred to as "intelligent" or "smart" pigs, are used to inspect pipelines for evidence of internal or external corrosion, deformations, laminations, cracks, or other defects.
IMs	Input Methodologies – Documents set by the Commerce Commission that promote certainty for suppliers and consumers in relation to the rules, requirements, and processes applying to the regulation under Part 4 of the *Commerce Act 1986.*
IPS	Invensys Process Systems – It is a major global supplier of systems, software, services and instruments for industrial process automation and asset performance management.
IS	Information Systems – Integrated set of components for collecting, storing, and processing data and for providing information, knowledge, and digital products.
IT	Information Technology - It is the use of any computers, storage, networking and other physical devices, infrastructure and processes to create, process, store, secure and exchange all forms of electronic data.
KGTP	Kapuni Gas Treatment Plant – New Zealand natural gas treatment plant. Kapuni processes natural gas for thousands of industrial, commercial and domestic customers across the North Island.
KPI	Key performance Indicators – Measurable value that demonstrates how effectively a company is achieving key business objectives.
LOS	Line Of Sight – It means that everyone is able to describe how their current work is part of the larger vision and the organisation's core strategies.
LPT	Low Pressure Trip - Installation on Main Line Valve (MLV) actuators to automatically close the MLV when the sensed pipeline pressure falls below the set level. The LPT system is designed to isolate a section of transmission pipeline in the event of an uncontrolled release of gas due to, for instance, a pipeline rupture.
MAOP	Maximum Allowable Operating Pressure – The maximum allowable operating pressure at which a gas system may be operated in accordance with the provisions of the pipelines code or operating standards.
MCS	Control Systems Lifeline - Vendor brand of pressure safety valve.
MLV	Main Line Valve - Valve installed on the main transmission pipelines used to isolate sections of the pipeline for emergency or maintenance purposes.
NRAMS	Non-Routine Activity Management System
NZTA	New Zealand Transport Agency - Their work spans everything from influencing development of the national transport system to promoting road safety, managing the state highway, and licensing drivers and vehicles.

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Term	Definition
OATIS	Open Access Transmission Information System - It is a critical and essential service for open access regimes in order to support the commercial operation of the Vector and Maui gas transmission open access regimes.
OEM	Original Equipment Manufacturer – A company whose goods are used as components in the products of another company, which then sells the finished item to users.
Opex	Operational Expenditure - Ongoing costs directly associated with running the gas transmission system. This includes costs both directly related to the network (e.g. routine and corrective maintenance, service interruptions/incidents, land management) and non-network related expenditure (e.g. network and business support).
OT	Off Take point – means a point where gas is intended to exit the network owned by a person either; to enter a distribution network owned by the same person, or for use, conveyance, storage or any other purpose by any other person.
PIG	Pipeline Inspection Gauge tool – It is a device that is pushed down a pipeline to clean the internals of the pipe and/or measure its wall thickness and integrity.
PIGGING	A method of internally inspecting, cleaning or gauging a high-pressure pipeline, normally while in service to obtain information on pipeline condition.
PIMP	Pipeline Integrity Management Plan – Detailed pipeline operation and maintenance activities to be undertaken to support the safe and reliable operation of the high-pressure pipeline system.
PIMS	Pipeline Integrity Management System – Schedules of maintenance and monitoring activities, record of identified risks and controls, schedule of responsibilities for risks and controls and plan for monitoring control effectiveness.
PLC	Programmable Logic Controllers – Industrial solid-state computer that monitors inputs and outputs and makes logic-based decisions for automated processes or machines.
PJ	Petajoule - Unit of energy equal to 10^{15} Joules or 1,000 TJ.
Planning period	The AMP planning period is the projected 10-year period commencing with the disclosure year following the date on which the AMP is disclosed. The planning period for this AMP is 1 October 2020 to 30 September 2030
PSV	Pressure Safety Valve - Safety device to relieve excess pressure in system to protect system.
RAB	Regulatory Asset Base - The measure of the net value of network and non-network assets used in price regulation.
RCI	Routine and Corrective Maintenance and Inspection
Regulatory period	The period for default/customised price-quality regulation applicable to a GTB as specified in a determination made under section 52P of the *Commerce Act 1986*.
ROAIMS	Rosen Asset Integrity Management Software – Tool that delivers the widest range of analytical capabilities in the pipeline industry in order to maintain and analyse data as part of the integrity management process.
RTE	Response Time to Emergencies - The time from when an emergency is reported to a Firstgas representative until our personnel arrives as the location of the emergency. RTE is a quality standard under the DPP.
SCADA	Supervisory Control And Data Acquisition – A computer system for gathering and analysing real time data.
SCMH	Standard Cubic Meters Per Hour - Unit of gas flow rate.
SIE	Service Interruptions, Incidents and Emergencies – It is one of the key performance indicators at First Gas Group.
SMS	Safety Management Study – Central part of the overall pipeline safety management process and is a prerequisite of maintaining a pipeline certificate of fitness.

Appendix A Glossary

Term	Definition
STA	Standard Threat Assessment – It provides a consistent baseline for assessing individual pipelines. The STA is used as the starting point for assessing each pipeline, based on a standard pipeline design.
T1	Primary location class residential land.
T2	Primary location class high density land.
TACOS	Transmission Access Commercial Operations System – It will replace OATIS and facilitates the implementation of the single gas transmission access code (GTAC).
TJ	Terajoule - Unit of energy equal to 10^{12} Joules.
WBH	Water Bath Heater - A shell and tube heat exchanger utilising to heat gas.

Schedule 11a: Report on forecast capital expenditure

Company Name	**Firstgas Transmission**
AMP Planning Period	**1 October 2023 – 30 September 2033**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

GTBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**	**30 Sep 32**	**30 Sep 33**
9		**11a(i): Expenditure on Assets Forecast**	**$000 (nominal dollars)**										
10		Consumer connection	18	372	382	390	398	405	414	422	430	439	448
11		System growth	2,398	531	545	557	568	579	591	603	615	627	640
12		Asset replacement and renewal	32,178	43,276	27,867	28,842	23,171	25,199	25,289	31,400	35,102	37,497	41,700
13		Asset relocations	195	1,876	2,181	2,227	2,272	2,317	2,363	2,411	3,074	3,135	3,198
14		Reliability, safety and environment:											
15		Quality of supply											
16		Legislative and regulatory											
17		Other Reliability, Safety and Environment	854	743	763	780	795	811	532	542	553	564	576
18		**Total reliability, safety and environment**	854	743	763	780	795	811	532	542	553	564	576
19		**Expenditure on network assets**	35,643	46,798	31,739	32,795	27,204	29,312	29,189	35,378	39,774	42,262	46,561
20		Non-network assets	4,147	4,935	10,425	4,737	8,671	10,105	13,943	12,612	7,189	6,285	6,445
21		**Expenditure on assets**	39,790	51,733	42,164	37,532	35,875	39,417	43,132	47,990	46,963	48,548	53,006
22													
23	*plus*	Cost of financing	670	871	710	632	604	664	726	808	791	818	893
24	*less*	Value of capital contributions	176	1,689	1,963	2,004	2,045	2,085	2,127	2,170	2,766	2,822	2,878
25	*plus*	Value of vested assets											
26		**Capital expenditure forecast**	40,285	50,916	40,911	36,160	34,435	37,996	41,731	46,628	44,987	46,543	51,020
27													
28		Value of Commissioned assets	32,502	42,258	34,441	30,658	29,304	32,198	35,232	39,200	38,361	39,656	43,297
29													
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**	**30 Sep 32**	**30 Sep 33**
32			**$000 (in constant prices)**										
33		Consumer connection	18	350	350	350	350	350	350	350	350	350	350
34		System growth	2,398	500	500	500	500	500	500	500	500	500	500
35		Asset replacement and renewal	32,178	40,749	25,550	25,900	20,400	21,750	21,400	26,050	28,550	29,900	32,600
36		Asset relocations	195	1,767	2,000	2,000	2,000	2,000	2,000	2,000	2,500	2,500	2,500
37		Reliability, safety and environment:											
38		Quality of supply	-	-	-	-	-	-	-	-	-	-	-
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other Reliability, Safety and Environment	854	700	700	700	700	700	450	450	450	450	450
41		**Total reliability, safety and environment**	854	700	700	700	700	700	450	450	450	450	450
42		**Expenditure on network assets**	35,644	44,066	29,100	29,450	23,950	25,300	24,700	29,350	32,350	33,700	36,400
43		Non-network assets	4,147	4,647	9,558	4,254	7,634	8,722	11,798	10,463	5,847	5,012	5,038
44		**Expenditure on assets**	39,791	48,713	38,658	33,704	31,584	34,022	36,498	39,813	38,197	38,712	41,438
45		**Subcomponents of expenditure on assets (where known)**											
46		Research and development											

Schedule 11a: Report on forecast capital expenditure continued

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
55	for year ended	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27	30 Sep 28	30 Sep 29	30 Sep 30	30 Sep 31	30 Sep 32	30 Sep 33
56	**Difference between nominal and constant price forecasts**	$000										
57	Consumer connection	-	22	32	40	48	55	64	72	80	89	98
58	System growth	-	31	45	57	68	79	91	103	115	127	140
59	Asset replacement and renewal	-	2,526	2,317	2,942	2,771	3,449	3,889	5,350	6,552	7,597	9,100
60	Asset relocations	-	110	181	227	272	317	363	411	574	635	698
61	Reliability, safety and environment:											
62	Quality of supply	-	-	-	-	-	-	-	-	-	-	-
63	Legislative and regulatory											
64	Other Reliability, Safety and Environment	(0)	43	63	80	95	111	82	92	103	114	126
65	**Total reliability, safety and environment**	(0)	43	63	80	95	111	82	92	103	114	126
66	**Expenditure on network assets**	(0)	2,732	2,639	3,345	3,254	4,012	4,489	6,028	7,424	8,562	10,161
67	Non-network assets	-	288	867	483	1,037	1,383	2,144	2,149	1,342	1,273	1,406
68	**Expenditure on assets**	(0)	3,020	3,505	3,828	4,291	5,395	6,633	8,177	8,765	9,836	11,568

11a(ii): Consumer Connection

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
70	for year ended	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27	30 Sep 28
71	*Consumer types defined by GTB**	$000 (in constant prices)					
72	General Provision	18	350	350	350	350	350
73							
74							
75							
76							
77	** include additional rows if needed*						
78	**Consumer connection expenditure**	18	350	350	350	350	350
79	*less* Capital contributions funding consumer connection	-	-	-	-	-	-
80	**Consumer connection less capital contributions**	18	350	350	350	350	350

11a(iii): System Growth

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
82	Pipes		500	500	500	500	500
83	Compressor stations						
84	Other stations	2,398					
85	SCADA and communications						
86	Special crossings						
87	**System growth expenditure**	2,398	500	500	500	500	500
88	*less* Capital contributions funding system growth	-	-	-	-	-	-
89	**System growth less capital contributions**	2,398	500	500	500	500	500

Schedule 11a: Report on forecast capital expenditure continued

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
97		for year ended	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27	30 Sep 28
98	**11a(iv): Asset Replacement and Renewal**							
			$000 (in constant prices)					
99		Pipes	12,855	12,750	10,000	13,500	11,500	12,000
100		Compressor stations	9,097	19,286	5,000	5,000	5,000	5,000
101		Other stations	3,212	1,200	1,200	1,200	1,200	1,200
102		SCADA and communications	3,296	3,572	4,700	2,700	700	700
103		Special crossings	-	150	150	150	150	150
104		*Components of stations (where known)*						
105		Main-line valves	494	1,000	2,000	2,000	1,000	1,000
106		Heating system	1,333	2,205	1,000	1,000	600	1,200
107		Odorisation plants	655	-	1,000	-	-	-
108		Coalescers	496	200	-	-	-	-
109		Metering system	510	150	150	150	150	150
110		Cathodic protection	231	236	200	200	100	200
111		Chromatographs	-	-	150	-	-	150
112		**Asset replacement and renewal expenditure**	32,178	40,749	25,550	25,900	20,400	21,750
113	*less*	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
114		**Asset replacement and renewal less capital contributions**	32,178	40,749	25,550	25,900	20,400	21,750
115	**11a(v): Asset Relocations**							
116		**Project or programme***						
117		General Allocation	195	1,767	2,000	2,000	2,000	2,000
118								
119								
120								
121								
122		**include additional rows if needed*						
123		All other asset relocations projects or programmes						
124		**Asset relocations expenditure**	195	1,767	2,000	2,000	2,000	2,000
125	*less*	Capital contributions funding asset relocations	176	1,590	1,800	1,800	1,800	1,800
126		**Asset Relocations less capital contributions**	20	177	200	200	200	200
127	**11a(vi): Quality of Supply**							
128		**Project or programme***						
129								
130								
131								
132								
133								
134		**include additional rows if needed*						
135		All other quality of supply projects or programmes						
136		**Quality of supply expenditure**	-	-	-	-	-	-
137	*less*	Capital contributions funding quality of supply						
138		**Quality of supply less capital contributions**	-	-	-	-	-	-

11a(vii): Legislative and Regulatory

Project or programme*						
** include additional rows if needed*						
All other legislative and regulatory projects or programmes						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environm

for year ended	*Current Year CY* 30 Sep 23	*CY+1* 30 Sep 24	*CY+2* 30 Sep 25	*CY+3* 30 Sep 26	*CY+4* 30 Sep 27	*CY+5* 30 Sep 28
Project or programme*	**$000 (in constant prices)**					
Heater Burner Improvement program	-	700	700	700	700	700
** include additional rows if needed*						
All other reliability, safety and environment projects or programmes	854					
Other reliability, safety and environment total	854	700	700	700	700	700
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	854	700	700	700	700	700

11a(ix): Non-Network Assets

Routine expenditure

Project or programme*	**$000 (in constant prices)**					
ICT Routine Expenditure	2,579	2,752	2,623	2,437	3,973	3,580
Buildings	418	221	5,774	684	2,507	3,966
Motor Vehicles	613	674	761	732	754	777
Plant and Equipment	537	400	400	400	400	400
** include additional rows if needed*						
All other routine expenditure projects or programmes						
Routine expenditure	4,147	4,047	9,558	4,254	7,634	8,722

Atypical expenditure

Project or programme*						
Air Prover Meter certification equipment replacement		600				
** include additional rows if needed*						
All other atypical expenditure projects or programmes						
Atypical expenditure	-	600	-	-	-	-
Non-network assets expenditure	4,147	4,647	9,558	4,254	7,634	8,722

Schedule 11b: Report on forecast operational expenditure

Company Name	**Firstgas Transmission**
AMP Planning Period	**1 October 2023 – 30 September 2033**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.

GTBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref													
7													
8			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
9		for year ended	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**	**30 Sep 32**	**30 Sep 33**
10	**Operational Expenditure Forecast**		**$000 (in nominal dollars)**										
11	Service interruptions, incidents and emergencies		1,340	532	546	557	569	580	592	603	615	628	640
12	Routine and corrective maintenance and inspection		15,139	17,003	17,463	17,830	18,187	18,550	18,921	19,300	19,686	20,079	20,481
13	Asset replacement and renewal		-	-	-	-	-	-	-	-	-	-	-
14	**Network opex**		16,479	17,535	18,009	18,387	18,755	19,130	19,513	19,903	20,301	20,707	21,121
15	System operations		3,314	3,576	3,673	3,750	3,825	3,902	3,980	4,059	4,140	4,223	4,308
16	Network support		6,069	6,858	7,043	7,191	7,335	7,481	7,631	7,784	7,939	8,098	8,260
17	Business support		22,760	26,647	27,366	27,941	28,500	29,069	29,651	30,244	30,849	31,466	32,095
18	Compressor fuel		4,537	8,888	9,128	9,902	10,100	10,908	11,126	11,348	11,575	11,807	12,043
19	Land management and associated activity		1,473	1,850	1,900	1,940	1,979	2,018	2,058	2,100	2,142	2,184	2,228
20	**Non-network opex**		38,153	47,818	49,109	50,723	51,738	53,378	54,446	55,535	56,646	57,778	58,934
21	**Operational expenditure**		54,632	65,353	67,119	69,111	70,493	72,509	73,959	75,438	76,947	78,486	80,055
22			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
23		for year ended	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**	**30 Sep 32**	**30 Sep 33**
24			**$000 (in constant prices)**										
25	Service interruptions, incidents and emergencies		1,340	501	501	501	501	501	501	501	501	501	501
26	Routine and corrective maintenance and inspection		15,139	16,010	16,011	16,011	16,011	16,011	16,011	16,011	16,011	16,011	16,011
27	Asset replacement and renewal		-	-	-	-	-	-	-	-	-	-	-
28	**Network opex**		16,479	16,511	16,512	16,512	16,512	16,512	16,512	16,512	16,512	16,512	16,512
29	System operations		3,314	3,368	3,368	3,368	3,368	3,368	3,368	3,368	3,368	3,368	3,368
30	Network support		6,069	6,457	6,457	6,457	6,457	6,457	6,457	6,457	6,457	6,457	6,457
31	Business support		22,760	25,091	25,091	25,091	25,091	25,091	25,091	25,091	25,091	25,091	25,091
32	Compressor fuel		4,537	8,369	8,369	8,892	8,892	9,415	9,415	9,415	9,415	9,415	9,415
33	Land management and associated activity		1,473	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742
34	**Non-network opex**		38,153	45,027	45,027	45,550	45,550	46,073	46,073	46,073	46,073	46,073	46,073
35	**Operational expenditure**		54,632	61,538	61,539	62,062	62,062	62,585	62,585	62,585	62,585	62,585	62,585
36	**Subcomponents of operational expenditure (where known)**												
37	Research and Development												
38	Insurance												

Schedule 11b: Report on forecast capital expenditure continued

39			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40		for year ended	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**	**30 Sep 32**	**30 Sep 33**
41	**Difference between nominal and real forecasts**		**$000**										
42	Service interruptions, incidents and emergencies		-	31	45	57	68	79	91	103	115	127	140
43	Routine and corrective maintenance and inspection		-	993	1,452	1,819	2,175	2,539	2,910	3,288	3,674	4,068	4,470
44	Asset replacement and renewal		-	-	-	-	-	-	-	-	-	-	-
45	**Network opex**		-	1,024	1,497	1,875	2,243	2,618	3,001	3,391	3,789	4,195	4,609
46	System operations		-	209	305	382	457	534	612	692	773	856	940
47	Network support		-	400	586	733	877	1,024	1,174	1,326	1,482	1,641	1,803
48	Business support		-	1,556	2,275	2,850	3,409	3,979	4,560	5,153	5,758	6,375	7,004
49	Compressor fuel		-	519	759	1,010	1,208	1,493	1,711	1,934	2,161	2,392	2,628
50	Land management and associated activity			108	158	198	237	276	317	358	400	443	486
51	**Non-network opex**		-	2,792	4,083	5,173	6,188	7,306	8,373	9,462	10,573	11,706	12,861
52	**Operational expenditure**		-	3,815	5,580	7,049	8,431	9,924	11,374	12,853	14,362	15,901	17,471

Schedule 12a: Report on asset condition

		Company Name	Firstgas Transmission
		AMP Planning Period	1 October 2023 – 30 September 2033

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a.

sch ref				Asset condition at start of planning period (percentage of units by grade)						
7										
8	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
9	Pipes	Protected steel pipes	km		0.87%	38.31%	60.81%		3	-
10	Pipes	Special crossings	km		-	100.00%			3	-
11	Stations	Compressor stations	No.		11.00%	89.00%			3	-
12	Stations	Offtake point	No.		-	100.00%	-		3	-
13	Stations	Scraper stations	No.			100.00%			3	-
14	Stations	Intake points	No.			100.00%			3	-
15	Stations	Metering stations	No.			100.00%			3	-
16	Compressors	Compressors—turbine driven	No.	50.00%	-	50.00%			3	25%
17	Compressors	Compressors—electric motor driven	No.			100.00%			3	-
18	Compressors	Compressors—reciprocating engine driven	No.	16.67%	25.00%	58.33%			3	
19	Main-line valves	Main line valves manually operated	No.		2.67%	97.33%			3	
20	Main-line valves	Main line valves remotely operated	No.			100.00%			3	
21	Heating systems	Gas-fired heaters	No.	-	1.89%	90.57%	7.55%		3	
22	Heating systems	Electric heaters	No.			100.00%			3	
23	Odorisation plants	Odorisation plants	No.	4.00%	4.00%	92.00%			3	
24	Coalescers	Coalescers	No.			100.00%			3	
25	Metering systems	Meters—ultrasonic	No.	80.00%		20.00%			3	
26	Metering systems	Meters—rotary	No.	23.88%		74.63%	1.49%		3	
27	Metering systems	Meters turbine	No.	13.75%	1.25%	71.25%	13.75%		3	
28	Metering systems	Meters—mass flow	No.	50.00%		50.00%			3	
29	SCADA and communications	Remote terminal units (RTU)	No.	54.95%	-	45.05%	-		3	55%
30	SCADA and communications	Communications terminals	No.	100.00%					3	100%
31	Cathodic protection	Rectifier units	No.		40.00%	60.00%			3	18%
32	Chromatographs	Chromatographs	No.	-	7.00%	93.00%			3	8%

Company Name	**Firstgas Transmission**
AMP Planning Period	**1 October 2023 – 30 September 2033**

SCHEDULE 12b: REPORT ON FORECAST DEMAND

This Schedule requires a forecast of new connections (by consumer type) and gas delivered for the current disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP and the assumptions used in developing the capital expenditure forecast in Schedule S11a [and 11b]

sch ref

7 12b(i): Connections

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**
10	**Consumer types defined by GTB**						
11							
12							
13							
14							
15							
16	** include additional rows if needed*						
17	**Connections total**	-	-	-	-	-	-

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
22	for year ended	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**
23	**12b(ii): Gas conveyed**						
24	Total gas entering the system at injection points	136,590,914	141,482,862	141,070,558	140,661,025	140,254,243	139,850,195
25	Total gas delivered to consumers	135,965,631	140,861,989	140,449,686	140,040,153	139,633,371	139,229,322
26	Total gas used in compressor stations	593,995	593,995	593,995	593,995	593,995	593,995
27	Total gas used in heating systems	104,868	104,868	104,868	104,868	104,868	104,869
28	Total unaccounted for gas	(77,990)	(77,990)	(77,990)	(77,990)	(77,990)	(77,990)
29	**Total gas conveyed**	136,664,493	141,560,852	141,148,549	140,739,015	140,332,233	139,928,186

Schedule 13: Report on asset management maturity

Company Name	**Firstgas Transmission**
AMP Planning Period	**1 October 2023 – 30 September 2033**
Asset Management Standard Applied	**PAS55 Transitioning to ISO55001:2014**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the GTB'S self-assessment of the maturity of its asset management practices.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	Firstgas has a published policy that is available through the document management system, The recent external AMMAT assessment highlighted the need to better communicate the policy internally. The score has been adjusted to align with the external assessment.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	An Asset Management Strategy has been formally developed and incorporated into the AMP. Linkages are in place and evidence is available to demonstrate that, where appropriate, the organization's asset management strategy is consistent with its other organizational policies and strategies.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	Asset Management Strategy has been developed and incorporated into the AMP and covers nearly all asset, asset types and asset systems.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Firstgas has developed an Asset Management Plan for the Transmission Network. This plan covers the transmission network holistically and includes the full asset lifecycle. Plans for critical assets are identified in the AMP. The plan meets the objectives of the Asset Management Policy as well as key performance		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Schedule 13: Report on asset management maturity continued

Company Name	**Firstgas Transmission**
AMP Planning Period	**1 October 2023 – 30 September 2033**
Asset Management Standard Applied	**PAS55 Transitioning to ISO55001:2014**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Firstgas Transmission**
AMP Planning Period	**1 October 2023 – 30 September 2033**
Asset Management Standard Applied	**PAS55 Transitioning to ISO55001:2014**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	A recent gap assessment has highlighted the need to better communicate internally the Asset Management Plan	Aligns to assetivity report	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	Firstgas AMP places responsibility for delivery of the AMP with the Chief Operating Officer (Section 2). The Chief Operating Officer delegates the responsibility of the sections of the AMP through the organisation. These responsibilities and documented in Firstgas position descriptions as		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	Firstgas has arrangements in place to cover the requirements of the delivery, execution and maintenance of the Asset Management Plan. Particulary the project management manual for creation or replacement of assts and maintenance manuals for maintaining existing assets.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Firstgas has comprehensive Emergency response Frameworks and crisis Managment framework to respond to incidents and emergencies. The plans are aligned to the New Zealand Coordinated Incident Management System.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

		Company Name	Firstgas Transmission
		AMP Planning Period	1 October 2023 – 30 September 2033
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)		Asset Management Standard Applied	PAS55 Transitioning to ISO55001:2014

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

	Company Name	Firstgas Transmission
	AMP Planning Period	1 October 2023 – 30 September 2033
	Asset Management Standard Applied	PAS55 Transitioning to ISO55001:2014

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Firstgas has appointed staff who has responsibility for ensuring that the organization's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	Firstgas has a process for determining what resources are required for asset management activities and in most cases these are available but in some instances resources remain insufficient.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	Firstgas communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	N/A. Activities are not outsource.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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	AMP Planning Period	1 October 2023 – 30 September 2033	
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)	Asset Management Standard Applied	PAS55 Transitioning to ISO55001:2014	

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2.5	Firstgas has comprehensive training requirements matrix for operational teams. The external gap analysis recommends that these be extended to include asset management competencies and reflected in the position descriptions		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	3	Firstgas has a training competency training matrix for opertational teams. In addition to Firstgas has a learning Management system for all employess and internal contractors To have visibility of training courses and certificates		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2.5	Firstgas aligns training requirements with established competencies in pipline technical operation and maintenance. A training and development plan exists to ensure that pipeline personnel involved with the operation and maintenance of the asset are appropratly trained. The validation of competency forms part of hte Pipeline Cetificate of Fitness provided by Lloyds Register. The external AMMAT assessment highlights the need to include asset management competencies for staff involved in Asset		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	Firstgas communication plans are primarily focused in external stakeholder. Following the Assetivity gap assessment, the score has been reduced from 3 to 2 to reflect the need for better internal communications internally around the importance of Asset Management and the Asset Management systems.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The Firstgas AMP references the main elements of the asset management system.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	Firstgsas uses Maximo, Meridian, a technical engineering document vault, GIS and Nucleas document control system as primary asset information systems. These systems contain data to be able to support the whole life cycle.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	The external AMMAT assesment has highlighted that this area requires improvement. The current processes rely on individual to manually manage data. The score has been reduced to reflect the assessment.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Firstgas has engaged external consultant to review Maximo functionality and its configuration as one of the primary asset management information system. This concluded that the current configuration and application was appropriate for the businesses needs. In a seperate review conultants were		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	Firstgas has a risk management procedure that is implemented across the business. As a requirement of AS2885 and the certificate of fitness, the assets are risk assessedon a five yearly basis the a Formal safety management study. New assets and modifications to assets are assessed of operational risk through a formalised HAZOP process. Individual risks are managed through a risk item		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3	Where risk assessments identify actions, these are incorporated into the asset information system with an action owner and timeframe for close out. This is monitored by management and audited to enusre proper close out. Where training needs are identified these are updated in		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	3	Firstgas works closely with Worksafe, commerce commission and industry bodies to maintain awreness of its changes in legislation. Regulatory and statutory requirements. The managers for these areas are responsible for communicating the changes to the revelant areas. The appropriate systems will be then		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Processes and procedures are in place to manage ans control implementation of asset management plans. The Project management Mannaul provides the process for design, modification,procurement, construction and commission of assets. Design standards manage the design standards provide control when designs, whilst asset maintenance standards provide management during its life cycle. These are controlled through review cycels		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.

Schedule 13: Report on asset management maturity continued

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Schedule 13: Report on asset management maturity continued

Company Name	**Firstgas Transmission**
AMP Planning Period	**1 October 2023 – 30 September 2033**
Asset Management Standard Applied	**PAS55 Transitioning to ISO55001:2014**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and	3	Firstgas has a document management system to manage controlled documents. This includes processes for review and auditing of documents and processes by interanl auditor to ensure that the processes are maintained.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	The external review noted that Firstgas has a set of performance indicators, which are a mix of leading and lagging indicators. These are monitored weekly. The KPIs are primarily targeted at risk and meet the requriements of ISO55001:2014		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	Firstgas has a document management system to manage controlled documents. This includes processes for review and auditing of documents and processes by interanl auditor to ensure that the processes are maintained.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Firstgas have an established audit procedure and assurance plan to ensure complinace against external and internal requirements. Firstgas engaged Assetivity an external body to it against the requirements under ISO55001:2014.	Refence assetivity	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.

		Company Name	Firstgas Transmission
		AMP Planning Period	1 October 2023 – 30 September 2033
		Asset Management Standard Applied	PAS55 Transitioning to ISO55001:2014

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

		Company Name	Firstgas Transmission
		AMP Planning Period	1 October 2023 – 30 September 2033
		Asset Management Standard Applied	PAS55 Transitioning to ISO55001:2014

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Where poor performance or non conformance is identified, an investigator is assigned to perfrom an investigation of the issue. The aim of the investigation is to determine the root cause and develop actions to remediate the poor performance. The issue is assigned an owner who is repsonsbile to ensure the actions are implemented. An audit is carreid out on completed investigations by the internal auditor to ensure actions have		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	AMMAT external review noted" We believe that the culture within Firstgas is very much one that pursues continuous improvement. This was evident from the many procedures and documents that were reviewed in addition to the discussion with the interviews. Collectively these are in pursuit of improving processes that constitute the Asset Management system"		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2	The external Assetivity gap assessement noted "there is an opportunity for improvement to review the performance of the asset management system as a whole and pursue continuous improvement around asset management objectives aligned to perfromance KPI's		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Schedule 13: Report on asset management maturity continued

Company Name	**Firstgas Transmission**
AMP Planning Period	**1 October 2023 – 30 September 2033**
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

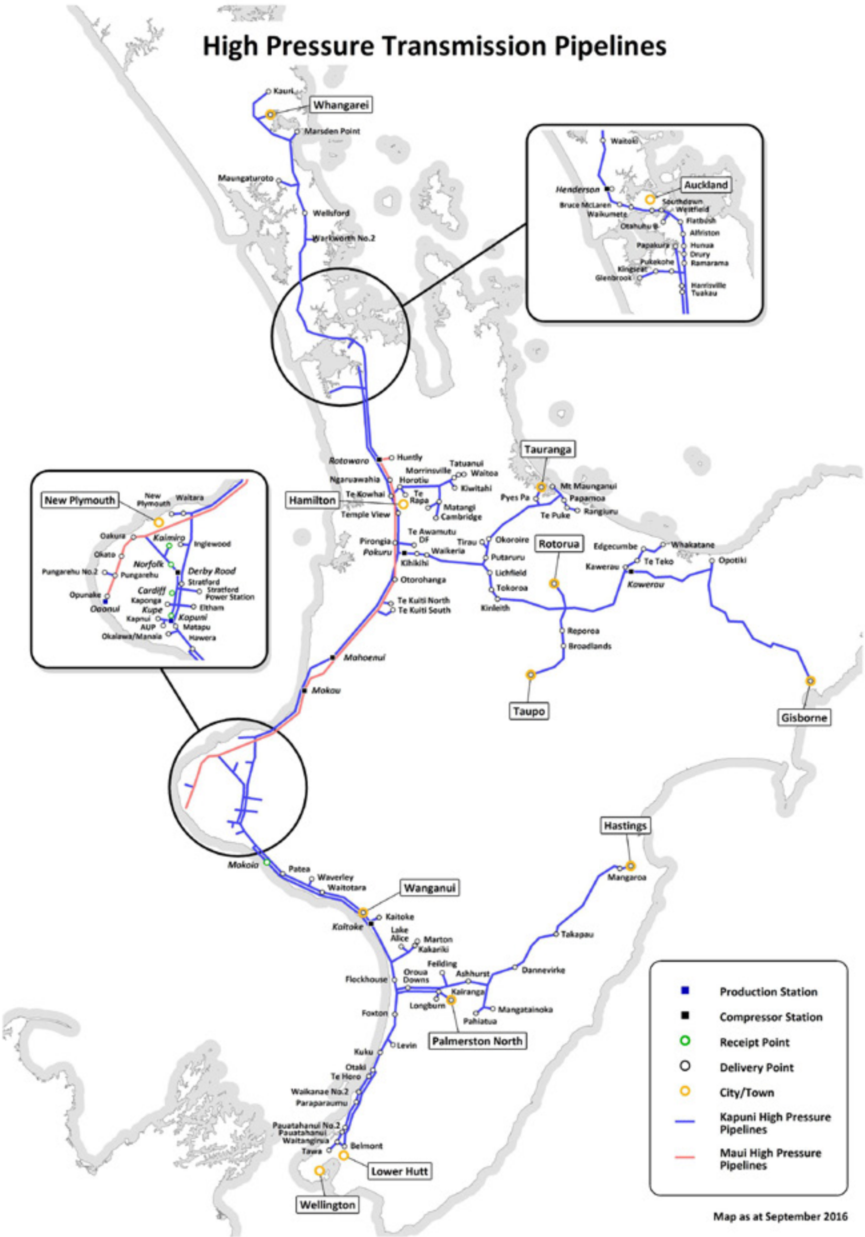
Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

This chapter provides an overview of the gas transmission network.

C.1. Gas Transmission Network

Figure 16 below shows the areas of the North Island served by the gas transmission network.

Figure 16: High pressure gas transmission pipelines



C.1.1. Network Overview

Firstgas owns and operates New Zealand's high pressure gas transmission system consisting of underground pipelines, compressor facilities and above ground stations in the North Island.

The total pipeline length is 2,516 km of which approximately 133km is installed in urban areas and the remainder in rural areas. The pipelines are primarily installed below ground and the nominal bore ranges from 50mm to 850mm diameter. In certain areas sections of pipeline are installed above ground, such as special crossings over major natural or manmade features. Buried pipelines are both externally coated and protected by cathodic protection systems. The pipelines are constructed to recognised standards in accordance with appropriate legislation.

The pipelines connect stations. These contain a range of equipment designed to receive, transmit and deliver gas safely and efficiently to customers. Stations include a variety of asset components and are sited in dedicated securely fenced compounds in safe positions relative to external environmental factors.

The assets were constructed and commissioned in accordance with the appropriate standards applicable at the time. From the mid-1960s to the mid-1980s assets were constructed to codes and standards under US Minimum Federal Safety Standards for Gas Lines - Part 192, US Department of Transport and UK Institute of Petroleum. From the mid-1980s and into the 1990s assets were constructed to the New Zealand gas pipeline code, *NZS 5223* - Code of Practice for High Pressure Gas and Petroleum Liquids Pipelines. In the late 1990s the *AS 2885* Pipelines - Gas and Liquid Petroleum suite of standards was adopted.

Gas is primarily produced in the Taranaki region of New Zealand. Gas is received into the gas transmission system at several receipt points. Most of the pipelines have a Maximum Allowable Operating Pressure (MAOP) of 8,620 kPa with some sections having a MAOP of 7,240 and 6,620 kPa or below. Some short sections of pipeline are limited to a Maximum Operating Pressure (MOP) of 2,000 kPa for operational or safety/risk limiting factors. The pipelines usually operate below MAOP and their pressure will vary due to changing demand levels throughout the day and on a seasonal basis.

The system transmits gas to most of the major towns and cities on the North Island where the pressure is reduced at delivery points before entering downstream gas distribution networks. Some large industrial gas consumers are supplied directly from the transmission system at dedicated delivery points.

C.2. Key Statistics

Table 6 below sets out key statistics for the gas transmission network (at 30 September 2022).

Table 6: Key Statistics

Statistic	Value
System length (km)	2,516Km
Compressor stations	9
Compressor units	20
Delivery points	131

A description of the assets that make up the transmission system is included below with further detail provided in Appendix D.

C.2.1. Asset Categories

Gas transmission networks are made up of several distinct asset types. Categories are used to organise the asset base.

C.2.2. Pipelines

- Special crossings
- Cathodic protection (CP) systems
- Off-pipeline assets (on & off easement)

C.2.3. Main Line Valves

C.2.4. Compressor Stations

- Reciprocating
- Gas turbine
- Electric

C.2.5. Station Components

- Heating systems
- Odorisation plants
- Coalescers and filter/separators
- Metering systems
- SCADA and communications
- Gas chromatographs (GCs)
- PIG launchers and receivers
- Pressure regulators
- Pressure relief valves
- Isolation valves
- Filters
- Station ancillaries
- Critical spares and equipment

The maintenance, inspection, and renewal of assets is discussed in Appendix K.

C.3. Pipelines

High pressure pipelines are constructed from steel with wall thickness and material grades specified by appropriate design codes. Pipeline nominal bore ranges from 50mm to 850 mm. Apart from above ground stations facilities, most pipelines are buried. At some locations, necessitated by geographical features, pipelines are installed above ground using a variety of methods including freely supported spans, attached to road bridges/dams and bespoke supporting structures.

The underground pipelines are coated with various non-conductive materials intended to isolate the pipe metal from the soil and groundwater to prevent corrosion. In the 1960s/1970s coal-tar enamel or polyken tape wrap coatings were used. Pipelines constructed in the 1980s and later have extruded polyethylene coatings ('yellow jacket') and in some cases fusion-bonded epoxy coatings.

Where required by design codes, thicker wall pipe was used, for example road, waterway or railway crossings. A dedicated impressed current corrosion protection (CP) system provides back-up corrosion protection to cover defects in the coatings either from construction, damage, or deterioration over time.

Most pipelines are installed on land over which formal easement rights have been documented with landowners. This ensures Firstgas has full and unimpeded access to the assets. Some pipelines are installed in Council or New Zealand Transport Agency (NZTA) owned roads without the need for an easement as statutory rights of access apply. Facilities on land owned by large customers, are provided for in commercial gas supply agreements.

There are instances where pipelines are buried on land or at facilities owned by others, where Firstgas has no formal access rights. The landowners in these situations are private, government, Iwi, business, or local authorities. In most of these cases the pipelines were constructed prior to the enactment of the Resource Management Act 1991 and are covered by existing statutory rights under the Petroleum Act 1937.

There are several activities or changes in condition that can impact on the pipeline system and may result in a change of the identified risk level. Such changes include:

- Urban encroachment
- Pipeline related incidents
- Emerging pipeline integrity concerns
- Geohazards
- Coating deterioration and corrosion
- Inspections & audits

Remaining life reviews are conducted every ten years on individual pipelines. The review comprises technical workshops facilitated by an independent party. The remaining life review considers the design standard, construction quality, material quality, operational stresses, maintenance history, asset working environment and external stresses, to evaluate current condition and determine a remaining life. The next review is due 2024.

In addition to remaining life reviews, Safety Management Study (SMS) reviews are carried out as part of a rolling programme and conducted at a minimum of every five years.

The SMS process uses a Standard Threat Assessment (STA) to assess threats to the transmission system and apply them to hypothetical base case pipelines in typical rural and urban areas. Any areas of the pipeline that differ from the base case are reviewed, and appropriate mitigating measures determined. Any actions identified as part of the SMS are implemented to either change or improve maintenance routines or renewal programmes. The SMS reports and STA process were independently assessed by Lloyds Register.

Figure 17: Pipeline Age Profile

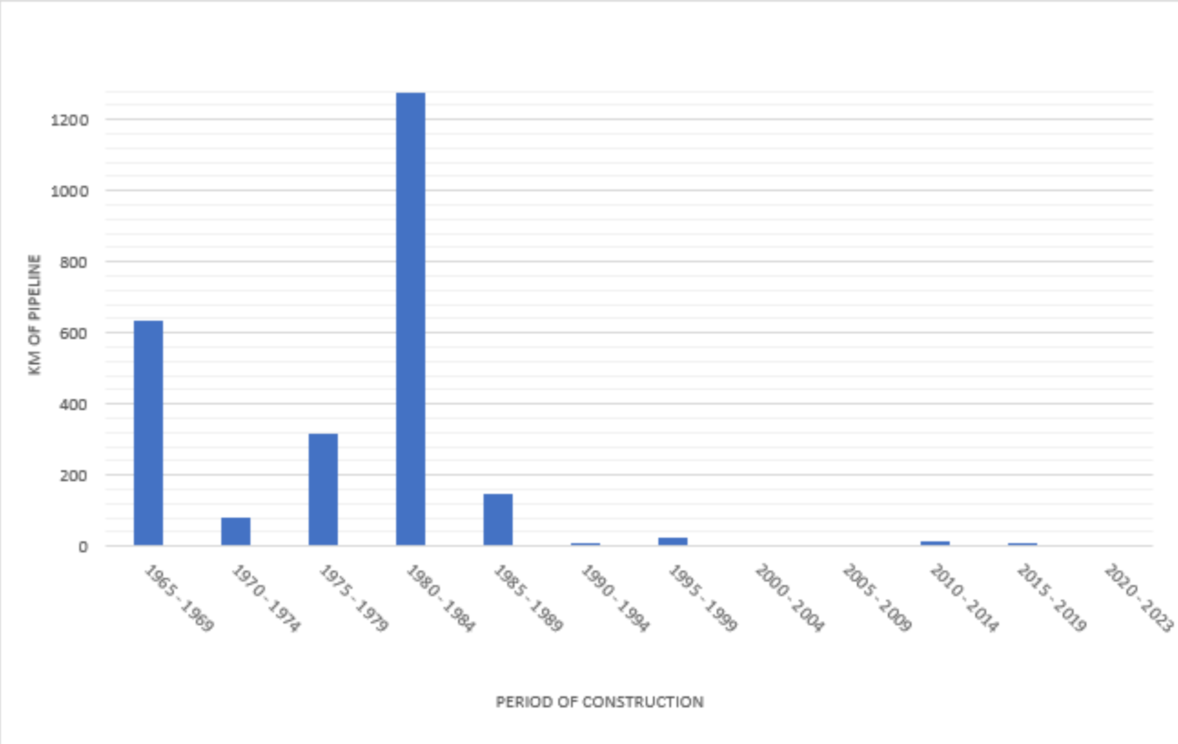


Figure 17 above illustrates that many of the pipelines are over 30 years old. Pipelines are not typically replaced or realigned unless there are specific triggers to do so. However, as the pipeline age profile increases, pipeline coatings can deteriorate, particularly older coal-tar enamel coatings.

Condition based assessments indicate that all pipelines are in reasonable condition and that no excessive deterioration has occurred. However, routine maintenance and inspection of pipelines has revealed some specific instances where remedial work will be required to maintain integrity.

C.3.1. In Line Inspection Programme

Pipeline Pigging

Pigging, in the context of gas transmission lines, refers to the activity using a tool referred to as a 'PIG'. The tool is inserted into the pipeline at dedicated launch and receive locations and allows the maintenance and inspection activity to be completed while maintaining the flow of gas. Gas flow is used to propel the pig through the pipeline.

PIGs can either be used for maintenance cleaning operations or for In Line Inspection (ILI) whereby the PIG tool is fitted with banks of sensors. These 'intelligent' PIGs are used to record pipeline condition data such as wall thickness, or locations of defects. Running this data through an assessment tool is then able to produce pipeline condition reports.

The typical frequency for ILI surveys in rural locations is ten years, and five years in urban locations. An overview of the timing for ILI surveys on the transmission system, as defined in the Pipeline Integrity Management Plan (PIMP) is shown in Table 7 below. The PIMP does not itself present the frequencies; they are included in the Pipeline Condition Monitoring Schedule document.

Table 7: ILI Survey Intervals

LINE	LOCATION	NB (MM)	LENGTH (KM)	INTERVAL
113	Himatangi-Feilding	150	29	10 years
405	Glenbrook Lateral	150	23	10 years
430 [II & III]	Henderson-Maungatapere	150	150	10 years
800	Lichfield-Kaimai SS	150	35	10 years
100	KGTP-Waitangirua	200	255	5 years
200 [III]	Temple View-Papakura	200	96	5 years
200 [I & II]	KGTP-Temple View	200	243	5 years
400	Oaonui – Frankley Road	850	45	10 years
400	Frankley road - Huntly Offtake	750	247	5 years
430[I]	Westfield- Henderson	200	35	5 years
700	Feilding Offtake-Hastings	200	153	10 years
500 [II]	Kinleith-Kawerau	200	103	10 years
500 [I]	Pokuru-Kinleith	300	79	10 years
(600B) 601/605 loop lines	Otaki SS-Belmont	300	17	10 years
(600A) 606/603/604/602 loop lines	Hawera-Kaitoke	300	88	5 years
400N	Rotowaro-Southdown	350	92	5 years
300	Frankley Rd-KGTP	500	47	10 years
715	Stratford-Ahuroa	450	8	10 years
403 (I)	Huntly Power Station	400	9	10 years

Inline inspection is the primary means of monitoring the condition of Firstgas pipelines, and a focus will be to remain up to date with the ILI programme to maintain compliance with the pipeline certifier. In addition to inspection program Firstgas has re-instated the cleaning pigging programme to maintain internal cleanliness of the pipelines and reduce occurrences of contamination.

In-line inspection can be used to monitor a number of integrity risks and provide a comprehensive conditional overview of the pipelines. However, some pipelines configuration prohibits the running of inline inspection tools, for example:

Construction Pipeline bends too small radius to allow tool to navigate around bends
Construction excluded pigging bars at offtakes, which results in risk that tool could become stuck in an offtake
Launcher and receiver facilities were not included in original design
Pipeline diameter too small for intelligent tooling
Excessive pipeline diameter changes.

Firstgas has undertaken an assessment of the currently unpigged lines and prioritised a programme of works to address the issues to allow the pipeline to be piggable, these are:

- 504 Rotorua/Taupo Offtake to Reporoa line
- 702 Foley Road line
- 434 Whangarei lateral
- 435 Kauri lateral
- 421 Te Awamutu North lateral.

Risks and Issues

The ability to proactively identify pipeline defects and repair them prior to failure is essential. ILI tools are the most accurate technology to be able to achieve this. Performing inline inspections allows the integrity risks for each pipeline to be quantified. Indirect inspection methods provide some understanding of external corrosion risks for pipelines; however, a risk remains that certain defect types are not identified.

The integrity risks identified through the monitoring activities are escalated through the existing system for assessment and repair if necessary.

Direct inspection and early detection ensure defects that are outside of code compliance are identified and rectified in a practical fashion. Monitoring the remaining life of pipelines helps ensure all defects contained in a pipeline are monitored for growth and addressed before becoming non-compliant.

Geohazard Risk

Geohazard is the term used for land instability events, such as landslides, floods, erosion or movement of rocks or debris, that has the potential to affect the integrity of transmission pipelines. The impact of geohazards and their relationship to pipeline integrity risk is an area that will always require a focus for Firstgas. Analysis and regular monitoring have identified some high geohazard risk areas and a dedicated programme identifies the individual risks on these sections. The resultant risk is then assessed by the Pipeline Integrity Team.

The Geohazard Management Strategy describes the preferred methods to identify, monitor and mitigate geohazard risk to pipelines.

For this strategy, geohazard is defined as any geological or environmental circumstance or condition that creates the risk of an unplanned and unwanted natural event, with the potential for harm in terms of loss of supply, human injury or ill health, damage to property, the workplace environment, or a combination of these.

Continuous monitoring of all pipelines is carried out to protect and mitigate the effects of these geohazard risks and minimise the potential for pipeline failure using a multi-layered approach of surveys and technology. Using drone technology to improve walking survey efficiency, LiDAR technology to identify ground movement over long distances, up-to-date strain measurement through ILI surveys and regular satellite imagery to locate the presence of geohazards.

Firstgas will reassess current methods used to mitigate geohazards as technological advances are made within the industry.

Geohazard management processes consider the risks posed by activities that can result in a geohazard event, including:

- Earthquake
- Landslides
- Heavy rainfall
- Human activity
- River erosion

All intermediate and high geohazard risks identified are entered into the Firstgas risk system and the pipeline risk and prioritised mitigation actions and solutions assessed. Lower level geohazard risks will be recorded in GIS and monitored over time for deterioration.

An Emergency Response Plan is developed for any high-risk geohazards.

AS2885.1 states requirements for geohazard monitoring and the assessment of risk and evaluation of defects.

Corrosion Protection

Pipeline coatings are the primary corrosion prevention barrier. In order to prevent corrosion, where sections of coating have deteriorated, these sections of coating may need to be replaced or additional rectifier units installed to enhance the CP system.

The data uploaded within the asset integrity management system, along with the ILI and cleaning pigging reports, has enabled greater understanding of pipeline integrity risk. As a result, further investigative monitoring activities aim to achieve a greater understanding of the condition of the pipelines. These activities include:

Emerging Pipeline Integrity Issues

Stress Corrosion Cracking

Stress corrosion cracking (SCC) is a type of environmentally assisted cracking, or the formation of cracking caused by various factors combined with the environment surrounding the pipelines. SCC occurs as a result of a combination between corrosion and tensile stress. Corrosion is related to the susceptibility of the material to the environment, while stresses may be residual, external, or operational.

In addition to the environmental factors that contribute to SCC, a susceptible pipe material is a necessary condition in the development of SCC. The factors that can contribute to material susceptibility are:

- type of manufacturing process
- type of steel
- grade of steel
- quality of the steel (presence of impurities or inclusions)
- steel composition and plastic deformation characteristics
- steel temperature and pipe surface condition.

The critical pipes that are susceptible to SCC in the Firstgas Transmission Network are 100, 200, 300.

A programme is in place to test the 400 line and a management plan under development. However, key components of the Management Plan will require increased excavations and direct inspections of the pipelines.

The outcome of the management plan will update the existing pipeline integrity management plan. Management is likely to be a combination of In-Line-Inspection utilising EMAT tooling and SCC susceptibility assessments.

Selective Seam Weld Corrosion

Selective seam weld Corrosion (SSWC) is an environmentally assisted time dependant threat described as an axially orientated pattern of linear corrosion that is centred on the longitudinal weld seam of welded pipe. A number of factors can be responsible for promoting SSWC, many commensurate with vintage pipe manufacturing and steels.

Firstgas Pre1971 8" pipe is the predominantly affected fleet of pipe. This issue requires further understanding to determine the impact to Firstgas assets, and a management plan for ongoing management of the issue.

Generally management achieved through direct inspection excavation and increased ILI data processing to identify areas that could be susceptible.

Key Projects

- Maintaining intelligent pigging program through the planning period
- Continue with Geohazard Remediation programme through planning period

Typically, unless there is a high risk that needs to be addressed immediately, pipeline work is planned to be completed during the summer months when conditions are more favourable for excavation work, and there is less risk involved with excavations. This however can limit the amount of work undertaken within a year and put a strain on resources to complete the work within specific timeframes.

Pipeline segments with details of individual pipeline numbers, locations, lengths and MAOP rating are included in *Appendix D – Asset Fleets*.

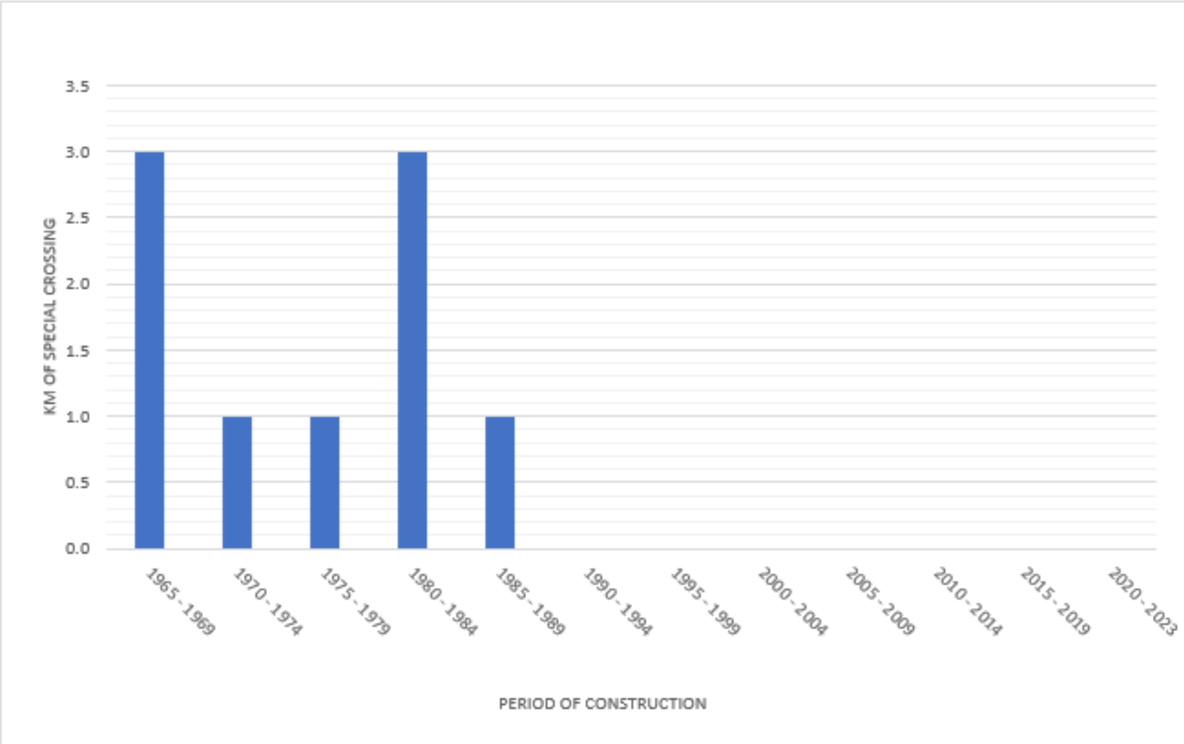
C.4. Special Crossings

Special crossings encompass a variety of crossings installed during pipeline construction. The designs include:

- Aerial self-supporting pipelines
- Pipelines supported by aerial trussed structures
- Buried cased crossings where the pipeline is contained in a concentric steel sleeve
- Pipelines supported on flexible bearings.

Installation of special crossings usually mirror the installation of the associated pipelines.

Figure 18: Special Crossings Age Profile



The self-supporting aerial spans are generally in excellent condition and are routinely inspected and maintained under preventative maintenance plans and issues found and raised either through the maintenance system or prioritised through the risk system.

These are:

- Indications of support degradation and undermining at ground-air interface
- Coating condition
- Nearby threats such as large trees.

The supported spans consist of two elements:

- The pipeline(s) and the support. The pipelines are generally in good condition, however many of the support structures are deteriorating in condition. Access is one of the issues when carrying out inspections and remedial works. Notable examples of this class are Tuakau Pipe Bridge (400L), Arapuni Dam and Headrace Bridge crossings (both 500L).

- The Engineered Crossings – above grade, includes any special crossing that has been modified, adapted, or significantly reworked and requires a routine monitoring plan or specialised surveillance. This includes Gibbs Fault (100L and 605L), Pukearuhe (400L), Tumunui (503L). All are currently in very good condition although some minor earthworks and retaining may be required at Pukearuhe.

Cased Crossings are no longer considered to be best practice due to the difficulty in assessing the condition of the carrier line, particularly unpigged lines. They are also susceptible to filling with water and silt that can cause CP shorts and accelerated corrosion. They are archaic but still required for Railway Crossings as stated in the applicable railway design and operating codes. It can only be stated, with some reservation, that carrier pipes in cased crossings on pigged pipelines are believed to be in fit-for-service condition. When circumstances allow casings would be removed. Ironically, compromised casings are under roads and railways and are therefore more complicated to dig up and repair. Grade 2 would be a realistic condition for the fleet.

Condition

Programmed condition assessments and surveys of pipelines at special crossings (including support structures, ground/air interfaces, access platforms and pipe supports/brackets) is managed through the Computerised Maintenance Management System (CMMS). Recommendations will then be assessed and incorporated into the AMP work plans as required.

General condition reasonable, no change to management approach planned.

Figure 19: Pipelines at Gibbs Fault near Wellington

Risks and Issues

The biggest issue with special crossings is accessibility for inspection is the key issue e.g. Tuakau river crossing and the Arapuni dam. This may be due to the crossing being in a road reserve, or the structure access is restricted due to height, or traversing over water. If works are planned on these structures, for either maintenance or inspection, considerable planning and notification may be required with all stakeholders including landowners, Waka Kotahi, local and/or regional councils.

Key Projects

- Remediation of the access track to Gibbs fault
- Tuakau Bridge Crossing condition assessment

C.5. CATHODIC PROTECTION SYSTEMS

In addition to their external coating, pipelines are connected to an impressed current and CP system. This provides secondary protection against corrosion at coating breaches by holding the pipeline at a negative voltage relative to the ground.

The CP system comprises the following assets:

- CP power supply (rectifier)
- Test points to enable monitoring of CP levels
- Electrical resistance probes for monitoring corrosion rates at critical locations
- Insulating joints to electrically isolate the cathodic protected pipe.

The rectifier sites are spread over the pipeline network and have been selected to ensure full pipeline coverage. Power outages at a single rectifier can generally be compensated for by the rectifiers either side of it. Most CP rectifiers are monitored from the Bell Block office via the intelligent power supply system. Rectifier outages are quickly identified and remediated.

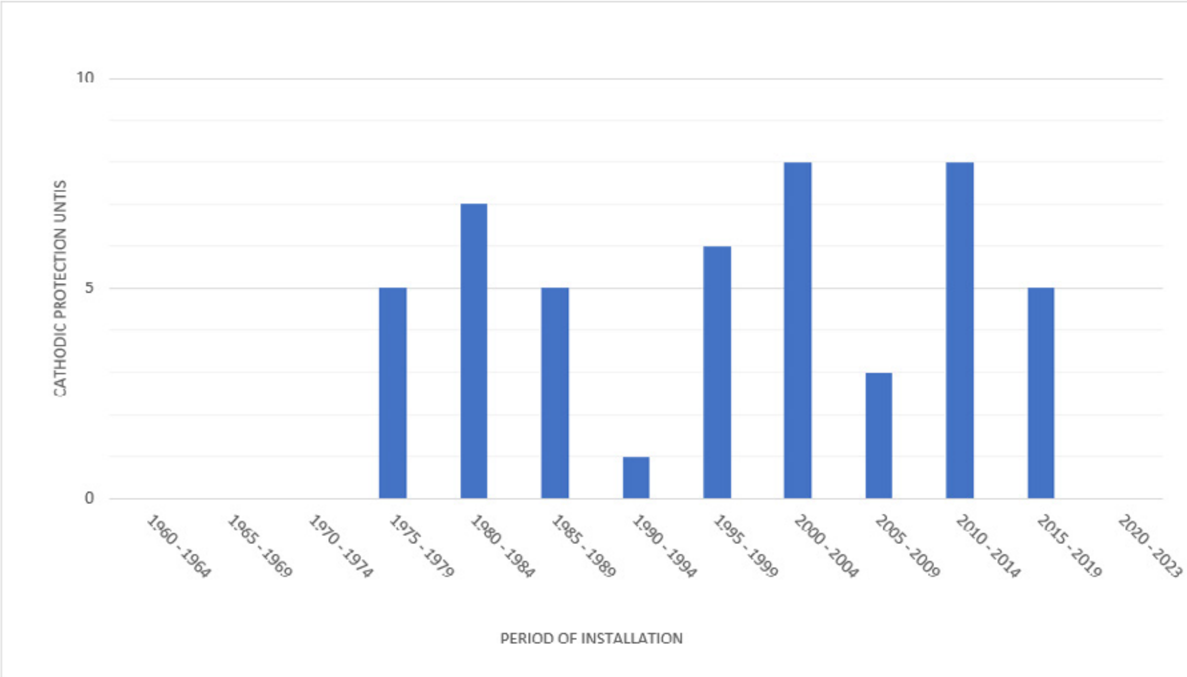
A rectifier site consists of the following items of equipment:

- A rectifier unit that draws low-voltage DC current from the pipeline
- A buried anode bed that discharges current to ground
- An external ac power supply (generally a metered supply from an electricity distribution network)
- Cables connecting the rectifier, anode bed and pipeline
- The IPS remote control and monitoring unit.

Rectifier units are generally pole or ground mounted and secured in cabinets to prevent interference by the public.

Insulating joints, including Monolithic Insulation Joints and Flange Insulation Kits (FIKs) are indirectly monitored via CP system performance testing. Testing of insulating joints is included in investigations into loss of protection. Most insulating joints are located at stations. A provisional amount is included in the forecast for replacement of failed insulating joints.

Figure 20: Rectifier Age Profile



Condition

A significant number of the rectifiers have exceeded their design life, and in some cases have been retro fitted to ensure continued operation and compliance with current electrical regulations.

Anode beds deteriorate with time, as they discharge current into the ground. Under normal operation rectifier output current will decrease and voltage increase as the anodes are consumed. Utilising this trend, it can determine which anode beds are reaching the end of their life.

Land use changes are prompting change in the CP protection requirements that requires additional CP test points, in addition to relocating CP rectifiers in response to the urbanisation.

Risks and Issues

CP provides secondary protection to the pipeline and is critical to maintaining pipeline integrity and is a requirement under AS2885. Condition assessments allow for the replacement of rectifiers to be managed through a staged replacement programme. Replacements are prioritised on the condition and performance of the assets.

New test points are required on the network to meet the maximum recommended spacing in T1 and T2 class locations and the forecast includes provision for this. CP system current demand is increasing as the pipeline coating deteriorates with time. On some pipeline sections, the current demand will increase to an amount where additional rectifiers are required between the existing rectifiers.

Key Projects

There are no major projects planned under CP systems as the work would be considered business as usual replacements or upgrades.

- Anode bed replacements
- CP test points
- Relocation rectifiers
- Additional test points in urbanized areas – requires ongoing programme
- Rectifier monitoring upgrades across multiple sites
- Bond monitoring– multiple sites. Investigation required
- ER Probe installations – ongoing programme FY23 onwards. Requires detailed plan
- Insulating joint replacement.

Figure 21: Typical pole mounted rectifier unit

C.6. Off-Pipeline Assets (On and Off Easement)

Transmission pipelines are managed through easements, however, in some areas there may be additional assets that are not located within the easement. These are referred to as off-pipeline assets and are predominantly civil construction type assets. Depending on construction, they may require routine maintenance plans to ensure they are maintained to a suitable standard. These assets may include the following:

- Retired land blocks
- Access tracks and culverts
- Crib or retaining walls
- Fencing and drainage
- Ground water monitoring equipment
- Land movement monitoring equipment

Some of the assets would have been installed during construction, as part of the pipeline project. However, during the life of the pipeline, additional assets may have been installed in response to specific events.

Firstgas has invested in survey technology that will enable for efficient recording of off-pipeline assets. The field application allows for the position to be surveyed and photos attached to the location that is then uploaded to the GIS system, creating a record of the asset.

Figure 22: Typical Off-pipeline Assets

Risks and Issues

Lack of formal construction data and recording of maintenance practices on the off-pipeline assets has resulted in an ad-hoc approach. This does not align with the current asset management approach. With the introduction of the survey equipment, off pipeline assets can be recorded, and appropriate maintenance and inspection regimes can be established.

Key Projects

The introduction of the survey application allows for the field staff to record the location and photos of the off-pipeline assets accurately and efficiently. On-going maintenance requirements can then be established for the assets. This project will be on-going.

C.7. Main Line Valves

Main line valves (MLVs) are designed to automatically isolate pipeline sections when pipeline failure occurs. MLVs are positioned at maximum intervals of 32km throughout the length of the gas transmission system with exception to the Auckland metropolitan area. In Auckland, MLVs are nominally spaced at 13km intervals due to the higher consequence of pipeline failures. The MLV fleet consists of 148 Main line valves, which comprise primarily of two main actuation types, linear and rotary. The majority of MLVs are underground with their associated actuators installed above ground. The drive to operate an underground valve is transmitted mechanically via an extended shaft.

An MLV unit includes the following main equipment items:

- Main line valve
- Bypass valves and pipe work
- Valve actuator that can be operated by local low-pressure trip (LPT), remote control or manual hand wheel with an associated gearbox.

Where a MLV is installed with remote operation facilities there will also be a remote terminal unit (RTU) installed for SCADA communications.

MLVs operate in one of the following modes:

- Remotely operated via the SCADA system. If the actuator fails to operate the valves can be operated manually using a hand pump

- Automatically operated via a local low-pressure trip (LPT) unit which detects a line break. If automatic operation fails, the valves can be operated manually using a hand pump
- Manually operated either by a gas/hydraulic or electric operator locally or via a hand wheel.

A typical NB 400mm manually operated MLV fitted with a gas over oil actuator is shown in Figure 23 below.

Figure 23: Typical Manually Operated MLV

Electric power (where installed) for the control and communication systems comes from local mains supply. Otherwise, power is generated locally by solar power or wind generator backed up by batteries. If the electrical supply should fail the automatic LTP remains active and manual hand pump operation is available.

MLVs are typically incorporated in the following stations:

- Compressor stations
- Delivery points
- Receipt points
- PIG launcher and receiver stations
- Dedicated MLV stations

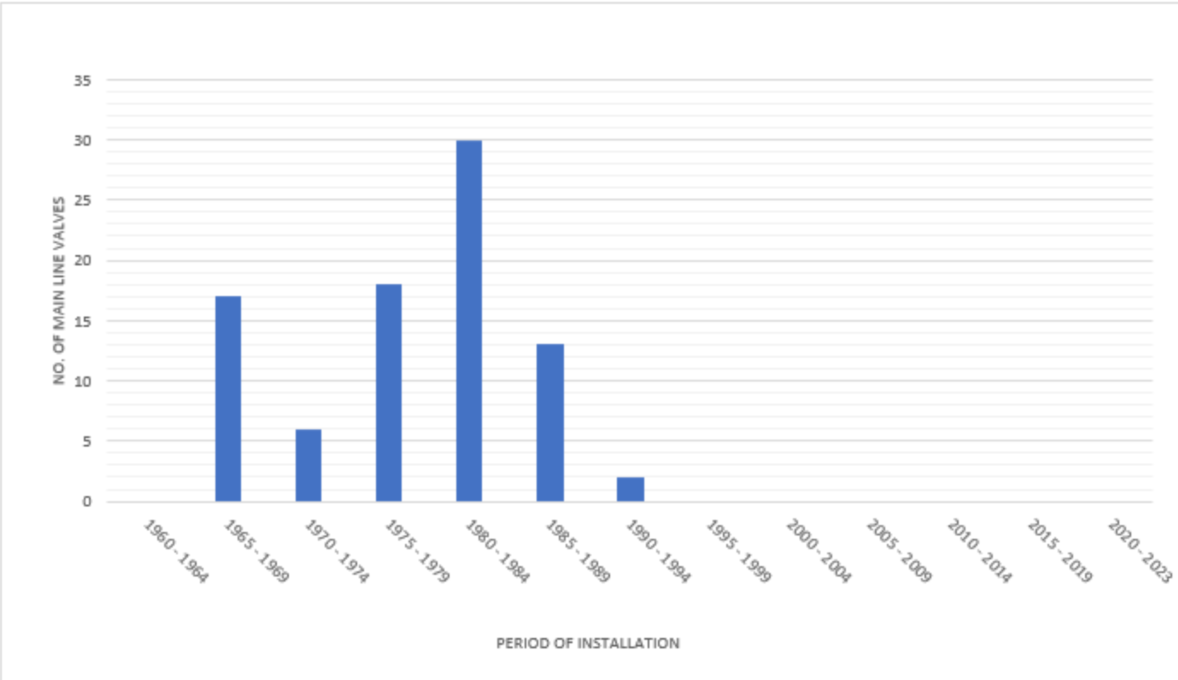
Linear actuators actuate the gate valves and rotary actuators are used to operate the ball valve types. Both systems use pressurised gas to provide hydraulic energy to operate the system. In some locations, manual hand valves are used to provide isolation to the pipeline if required.

MLVs are predominantly installed with either Biffi or Shafer actuators with different designs dependent on MLV design, size and characteristics.

MLV's were installed during construction of the pipelines with no active replacement programmes since the installation other than for the remote actuation control system installation. Retrospective remote actuation of strategic MLV's has updated the control systems to be more current and in line with the *AS2885* standard.

The condition of the fleet of MLV actuators and associated control systems may be considered as poor. The Firstgas Schafer and Biffi systems are generally considered to be obsolete with stock lines of spare parts being increasingly hard or impossible to find. Hard parts that are not available as stock are required to be manufactured through a management of change process. Soft parts are significantly diminished, the MOC process is being used to enable the use of alternative components.

Figure ??: Main Line Valves Age Profile



Risks and Issues

Some of the MLV's are experiencing age related functional and maintainability issues. Issues may include:

- Inadequate valve sealing capability
- Historical poor coating performance of above ground components
- Components becoming obsolete
- Typically valves are welded in place, making replacement complex and costly.

At the time of construction MLV's were generally installed in rural areas, over time land use changes has resulted in MLV's being in urban areas. Typically, the MLV's utilise system gas to operate, which is then vented to atmosphere. This urbanisation is affecting the ability to safety operate the MLVs.

Key Projects

- Finalising of MLV strategy and associated management plan

C.8. Compressor Stations

Gas is often transported over long distances, which causes gas pressure to decrease due to frictional losses in the pipeline. Pressure is increased by compressors to ensure that the required gas pressure and quantity is delivered to the extremities of the system. Compressor stations are situated at strategic locations in dedicated securely fenced compounds.

The network configuration for compression requirements for the network has changed significantly over time. Over the last few years, Firstgas has developed a network optimisation and compression strategy to optimise the compression needs on the network for now and in the future.

A list of the compressor units is included in *Appendix D – Asset Fleets*.

C.8.1. Network Compression Optimisation

The current transmission system utilises a number of compression stations to ensure that the pressure in the transmission network is maintained at appropriate pressures. The operating conditions at the time of construction is significantly different to what is currently being experienced. These compressor stations are now presenting issues with reliability, efficiency, and emissions. Firstgas has set several strategic objectives for the compression optimisation and replacement programme. These primarily consist of replacing the existing assets with right sized equipment, ensuring security of supply on the network, reducing the emissions, and total compression requirements where practicable.

Firstgas Compressor strategic objectives are outlined below:

- Replace the current compression fleet with right sized modern compressors – The current fleet suffers from poor reliability and poor utilisation. Replacing these units with right sized modern units, with high reliability componentry will improve compressor availability, reduce operating and maintenance costs and increase utilisation.
- Ensure the security standard for normal operations is met across the entire network always – i.e. there should be sufficient compression at each main compression location to provide both a duty and a standby unit, without needing to reconfigure the network or rely on alternate compression locations. There should be sufficient line-pack at all times to meet the time to failure criteria as set out in the Critical Contingency Regulations.
- Provide a contingent operation mode should there be a station level failure (i.e. complete site outage) – there must be an appropriate contingency in place for a station level failure to ensure the network can continue operating at an appropriate length of time. This may be running additional compression or may require the normal operating pressures to be high enough to provide a suitable line-pack to handle station level failure.
- Reduce the total compression load on the system by moving compression out toward the extremities of the network, where flows are lower and identify areas and opportunities where excess load is generated and endeavour to remove from the additional load from the system to reduce the burden on the compression system.
- Reduce emissions by implementing changes to both the operational environment and equipment to ensure emissions are reduced wherever practicable and economically justifiable. This is likely to be a combination of changing how the network works, interactions with the network, how individual machines operate and the physical selection of components within each compression system.

Projects have been undertaken to retrofit and update the compressors with modern equipment, as well as to right-size these as far as is practical to new operating conditions. However, much of the compression fleet now operating on very old technologies and equipment, designed for inappropriate operating conditions.

Currently the network operation is outlined below:

- Mokau operates to control the pressure in Taranaki where all producers are and provide line-pack in the system

- Pokuru compression provides pressure to the Bay of Plenty (500/800 Lines)
- Rotowaro provides pressure to Auckland and the 402 Lateral
- Henderson provides pressure to Northland (specifically the now retired RNZ site)
- KGTP Boosts pressure to Kaitoke, as well as provides pressure to the 200 System
- Kaitoke provides pressure to the 100/700 Lines (Wellington and Hawkes Bay), when flows are high (winter months)
- Mahoenui compressor station is used as a backup station to KGTP to provide pressure/flow in the 200 system
- Kawerau compressor is no longer required to provide pressure to Gisborne due to reduced flows but is maintained operational.

Firstgas have written a security standard for the transmission network which requires 100% redundancy on rotating equipment. This is commonly referred to as the N+1 redundancy requirement.

Several key issues encountered in the current operational system are outlined below.

Due to the potential for major change on the network, the compression strategy outlines taking action to develop a future operational plan and assess the sensitivity of that plan to all possible future outcomes. This will provide a list of potential projects and activities that can be assessed for best fit for all possible future outcomes, or least regrets, which can be pushed forward for implementation.

Compressor Stations

Compressor units are either gas turbines driving centrifugal gas compressors or reciprocating engines or electric motors driving reciprocating gas compressors. Fuel gas is taken from the pipeline for use in the prime movers and is heated in pre-heaters and metered prior to being depressurised for use.

Gas compression sites do not just comprise compression units. The sites need to hold a considerable amount of auxiliary equipment to facilitate compressor operations. Gas detection, control systems, actuated valves and back up electrical generators are all part of the system that makes up a compressor station. SCADA provides remote operation and data acquisition capability for the compressor sites.

Reciprocating Engines

This is largest fleet of compressor units – comprising on 14 compressors. The oldest engines are those located at KGTP – where they have been in service from 1969.Generally compressor lives are reset during major overhauls. However, in addition to no longer being sized correctly for their function, some of these units are operated using outdated pneumatic control systems that have limited ability for SCADA, diagnostics and monitoring capability that is available on newer units.

The reciprocating units were installed with an expected life of 30 years and have been subject to review at the major inspections to allow extension of the life beyond that originally planned.

Reciprocating engines that still employ pneumatic control systems only provide rudimentary online performance monitoring. As such these control systems will become a barrier to improved performance for this type of technology. The OEM maintenance recommendation for pneumatic control systems includes significant intrusive dismantling for component level replacement. However, as this technology is approaching obsolescence there are few technicians capable of performing this work and, more importantly, setting up the control system again to ensure that it operates as intended and does not build in a stress point or failure mode into the system. The mechanical and moving parts of the control system are subject to wear, and this wear reduces the sensitivity and reactions of the system to such an extent that significant machine damage can be experienced without the control system picking up a problem and tripping the system. Finally, the pneumatic system cannot export data to a historian, which means that following a failure, the line of investigation cannot be established with any acceptable level of speed of response, and only the "as found" condition can be used to try and establish the causes.

Reciprocating Compressors

Reciprocating compressors are inspected on a regular basis with the reciprocating analysis equipment sourced from USA. Field staff service and overhaul the wear related components to maintain an optimum operating condition.

The age profile in Figure 24 reflects the installation of the compressor units. The units do not have finite life expectancy and the life of the unit is based on their condition at major overhaul periods.

Electrically Driven Compressors

The newest compressors in the fleet consist of reciprocating compressors driven by electric motors with variable speed drives. These were installed at the Henderson compressor station in 2017, in response to the increased demand on the pipeline due to the upgrade at Channel Infrastructure (formerly Refining NZ). With the Channel Infrastructure converting to an import only terminal, the need for compression has altered dramatically in the short term. However, following the implementation of the compression strategy, the demand for this compression strategy is anticipated to increase in the future.

These units will not have a defined service life. Condition assessments will be conducted during major overhaul periods to assess the condition.

Turbine Compressors

The fleet of gas turbines includes four units on two gas compression sites. Rotowaro Compressor Station and Mokau Compressor station. Mokau CS was constructed during the 1980's and Rotowaro compressor station gas turbines were installed during the late 1990's to compliment the reciprocating units on site.

Gas turbine compressor blades have a limited operational life due to several factors that affect their performance and structural integrity. Blade life is typically expressed in terms of operating hours or cycles.

Rotowaro Compressor Station

The turbine drive unit in Rotowaro Unit #5 underwent a blade inspection to extend the life of the turbine blades in early January 2023. The report from this blade inspection identified that the HP blades installed on the unit have reached the end of their life and should be retired.

Rotowaro Unit #6 was also inspected during this inspection and was deemed unfit for service based on nozzle, HP blade and combustion chamber condition.

Mokau Compressor Station

In 2018 the Mokau upgrade project had intended to raise the discharge pressure from the station and required both Unit #1 and Unit #2 to operate to meet full flow conditions. Unit #2 was re-wheeled, however, due to a number of operational considerations the re-wheel of Unit #1 did not proceed. Therefore, for the period of 2018 to August 2022 there has been a considerable mismatch between compressor curves, none being optimal for current flow conditions.

As part of the 2018 the re-wheel project numerous other improvements were commissioned, however some were not fully completed on Unit #1. Items of notable size that are outstanding for Unit #1 are:

- the replacement of the anti-surge valve (ASV)
- introduction of a hot gas bypass valve (HGB)
- conversion to a dry gas seal system (DGS) and
- upgraded fire and gas system.

This outstanding work along with re-wheeling of Unit 1 is currently underway and planned to be completed in FY2024.

Currently the Mokau compressors use the station discharge as the process variable that they control to (discharge pressure control). From a Maui pipeline operation standpoint, it is most suitable to have a suction pressure controller introduced at the Mokau CS to automatically control Taranaki Target Pressure (TTP). The Unit upgrade project also designed the suction pressure and discharge pressure control for both units. However due to difficulties with the SCADA Modbus, updating of the RTU firmware and the timeframe available this wasn't installed during the commissioning. This work will now need to occur during the station outage for the Unit #1 re-wheel.

Fire and Gas Detection Systems

The fire and gas detection systems provide an important line of defence in protection of the assets and are also linked to the logic and start permissive for each unit. The systems have been updated in an ad-hoc manner and comply to the standards in force at each upgrade with the latest version of *NZS 60079* removing the grandfather clause that will require self-qualification of these installations to the original installation standards. The equipment is subject to a point-to-point function check on an annual basis. Any faults found during operation are resolved immediately.

Fire and gas protection systems for other stations are described under station ancillaries.

Compressor Control System Support

There are well developed electronic control system back-up and disaster recovery procedures for Rotowaro compressor station controls systems. The programmable logic controller (PLC) configurations are stored on common Firstgas drives and on site. PLC configuration revision format control allows easy identification of the latest version and catalogues any changes to the programmes. Back-ups take place on a scheduled basis.

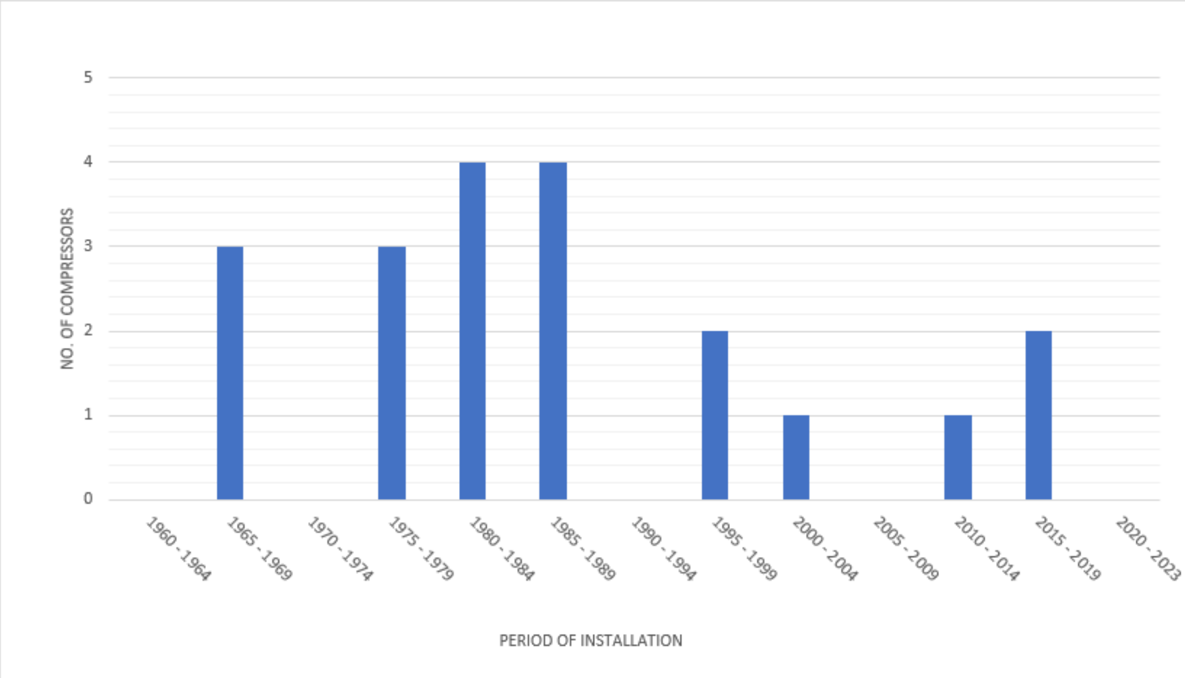
The changes in operating philosophy and upgrades allow for a more robust method of collecting and analysing the performance data. An effective historian system that is dedicated and developed for collecting and storing operating data provides the appropriate level of data and information investigation that supports the excellence in operation that is being targeted. The historian servers will be installed as part of the machine control systems. Base line performance data can then be captured as an ongoing performance comparator.

Firstgas maintains spare PLCs as recommended by the OEM on a live powered rack in Bell Block. Due to the recent control systems upgrade at Pokuru and the development at the Henderson compressor station, it is intended to provide the same facility in Hamilton. This will provide readily available spares support for the northern regions.

Gas Coolers

Gas coolers cools down the hot compressed gas generated by gas compressors, enabling efficient operation and protecting downstream equipment from excessive heat. By maintaining the gas at an optimal temperature. A remain life review has driven a replacement programme for the gas coolers over the course of the last 5 years. The final cooler to be replaced is KGTP Unit 2.

Figure 24: Compressors Age Profile



Risks and Issues

Reliability: The current compression fleet consists of relatively old machines (install dates in the 70s-80s primarily). Most of the engines, compressors, utilities and control equipment has long since been superseded or have not followed the upgrade path typically expected for such machines. The age of the equipment is now such that age-related failures are increasingly common, as well as the reliability that can be offered by more modern robust equipment is not being achieved.

It should be noted that many of the machines are no longer fit for purpose for the operating requirements, resulting in excessively loaded or unloaded machines. This leads to reliability issues where multiple machines are required, or performance issues are impacted because of significant and continual underloading.

Efficiency: The current unit locations and sizing are based primarily on conditions that existed in the 80s and 90s. Most compression stations are now either grossly over or under sized and operate at compromised operating points based on the existing unit sizing, reliability and perceived issues and or weaknesses in the system. Units operating grossly underloaded are prone to reliability issues, and undersized units for the application, require additional units to be run to be able to meet the operational parameters.

Emissions: The existing compressor fleet runs on old gas driven engine technology, with little consideration given to thermal efficiency. Additionally, the design of the existing fleet does not consider emission reduction technologies and techniques that have been developed over the past 30 plus years. Ultimately, the operational setpoints and procedures of the compression locations do not currently consider emissions reduction opportunities. Firstgas, as a member of the climate leader’s coalition, has committed to a 30% reduction to its carbon footprint by

2030. As the compressors are the single largest source of emissions by far, their reduction in emissions is central to meeting this target.

Security of Supply: The security of supply standard requires N+1 redundancy for rotating equipment. In practice this requires complete redundancy for all normally operated compressors. While almost all stations have multiple compressors, due to the changes in sizing demands and pressure requirements that have occurred over time, some of the stations require more than a single compressor to be operating at one time to meet the normal demand requirement. Consequently, there are no longer sufficient machines to truly reach a N+1 redundancy requirement of full flow. This is predominantly an issue at KGTP, Kaitoke and Pokuru compression locations.

Key Projects

Kaitoke Compressor Station

Reliability					
Compressor	2018	2019	2020	2021	2022
Mokau 1	100.0%	99.5%	98.5%	99.6%	98.7%
Mokau 2	100.0%	97.7%	98.6%	99.6%	92.3%
Henderson 1	99.9%	99.9%	99.7%	98.9%	97.9%
Henderson 2	99.9%	99.7%	99.7%	99.1%	97.1%
Kaitoke 1	97.3%	67.0%	98.2%	98.8%	98.9%
Kaitoke 2	93.8%	86.6%	98.3%	99.3%	98.5%
Kapuni 2	98.2%	99.4%	99.8%	90.2%	94.3%
Kapuni 3	99.2%	100.0%	97.9%	94.7%	99.9%
Kapuni 5	99.5%	91.2%	79.5%	86.4%	84.5%
Kawerau 1	98.4%	98.6%	99.7%	97.5%	93.5%
Kawerau 2	82.0%	98.0%	74.9%	97.5%	92.1%
Mahoenui 1	75.6%	97.2%	78.8%	98.6%	89.2%
Mahoenui 2	63.4%	97.8%	94.7%	95.9%	99.3%
Mahoenui 3	67.3%	24.5%	80.7%	98.5%	100.0%
Pokuru 1	99.9%	91.2%	99.9%	97.7%	99.6%
Pokuru 2	99.0%	99.4%	97.5%	99.9%	99.7%
Rotowaro 3	99.7%	99.7%	71.7%	87.1%	100.0%
Rotowaro 4	100.0%	99.4%	71.5%	87.1%	95.2%
Rotowaro 5	100.0%	100.0%	100.0%	85.3%	13.2%
Rotowaro 6	99.4%	99.4%	99.8%	80.5%	100.0%

Replacement of the Kaitoke Compressors is a significant project that is currently underway and expected to be completed over the course of FY23 and FY24. Kaitoke no.1 compressor is undersized for full flow requirements for the Southern Gas Transmission Network. The Kaitoke Compression Project intends to install two new 50% compressor packages to provide compression over the full range of demand. These new compressors will operate alongside the existing unit #2 compressor, providing N+1 redundancy. The other existing unit #1 compressor will be decommissioned once the new compressors have been installed.

Rotowaro Compressor Station Unit 5 Turbine Re-blading
Rotowaro Compressor Station Unit 5 Gas Turbine blades have reached their end of life these will be replaced to keep unit operational. This work is planned to be completed in FY2023.

Mokau Compressor Station Re-wheeling

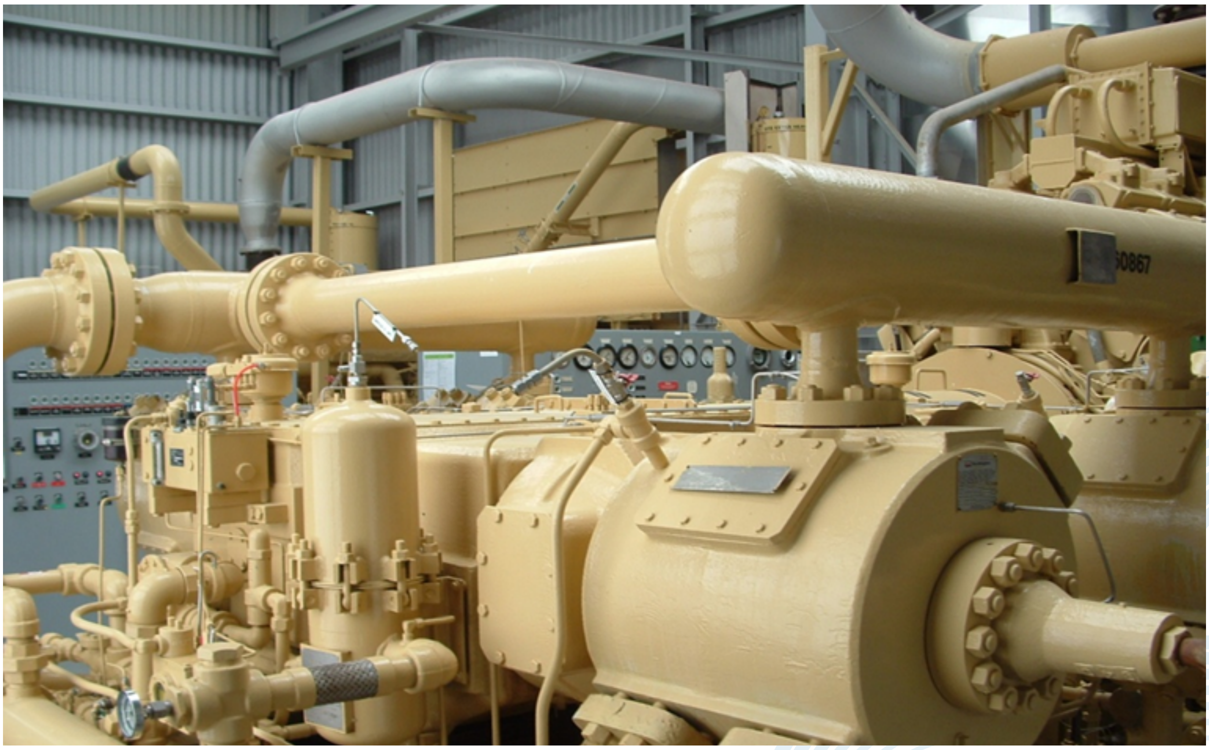
Compressor re-wheeling is performed to improve the efficiency, capacity, or adaptability of a compressor to specific operating conditions. This will alter the performance characteristics of the compressor to a configuration that is optimal for current flow condition and will provide the following:

- Ability to work with as large operational imbalance as possible
- Discharge pressure to be as high as possible
- N+1 compressor redundancy (matched compressors)
- Install Dry gas Seal system. Dry gas sealing systems retrofitted into centrifugal compressors are now recognised as a cost-effective means of improving equipment performance

Kapuni Gas Treatment Plant

KGTP unit 2 cooler replacement (underway)
Upgrade of fuel gas isolation systems
Wonderware servers to be replaced through planning period

Figure 25: Typical Reciprocating Gas Compressor



C.9. Station Components

Stations are above ground installations along the pipeline that contain a range of equipment designed to either receive, transmit or deliver gas safely and efficiently to customers. Stations contain various asset components.

Equipment is in dedicated securely fenced compounds in safe positions relative to the external environment. Signage and access roads to compounds (where required) are provided. Some sites have mains power supply and security lighting.

Delivery points reduce the gas pressure in the system prior to it being delivered to customers and/or into downstream distribution networks. Delivery point equipment can include several components including:

- Filters
- Heating systems
- Isolation valves
- Pressure regulators and control valves
- Pressure safety valves and slam-shut valves
- Metering systems
- Pilot valves
- SCADA telemetry
- Ancillaries

Figure 26: Typical Delivery Point

Other stations contain equipment associated with the operation and maintenance of the system, including:

- Compressor units
- Main line valves
- Metering systems
- Odorisation plant
- Coalescers and filter/separators
- Gas chromatographs
- PIG launchers and receivers

Stations and original installation dates are listed in *Appendix D – Asset Fleets*.

C.10. Heating Systems

When gas pressure is reduced by pressure regulators at delivery points the gas temperature reduces due to the Joule-Thompson effect. To maintain gas temperature above the lower limit specified in *NZS 5442* - Gas Specification for Reticulated Natural Gas and to prevent equipment harm and/or malfunction, gas is heated to an appropriate temperature prior to the pressure being reduced. Heating systems are used for this purpose and are critical to the safe and reliable operation of gas pressure reduction equipment.

Heating systems are either gas-fired water bath heaters (WBHs) or electric heaters. A WBH is a heat exchanger containing water in a vessel which is heated by combusting natural gas in a fire tube contained in the vessel to heat the surrounding water. Pressurised gas flow tubes are also contained in the vessel and act as heat exchangers to raise the temperature of the gas stream. Typical operating water temperature is 60ºC and typical process temperature gain of the flowing gas is 25ºC. Electric heaters heat the gas directly by passing the gas through a vessel that includes the heater elements.

Gas-fired WBHs contain several components including:

- Water bath shell containing the water tank, fire tube and gas tube coil
- Gas-fired pilot and main burner unit
- Temperature controller
- Fuel gas train
- Fuel gas meter (where installed)
- Pilot burner pressure switch connected to SCADA (where installed)
- Low water level protection switches (where installed)

Electric heaters contain several components including:

- Electric heater pressure vessel including electric elements
- Control system

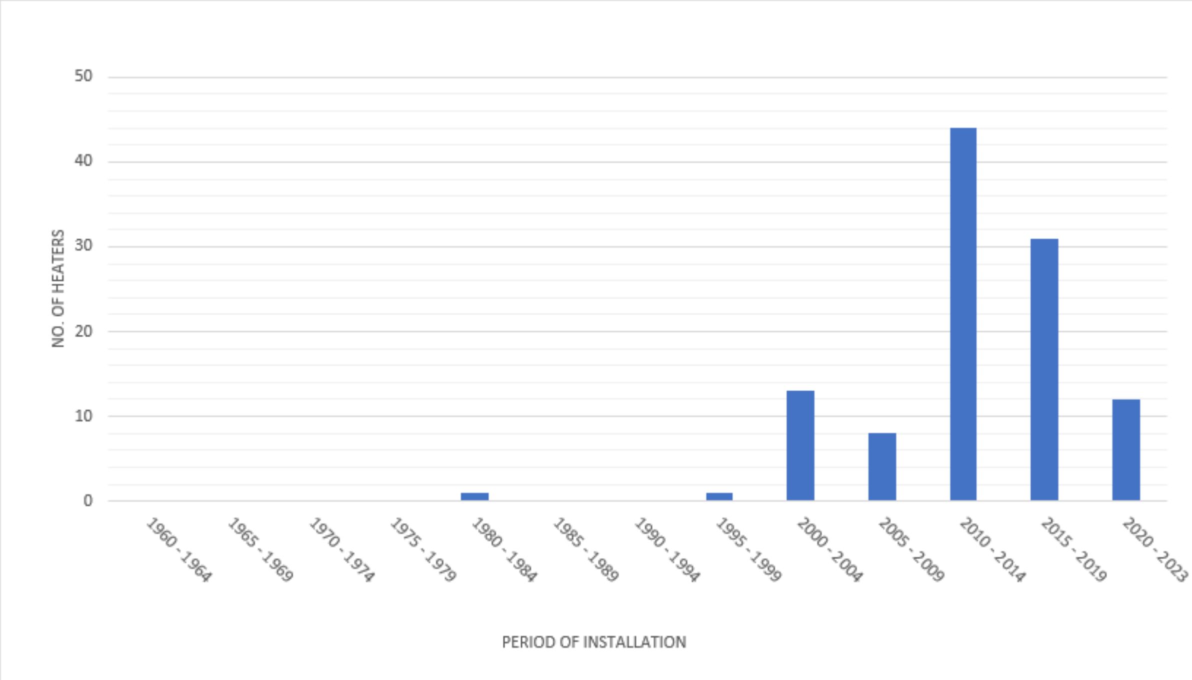
Heating systems are typically incorporated within the following stations:

- Compressor stations to maintain gas temperature to be used as fuel gas for prime mover
- Delivery points (some delivery points contain more than one heating system).

Gas-fired Water Bath Heaters (WBH) account for 97% of the fleet with electric powered making up the remainder.

There has been significant uplift in the overall condition of the Water Bath Heater shell and pressure coils. This has prompted a change in the approach to the heaters. The approach is to now be more of an inspection based, with an anticipated asset life of 40years. When the unit would likely be replaced.

Figure 1: Water Bath Heaters Age Profile



Condition

Due to the significant improvement in the overall condition of the pressure coils and shells of the water bath heaters. Up until now, the main emphasis has been on adhering to the pressure equipment management plan and ensuring the integrity of the water bath heaters, with other issues addressed on an as required basis. With the integrity plan being closely managed there is capacity to undertake further improvements to the fleet of water bath heaters.

Risks and Issues

Several issues have been identified associated with heating systems including:

- Obsolescence of components of gas fuel trains
- Maintenance issues with inadequate space to effectively maintain the units (working space)
- Limited safety features on older heaters
- Hazardous area non-compliance
- Reliability issues - predominantly flame out

Key Projects

- Continue with the inspections-based programme for the pressure coils and shells.
- Develop programme to address legacy fuel train and burner box issues.

C.11. Odorisation Plants

The purpose of gas odorisation is to provide a means for the detection and location of gas escapes. Gas must have a distinctive and unpleasant odour so that it can be readily detected in the air by anyone with normal sense of smell, well before a combustible gas/air mix develops.

Under the Gas (Safety and Measurement) Regulations 2010 the legal obligation for gas odorisation is placed with the gas distribution network owners and gas retailers. Firstgas provides gas odorisation services to gas distributors and retailers by odorising the gas in the Kapuni transmission system. Odorant levels are regularly monitored at selected locations on the gas transmission system and gas distribution network to ensure satisfactory odorant levels are being maintained.

Gas transmitted through the Maui pipeline and the 300 line (Frankley Road Interchange with the Maui pipeline to Kapuni Gas Treatment Plant (KGTP)) is *not* odorised. Gas transmitted through all other pipelines is odorised. Gas is odorised using electronic pumped odorant injection systems supported by bulk odorant storage tanks at KGTP and the major receipt points from the Maui pipeline. These are Rotowaro compressor station, Pokuru compressor station and Pirongia.

All pumped odorisation systems are monitored by the SCADA system. Some pumped odorisation plants incorporate two or more pumped systems to provide operational N+1 redundancy. Pumped systems operate by measuring gas flow and injecting proportional quantities of odorant into the gas stream to meet prescribed levels.

Minor receipt points along the Maui pipeline are installed with mobile bypass odorant vessels. Odorant is proportionally entrained (pulled) into the gas stream using an orifice plate pressure differential.

Odorant chemical is imported in bulk, this is then distributed to the bulk storage locations and mobile bypass units are refilled as required.

Pumped odorisation plants contain several components including:

- Odorant pump(s)
- Electronic control unit(s)
- Odorant tank

Mobile bypass odorant plants are self-contained units.

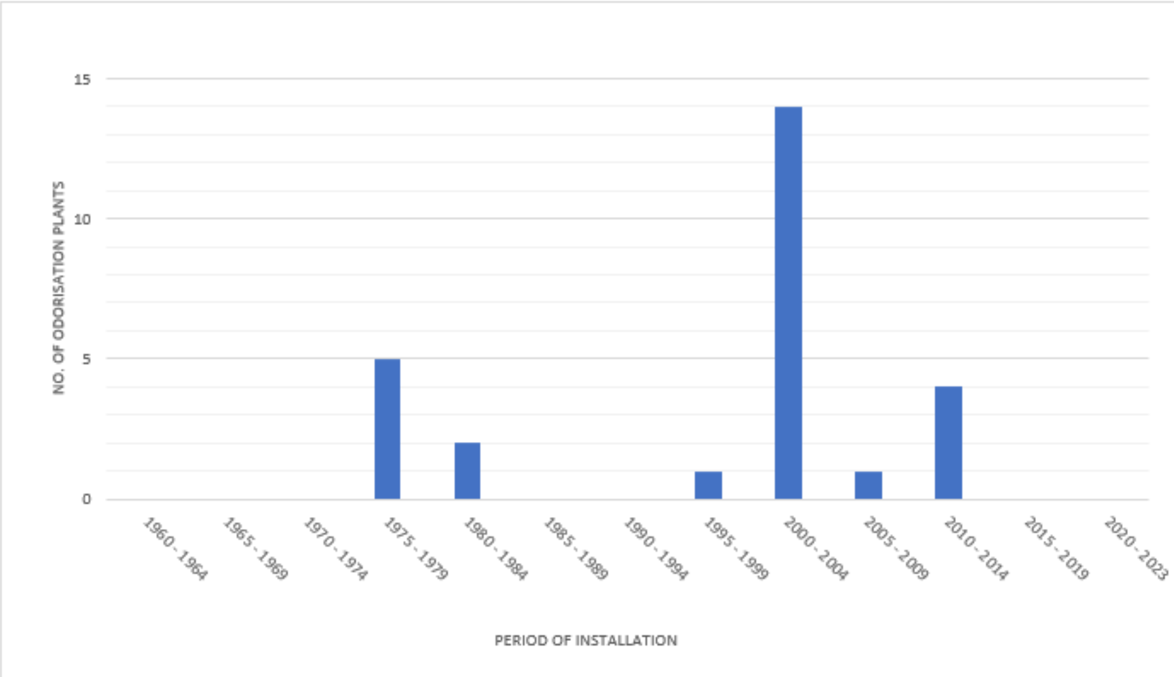
Fleet Overview

Bulk odorant is stored at four main locations throughout the transmission system, Pirongia, Kapuni Gas Treatment Plant, Rotowaro and Pokuru Offtake.

The odorant systems located at various sites have had multiple modifications throughout their service life. The main injection plant is reaching its end of life and as such options are being considered for the long term.

The existing injection systems

Figure ??: Odorisation Plant Age Profile



Condition

Maintenance practices for the odorant systems have been reviewed and procedures to align with industry best practice, have been updated.

Risks and Issues

Due to the aging profile of the odorant injection system and obsolescence of equipment, there is a risk that components could fail on the primary injection system with no replacement component available. The systems are fitted with redundant odorisation capability via bypass odorant systems, should the primary system fail. This ensures that odorisation can continue in the event of primary system failure.

The injection plant at Kapuni gas treatment plant is proving to be unreliable and obsolete.

The Standby tank at Pokuru is installed in a bund at ground level. The design of the enclosed area makes it difficult to monitor for external corrosion.

Key Projects

The replacement of the Kapuni Injection plant is expected to be completed in FY2024. Ongoing replacement and odorisation requirements will be determined once the project has been completed.

C.12. Coalescers and Filter/Separators

Coalescers and filter/separators are used to protect downstream facilities such as compressors, pressure regulators and meters from fine particles of liquid contaminants and impurities in the gas streams. Fine particles flow into the coalescer cartridge and are trapped by impingement. As these small liquid particles contact with each other they coalesce into larger droplets, eventually becoming large enough to drip or flow down to the liquid receiver tank where they remain until drained away. Coalescers vary in size and capacity.

Coalescers are generally distinguished from other filtration assets by their ability to separate and capture liquids from within the gas stream.

Filter separators are very similar to coalescers due to their ability to separate out and capture liquids while also providing filtration of solid particles in the gas stream. They contain additional filtration for capturing particles but operate using a similar principle to a coalescer for capturing liquids.

Figure 28: Typical filter separator

Coalescers and filter separators contribute to achieving compliance with *NZS 5442:2008* - Specification for Reticulated Gas by reducing contaminants within the specified limits.

Coalescers are installed on the discharge side of compressor stations to prevent oil mist carry over into the pipelines from compressor units. Filter separators are installed on the suction side of compressor units to protect the prime movers from contamination. Coalescers and filter separators are also installed at some large delivery points including those that supply power stations where gas quality is an important factor.

Filter Coalescers and filter separators contain several components including:

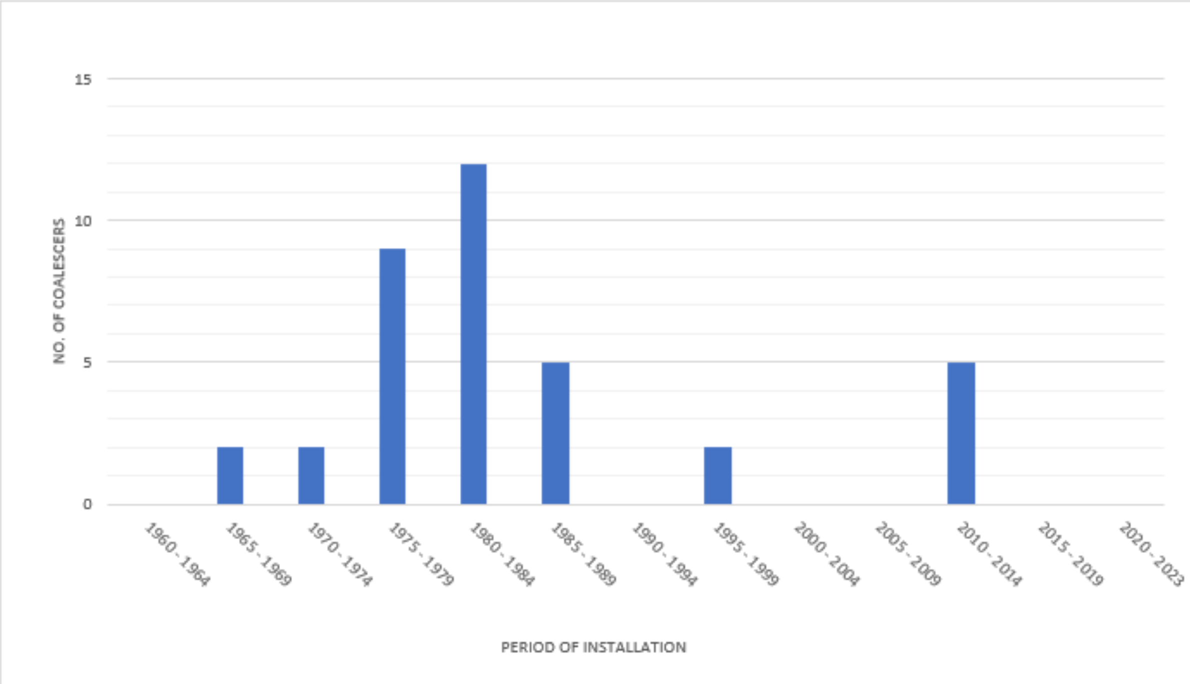
- Coalescer and filter separator pressure vessel
- Pressure safety valve
- Filtration elements
- Instrumentation
- Dump valves
- Liquid sump tank

Fleet Overview

Coalescers and filter separators are managed under the Firstgas Pressure Equipment Management Plan - 3206146 and inspected in accordance with *AS/NZS 3788: 2006* Pressure Equipment In-Service Inspection. Ageing fleet is not as efficient as newer units.

Accredited Agency internal inspection intervals are recommended by the inspection body and are based on inspection history. Coalescers are typically not replaced unless performance issues or operational conditions change.

Figure 2: Coalescers Age Profile



Condition

Coalescers are managed through the pressure equipment management plan. This requires internal and external inspection on the vessels at prescribed intervals.

Filter separator/Coalescer unit life expectancy is the same as the station in which it is installed. Any future replacement programme would be driven by:

- Obsolescence of the filter element
- Operational/maintenance costs
- Changes in operational capacity
- Where current station filtration is not deemed to be appropriate for station equipment

Risks and Issues

The majority of Firstgas large coalescers were installed at the time of construction of delivery point or compressor station. Design and knowledge of coalescers has improved over time resulting in older units not performing as would be expected of new units. This is particularly an issue during pigging operations where there could be contamination carry over. In addition to the inefficient designs relief sizing requirements on the units has changed – which may result in the need to upgrade the relief sizes associated with the vessels.

Some of the smaller station filters are based on outdated filtration technology that would not meet current requirements.

Although these issues have been highlighted, the requirement to mitigate the issues is generally a lower priority. No specific programmes have been identified.

Key Projects

No key project identified. Work undertaken would likely be opportunities and tied in with other work.

C.13. Metering Systems

Metering systems are used to provide accurate gas volume flow data. Meters have rotary-displacement, turbine, ultrasonic, mass flow or diaphragm gas volume measurement mechanisms. In most cases failure of metering equipment will not impact the flow of gas through the system.

Gas is measured in energy quantities for trading purposes. Meters measure gas in volume quantities which are converted to energy quantities by the additional components forming part of the metering system. Gas chromatographs provide gas composition data to the metering system and transmitters provide pressure and temperature data. Data is compiled and stored in correctors or flow computers where the energy calculation is computed. In most cases metering data is transmitted to the gas control at Bell Block by either Remote Terminal Units (RTUs) connected to the SCADA system or by Autopoll telemetry units. A few minor sites rely on periodic manual download of data.

Metering systems contain several components and may include:

- Flow computers or correctors
- Pressure and temperature transmitters
- Interconnecting pipes (where the metering system comprises two meters)
- Interconnecting electric cables and power supply
- Autopoll telemetry unit (where fitted.

Metering systems are typically incorporated within the following stations:

- Compressor stations
- Delivery points
- Receipt points
- Metering stations.

It is important that Firstgas inspect, maintain, and test transmission meters to ensure overall meter accuracy requirements are met in accordance with the standards. Firstgas needs to update its maintenance and inspection plans to optimise alignment with the meter strategy. Meters shall have a 5 yearly maintenance frequency. If a meter is found with significant contamination during the 5 yearly normal maintenance frequency, a corrective work order will be raised to remove the meter.

Pigging (cleaning and inspecting) of transmission pipelines has the potential to create significant contamination at affected delivery points and their associated meters. The meter maintenance and inspection plan may be modified to accommodate a pigging programme and limit accuracy drift or failure. i.e. it may be prudent to delay reinstalling newly maintained meters at delivery points that are soon to be potentially impacted by cleaning/pigging contamination.

Future design of Firstgas small stations will ensure that in addition to the “primary” meter, a verification meter or space for installation of a second meter be considered, at least temporarily, in conjunction with the primary meter for verification testing. This will give assurance that only compromised meters are removed for maintenance and testing when they are inaccurate or have been in service for 5-years.

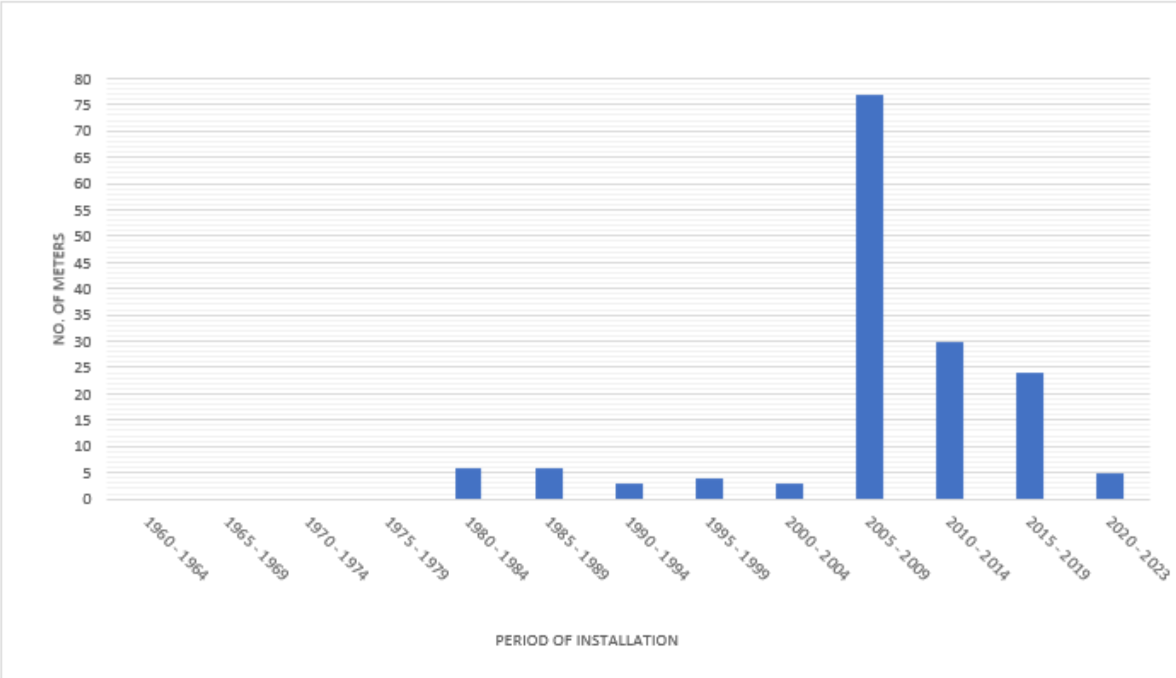
Future design of Firstgas large stations will ensure they have series prove test capability. This will provide capability to conduct 3-monthly in-service (series prove) accuracy test of meters, and this will ensure meters are only normally removed when they are either out of prescribed accuracy tolerance limits or have been in service for 5-years. If series prove tests show approaching or out of accuracy acceptable limits, then the meter may be removed early (within 5-years) and maintained off-site. The current experienced station maximum flow will be used to identify any large stations that require more frequent and more significant on-site maintenance.

Figure 32: Typical Ultrasonic Metering System

Fleet Overview

As an alternative to turbine meters, ultrasonic and Coriolis meters are also now available. This has opened opportunities to retrofit ultrasonic meters into existing turbine type applications. Flexibility of these meters is also an attractive option for both upsizing an existing site while retaining the existing flow tube sizing, as well as building a new site with smaller tube sizing but with the same or better flow capacity. These meters are also capable of bi-directional flow or highly variable flow sites where the turbine meter flow range is unsatisfactory.

Figure 31: Metering Equipment Age Profile



Condition

The approach to how Firstgas manage its meters has changed and is now based on performance of the metering systems. Once a predetermined trigger has been met the meters will be maintained.

Risks and Issues

Meter accuracy can be compromised when operating outside specified minimum and maximum flow rates. Any meters identified as being outside or predicted to operate outside limits due to changing demand profiles will be considered for replacement.

If contamination is present in the system this affects the meter performance and requires additional maintenance to mange

Several issues have been identified associated with metering systems including:

- Corrector power supplies from battery only are prone to poor reliability and a programme of changing over to mains power supply or solar power using existing battery power for back up is in progress
- Corrector pressure sensing connection tubing requires upgrading
- Interface issues between meter and corrector creating reliability issues.
- Daniels Ultrasonic sensors are obsolete – head only available but not sensors.

The issues identified will be addressed through normal business as usual processes and will not require specific programs to address.

Key Projects

- Development of a management plan align to the meter strategy

C.14. SCADA AND COMMUNICATIONS

The SCADA system is fundamental to transmission system operations with the system designed to provide stability, security, and high availability/reliability. A full set of SCADA hardware is maintained to support disaster recovery in accordance with business continuity planning procedures. Power supply is maintained through an uninterruptible supply system, that is backed up by two six-hour reserve battery banks and an emergency generator.

The Firstgas transmission system is monitored and controlled by a SCADA system on a 24/7 basis. This SCADA system is fundamental to transmission system operations and its use includes coordinating the supply and delivery of gas through the pipelines, balancing available supply against forecast demand, and receiving metering system data.

Communication and Control Systems are used throughout the transmission network to measure information, ensure safety, provide visibility to various users, and enable the network to safely deliver the requirements it must meet.

Communications and control systems currently in use in the transmissions network primarily consist of:

- Various Programmable Logic Controllers (PLC) on units, stations, and sites to directly control equipment where required
- Remote Terminal Units (RTU) that measure various variables and transmit and receive information from Gas Control. RTU units vary depending on the site, the control required, and the complexity of control required
- Communication links from remote sites. This enables data to be transferred from the RTU and/or PLC's back to Master Terminal Units. This can be physical, cellular or satellite links
- SCADA master terminal – This is the central point which takes all the data collected by site devices, provided by the various communication links, displays that data to System Control, stores the data and passes it onto other areas of the business. There are two master terminals, a main system at the main control room, and a second back up system, called the disaster recovery centre (DRC)
- Historians – Historians are bulk storage devices. They are used to archive the large amount of data received by a PLC or the Master terminal and allow users of systems to access the data as required. These can be located on site, on the master terminal, or as a central repository for all upstream historians.

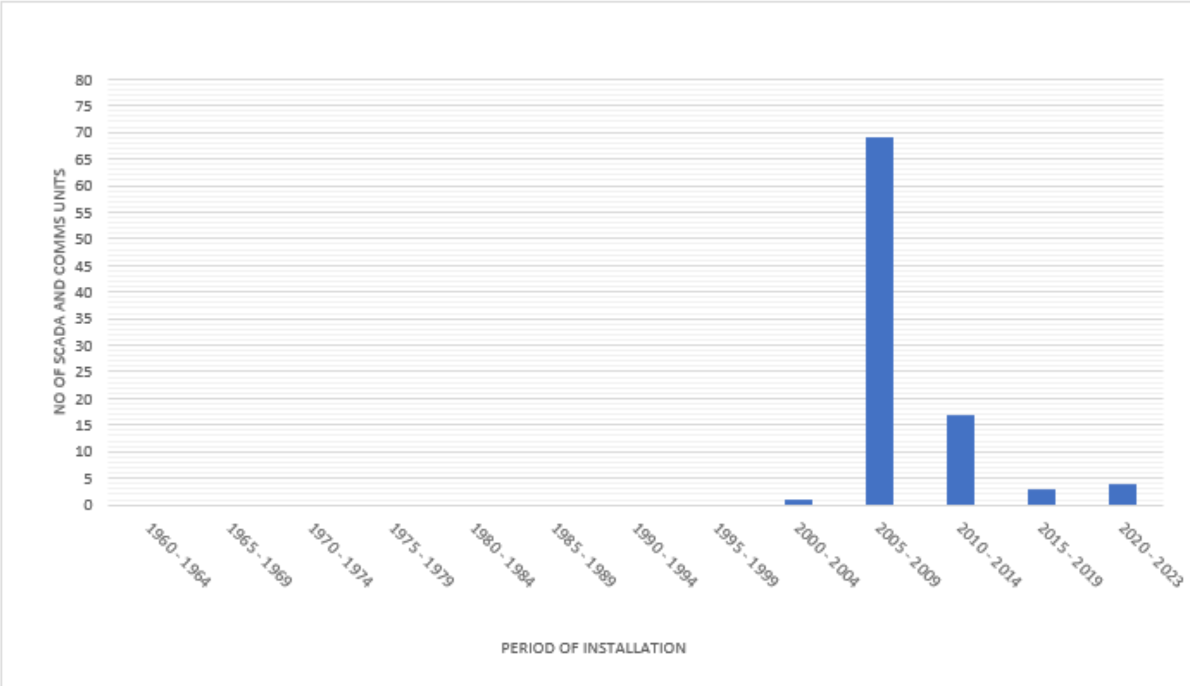
Fleet Overview

The SCADA master station and communications systems located at Bell Block are regularly tested, maintained and inspected by the Gas Control Team with support from vendors. Field devices and associated control systems are maintained, inspected and calibrated by the Transmission Services team.

Improvements in technology are making control systems more reliable and able to perform self-diagnostics. These features also permit a decrease in maintenance frequency. The aim is to achieve the scenario where most of the maintenance is preventative and the minority due to breakdowns. Work continues with communication service providers to migrate to fibre-based communications media solutions at remote stations. Fibre solutions will align with the future direction and maintainability of the service provider.

Many smaller sites are monitored using the Autopoll system and the associated meter corrector equipment installed on metering systems. Some sites have been identified as requiring upgrades from Autopoll meter corrector systems to SCADA and RTU systems to provide enhanced monitoring and alarm capability.

Figure 33: RTU Age Profile



Condition

The existing SCADA master terminal is no longer supported by the vendor. This means that upgrades, security patches and support for the platform are either no longer available, or severely limited.

Station RTU – Existing RTU's at stations are Foxboro SCD5200's. These products are past end of life that parts and support for these products are no longer available.

Several legacy communication systems on the network are in various stages of being decommissioned including:

- Kordia VPN Network
- Spark PSTN Network (Copper Phones lines)
- 2G/3G Cellular Networks.

Some of the existing equipment within the existing communication and control system is only designed to work certain technologies, so the obsolescence of the communication system creates a cascade effect, where wider platforms or equipment are rendered obsolete due to unavailability of the communication system.

The current Autopoll RTU system used to relay metering, pressure and temperature information from small sites, which is reliant on the Spark PSTN network that is currently being decommissioned.

To address these multiple issues Firstgas has three key actions underway.

- A SCADA master system replacement project is currently underway
- An Autopoll replacement is under development
- As the cellular 2/3G disconnections are being rolled out and replacement communications are being installed.

Risks and Issues

The expected useful design life of these systems was expected to be between 7 and-10 years. However, due to the rapid advancement of computer technology, the SCADA system hardware platform has reached the upper limit of its lifecycle and is now obsolete and unsupported. SCADA obsolescence increases the likelihood of failure and exposes Firstgas to increased business and operational risks.

The SCADA strategy identifies the obsolescence of software and communication hardware that will be planned for replacement before failure is likely to cause a business or compliance issue.

RTU individual failures may occur over the replacement period, but actions taken in the immediate term will identify sufficient parts to enable fast resolution of the failure until the complete unit is replaced with the latest technology unit.

Key Projects

- SCADA master system replacements
- Auto-poll replacement
- 2/3G communications replacements.

C.15. Gas Chromatographs (GCs)

The energy content of gas is calculated by flow computers using data obtained from the volume, pressure and temperature measurements and gas composition data derived from a GC.

A GC is a chemical analysis instrument for analysing chemical components in a complex sample. It uses flow through a narrow tube known as a column, through which different chemical constituents of a sample pass in a gas stream (carrier gas, mobile phase) at different rates depending on their chemical and physical properties and their interaction with a specific column filling (stationary phase). As the components exit from the end of the column, they are detected and identified electronically.

The GC thus determines the gas composition and properties, which are relayed to the flow computer to facilitate the calculation of gas energy flow. GCs contain several components including:

- Gas chromatograph unit
- Shelter
- Calibration gas and carrier gas bottles and regulators
- Gas sampling system
- Associated tubing

GCs are typically incorporated in the following stations:

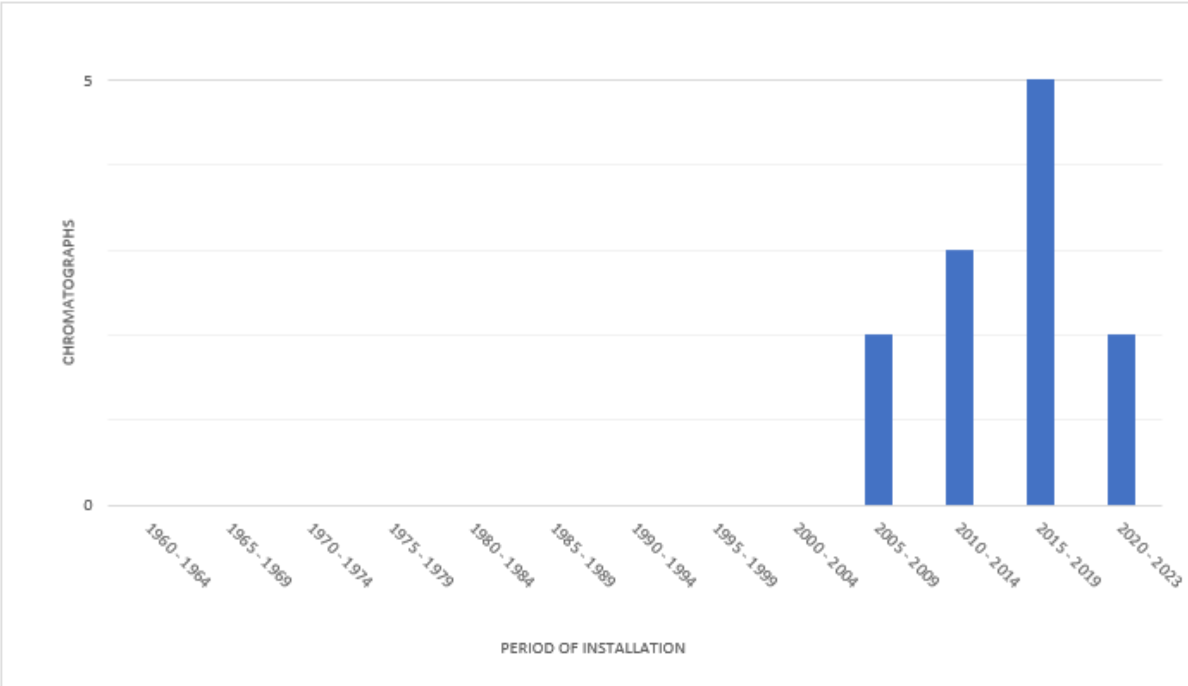
- Compressor stations
- Delivery points
- Mixing stations

Fleet Overview

A programme of GC replacement is in place considering the recognised design life of 10 years.

Calibration accuracy of a GC is largely dependent on the accuracy of the calibration gas used as a reference. One important consideration is storing the calibration gas above the gas dewpoint.

Figure ??: Chromatographs Age Profile



Risks and Issues

There are currently no significant risks or issues associated with the gas chromatographs.

Key Projects

Kaimiro GC Install

C.16. PIG LAUNCHERS AND RECEIVERS

PIG launchers and receivers facilitate the use of In Line Inspection (ILI) survey tools for pipeline condition monitoring and internal cleaning tools. PIG receivers also act to contain and facilitate safe disposal of debris which is removed from the pipeline by PIGs.

A PIG is a device which fits into the pipeline and is pushed along by the gas flow. PIGs can be used for internal cleaning (or scraping) of pipelines. Inline inspection (ILI) survey tools can also be equipped with sophisticated sensors to examine the pipeline for corrosion, geometry and spatial positioning.

A PIG launcher or receiver contains the following main equipment items:

- PIG launcher or receiver vessel both of which incorporate quick-release closure doors
- Kicker lines, valves and pipework to equalise pressure and vent the launcher or receiver.

PIG launchers and receivers may be incorporated in the following stations:

- Compressor stations
- Delivery points
- Receipt points
- Dedicated PIG launcher and receiver stations

Fleet Overview

ILI tooling has changed over recent years to accommodate the latest technology developments resulting in ILI tools becoming longer. Longer ILI tools are also designed to accommodate multi-tooling to avoid having to run tooling more than once.

It was identified in a post ILI survey report in 2012 that modifications to PIG receiver and launchers will be required to properly accommodate the latest tooling. One solution considered in FY2014 was to use standard portable pig launchers/receivers. Due to variances in station design this option was not considered economical or practical as many stations would need to be modified to accommodate the portable launchers and receivers. In addition to launcher and receiver tooling requirements, existing launchers and receivers should be modified to include best practice design to ensure tools can be launched and received in a safe manner.

PIG launchers/receivers were typically installed during construction of the pipeline, and with a few exceptions there has not been a significant investment to accommodate the changes in pigging technology.

A programme has been developed to upgrade the pig traps to incorporate the multi-vehicle technology and HSE initiatives. Modifications will be programmed to align with the ILI survey schedule.

Condition

The pig launchers/receivers are either located in stations that are specifically built to launch and receive PIGs or are part of an existing delivery point or compressor station. As such the pig launchers/receivers can be viewed as extension of the pipeline. Maintenance routines to inspect the condition of the above ground pipework and pig launchers/receivers is undertaken to ensure that the equipment remains at an acceptable standard. Typically, areas on the pig launchers/receivers that are susceptible to corrosion are at the support interfaces.

Risks and Issues

There are no specific risks identified with the PIG launchers/receivers provided that the upgrade programme proceeds as forecast. Failure to continue with the upgrade will result in the increased risk potential for injury to field staff. Pigging campaigns are a considerable draw on resources and by reducing the number of runs per section of pipeline and by modifying the pig launchers/receivers to be able to utilise multi-vehicle technology, there will be a reduction in the overall staffing requirement in the field.

Key Projects

The upgrade programme continues in FY2024, prior to the next ILI campaign for the particular sections of relevant pipelines. The intention is to complete the upgrades prior to the individual ILI runs, so that the new technology can be incorporated with the next campaign thus minimising a risk to field staff and reducing the number of runs that need to be completed per a section of pipeline. There is a new design approach for the traps that have been used to define the pig trap modifications required, and the traps are planned to be upgraded in the year before being used for the next intelligent pig runs, to spread the work. One of the main changes is that the traps need to be extended to meet the latest pig dimensions.

Piggability upgrades:

- 504 Rotorua/Taupo Offtake to Reporoa line
- 702 Foley Road line
- 434 Whangarei lateral
- 435 Kauri lateral
- 421 Te Awamutu North lateral.

C.17. PRESSURE REGULATORS

Pressure regulators reduce the pressure of the flowing gas to a pre-determined downstream pressure. Pressure regulators form part of delivery point equipment that supplies gas at reduced pressure to gas distribution networks, directly to customers or to downstream parts of the transmission system.

A variety of different makes and models of pressure regulators are installed to provide the required capacity at the set pressure in the downstream system. The complexity of pressure regulators varies from relatively simple spring and diaphragm designs through pilot operated valves and more complex pressure control valves. Pressure regulators that utilise electronic or pneumatic valve positioning mechanisms are known as pressure control valves.

Pressure regulators provide a barrier between sections of pipeline with different MAOPs and are therefore an essential component for the prevention of over pressurisation of a downstream pipeline. Typically, a second ‘monitor’ pressure regulator is fitted as back up to the working regulator, should it malfunction. A second pair of regulators provides a standby stream to ensure gas supply is maintained should a fault occur on the working stream and to allow maintenance to be carried out without interrupting supply. AS 2885 requires secondary pressure protection which is provided by a monitor regulator and/or by slam-shut valves and pressure safety valves.

Pressure regulators are normally incorporated within the following stations:

- Compressor stations
- Delivery points.

Small pressure regulators are also contained within various instrumentation and control systems.

Fleet Overview

Regulator reliability is determined by the frequency and severity of regulator failure. A reliable regulator will not require frequent adjustment, will be tolerant of varying environmental conditions and gas types/conditions and will not be prone to frequent or significant failures. Regulators that exhibit serious reliability problems will be replaced on an as required basis.

Regulators are considered to perform well if they can deliver the required flow at a consistent delivery pressure, without undue droop at high flow and undue leakage at zero flow. Changing demand conditions may result in regulators that were previously regarded as performing adequately, being deemed inadequate. Regulators which are not capable of delivering within required pressure/flow criteria will be replaced on an as required basis.

Pressure regulators that have become obsolete or face impending obsolescence, will be replaced in a phased manner. The urgency of the programme will be driven by the forecasted availability of the serviceable parts.

Through the pipeline life there have been various types and designs of regulators that have been installed throughout the system. Asset age is not a trigger to replace regulators and a large number have exceeded their design life. Provided that parts are readily available and asset performance is not compromised the equipment can remain in service.

The following criteria are used to assess whether a particular type of regulator needs to be replaced:

- Reliability
- Maintainability
- Performance
- Obsolescence.

Condition

A significant programme to replace obsolete regulators has been completed in preceding years. Currently the fleet of regulators is in good condition. There are a few locations that require replacement of the regulators due to obsolescence. Replacement of these will be completed during the planning period.

Risks and Issues

A regulator is considered obsolete if it is no longer manufactured and if its parts can no longer be obtained. Generally, the regulator body will remain serviceable and therefore the availability of spare parts determines whether the regulator can remain in service.

In instances where it is noted that there is contamination build-up, those regulators will be subject to specific maintenance plans to ensure contamination does not impact on performance.

Key Projects

Currently there are no key projects planned for pressure regulating devices, however, a small number of regulators sets will be replaced through out the planning period as required.

C.18. Pressure Relief Valves

Pressure relief valves are installed to protect pipelines or pressure vessels from over pressurisation. Pressure relief valves limit pressure to a pre-determined value by safely venting gas contained within the protected equipment to atmosphere. The specific requirements vary significantly due to varying pressure ranges and required flow rates, consequently a wide variety of valves are installed across the asset base. Designs and complexity also vary from simple direct spring resistance to more complex pilot operated valves. Pressure relief valves are also known as pressure safety valves.

Over-pressure protection of downstream pipelines or gas distribution networks is normally incorporated with the pressure reduction arrangements at delivery points and therefore forms part of the pressure control systems specified in AS 2885. These pressure control systems are designed to prevent protected systems from exceeding MAOP under steady state conditions and 110% of the MAOP under transient conditions. It is mandatory under AS 2885 for a secondary pressure limiting device such as a pressure relief valve, to be installed.

Pressure relief valves are typically incorporated in the following stations:

- Compressor stations
- Delivery points
- PIG launcher and receiver stations

Small pressure relief valves are also contained within various instrumentation and control systems.

Fleet Overview

The age of a pressure relief valve is not considered a criterion for replacement. Reliability is determined through regular testing incorporated into the maintenance schedule. An unreliable relief valve will not attain the correct set pressure, will not achieve full lift during pressure relief and will have a much higher re-seating pressure than the set pressure. Some relief valves are prone to ‘chatter’ caused by the valve opening and closing rapidly and repetitively, striking against the seat sharply many times a second. In some serious cases, relief valves will not re-seat or internal parts are damaged during relief operation. Relief valves that exhibit serious reliability issues will be replaced through a campaign. The replacement timing is based on the number of valves to be replaced and the optimal replacement frequency considering other station works.

A relief valve is considered obsolete if its soft parts can no longer be obtained. Relief valves that are obsolete or face pending obsolescence will be replaced in a phased manner.

The following criteria are used to assess whether a particular type of pressure relief needs to be replaced:

- Reliability
- Performance
- Obsolescence

Condition

The fleet of relief valves has been part of a substantial replacement program in the preceding years, and generally are in a good condition. Some type issues have been identified with a particular brand of relief valve where the bodies are experiencing issues where the body components can seize together.

The plug valves at Wanganui wouldn't provide a double block and bleed capability for equipment isolation

Risks and Issues

The configuration and equipment specification for the majority of pressure relief valves at Firstgas stations does not meet the standards of the new built stations.

Many delivery points are fitted with:

- High-capacity (50% or 100%) PSVs, without slam shuts.
- Only token PSVs (typ 10% or less), without slam shuts.

Due to the location of some of these sites being either in industrial or urban areas there may be a requirement to replace the PSV or upgrade the site to include slamshuts.

Fugitive emissions resulting from some types of pressure relief valves.

Key Projects

- Type issue replacement of seized relief valves – at this stage it is not considered to be a complete replacement of the flet, but on an as required basis.
- Evaluation and development of a program to upgrade stations to incorporate Slam shuts - prioritised on stations with high capacity/locations

C.19. Isolation Valves

Isolation valves are used to isolate sections of station pipe work, instrumentation tubing, equipment, or control systems to facilitate maintenance, replacement, or emergency shutdown.

Isolation valve types currently in use include ball valves, gate valves, plug valves, globe valves and needle valves. Isolation valves are easily accessible and operable.

Most isolation valves are hand operated either via a lever or a rotary hand wheel via a gearbox. Some valves are actuated and may be operated via an electric motor, gas actuator or gas and oil actuator. Isolation valves are predominantly installed above ground.

Below ground isolation valves are operated by a purpose made valve key or by an above ground valve extension and hand wheel. Isolation valves are connected to pipeline systems by either bolted flanges or by welded connections or a combination of both. Smaller valve dimensions may have threaded connections.

Isolation valves are incorporated within all stations.

In general valves are expected to last the lifetime of the asset to which they are connected. However, valves need to be replaced on a reactive basis where:

- The valve cannot be practically actuated
- The valve is passing
- The valve is leaking
- In the case of plug valves, the amount of lubricant being installed is compromising the operation of the downstream asset
- The cost of repair outweighs the cost of replacing the valve.

There are over 8000 valves throughout the gas transmission system. A central register for faulty valves is maintained to aid the coordination/prioritisation of repair, replacement and investigative work. Therefore, all asset-related risk is retained in the central register and work is prioritised based on risk. Replacement of faulty valves is expected to be an ongoing programme as the asset age profile increases.

Replacement cost is largely based upon the complexity of the engineering works required. Some replacements are relatively straight forward and require either isolation to a section of pipe work in a station and/or temporary bypass where a valve can then be removed and replaced using bolted flanges.

Some valves have gas actuators fitted to facilitate remote or local operation. The Bettis actuators fitted to many of these valves are becoming un-economic to maintain as they often require major refurbishment to allow continued use. Currently the lead time for soft parts is in excess of 26 weeks and it is expected that the supply of overhaul kits will cease over the next few years. It is intended to commence an actuator replacement programme throughout the planning period.

Condition

The condition of isolation valves is dependent on the environment that it they are operating in and the operation that they have been subjected to. Typical issues associated with the isolation valves are:

- Compromised valve sealing ability
- External corrosion
- Valve operability (valve becomes seized or stiff to operate)
- Valve containment lost

Risks and Issues

More complex valve replacements require sections of pipeline to have a stopple fitted to isolate the valve and/or the cutting of welded joints. Planning and engineering support into these projects far exceed those required for a straight-forward replacement. A continued programme to address faulty valves will be maintained, to ensure that faulty valves are addressed in a timely and prioritised manner.

Working with 'live gas' has been successfully trialled, and this provides an alternative option when planning for replacing faulty valves. These techniques are now expected to be utilised more often as significant cost and time efficiencies can be gained.

Key Projects

Typically faulty valve replacements are prioritised based on risk, where possible the works will be completed with other works planned on the site.

C.20. Filters

Filters are installed to remove solid particulate contamination from the system and protect downstream equipment from erosion by impingement and blockage from build-up of contaminants. This is particularly important for equipment with small tolerances or clearances.

Filters also contribute to achieving compliance with *NZS 5442* - Specification for Reticulated Gas by reducing contaminants to within the specified limits.

A large variety of filters are installed across the system ranging from small instrumentation filters to large vessels incorporating quick opening closures. The choice of filter installed depends largely upon the capacity requirements and the desired filtration level required.

Filters are incorporated within stations of the following asset classes:

- Compressor station
- Delivery points
- Receipt points
- Metering stations.

Condition

In general, filters are not subject to significant deterioration if external corrosion is prevented. Non-destructive testing of large filter vessels sometimes reveals material defects which require remediation, but these defects are usually believed to date from original construction.

Risks and Issues

Some small filters are of an outdated design and have vessel lids which are time-consuming to operate, or which have filter elements such as cloth bags that would not meet current normal filtration standards.

Key Projects

Generally, replacements of station filters is done on an opportunities basis and will be incorporated in other works on the site.

Large filter replacements will be driven by specific needs or perfromance deterioration that requires them to be replaced.

C.21. STATION ANCILLARIES

Several station equipment items are ancillary to the main station asset classes. Ancillary equipment and assets are vital for the operation and security of assets and hence need to be considered separately for the purposes of identifying activities associated with maintenance, replacement and renewal.

Station ancillary components includes the following:

- Land area secured by easement or lease,
- Security fence including gates and locks
- Signage
- Lighting and building(s)

Power, Earthing and Bonding systems containing:

- Mains power supplies
- Solar power supplies
- Switchboards
- Transformers
- Uninterruptible power supply units
- Battery chargers
- Battery bank
- Power system earthing systems (electrodes)

- Pipe work earthing systems (anodes)
- Equipotential bonding
- Earth potential rise mitigation (zinc ribbon)
- Flange insulating kits
- Insulation joint protectors
- Surge diverters

General cabling, cable trenches, cable support systems and junction boxes containing:

- Electrical distribution and systems
- Instrumentation systems
- Safety and alarm systems
- Data/communications systems
- Telecommunications systems

General instrumentation not associated with other asset categories containing:

- Instrumentation Pressure regulators
- Small bore tubing
- Gauges and transducers
- Station inlet and outlet gas process measurements
- Instrumentation Pressure safety valves
- Alarm systems
- In-station piping, above and below ground
- Above ground pipe supports
- Gas detection equipment (not associated with compressor units)

Fleet Overview

Other than the main components described above, stations comprise a considerable amount of ancillary equipment and assets.

Land, Security Fencing (including Gates), Lighting, Signage, and Buildings

In general, security fencing (including gates), signage and buildings are not routinely replaced or renewed. Items are replaced or renewed when issues are identified during maintenance or inspection.

Power, Earthing and Bonding Systems

In general, power, earthing and bonding system components are replaced or renewed when issues are identified during maintenance or inspection.

General Instrumentation not associated with other Asset Categories

In general, field instrumentation will last for many years. A replace-on-failure approach is taken with this kind of equipment, acknowledging that failure of electronic equipment is generally considered random with little or no warning that the failure is about to occur and with no increasing likelihood of failure as the devices age.

General instrumentation on the small to medium sized stations will be reviewed and included in routine calibration and function test maintenance checks.

Cabling, cable support systems and junction boxes are replaced or renewed when issues are discovered during maintenance or inspection.

Piping – Below Ground

In general, below ground piping is not replaced or renewed. At most stations electrodes and ribbon installed for earthing and step-and-touch potential mitigation are now zinc, or zinc coated steel. This greatly reduces the corrosion rate for the buried steel piping (buried steel corrodes 'preferentially' when bonded to buried copper). Zinc earthing does require monitoring and replacement at more frequent intervals as it corrodes preferentially to the steel piping and particularly to steel reinforcing bar in concrete pads. Where the CP levels have been assessed in stations with zinc earthing, they indicate partial protection only.

Condition assessments have been carried out on an ad-hoc basis in conjunction with other excavation works in stations. To date, corrosion has been identified at ground-air interfaces only and mostly on non-pressure piping. These ground air interface inspections are managed through a maintenance management plan.

Piping - Above Ground

In general, above ground piping is not replaced or renewed. Piping is visually inspected specifically for corrosion defects and coating condition at regular intervals (currently 2-yearly). Defects that may constitute an immediate integrity threat receive an engineering assessment and are remediated as soon as practicable post discovery. Recoating of deteriorated coatings and minor corrosion is carried out at stations in priority order - based on the severity and extent of degradation at each station. Temporary hold coats are applied to retard the progression of corrosion, until a station is recoated.

Most of the recoating is 'maintenance painting' where only deteriorated coating, and minor steelwork defects are remediated. Provision is made in the Opex forecast for maintenance painting.

Where recoating of a whole station, or of a major part of a station is required, it is treated as Capex. Provision has been made in the Capex forecast for coating replacement.

Pipe Supports - Above Ground

Pipe supports are categorised and either Maintainable (MT) or Cat I, Cat II or Cat III based on condition identified during regular visual inspection with Cat III being the worst. A risk-based approach to pipe support replacement is utilised to define each year's replacement programme.

There are numerous designs of above ground pipe supports within the stations. Inspections of the supports for corrosion, are visual-type inspections. Depending on support design, generally the larger the pipe diameter the greater the risk of crevice corrosion occurring at the interface between the pipe support and pipe. Although non-destructive techniques have been trialled, currently they do not provide reliable results that can replace the visual inspection.

Gas Detection Equipment (not Associated with Compressor Units)

A review of all gas detection systems has been conducted which confirmed that gas detection installations comply with *AS/NZS 60079*. The report identified there is a mixture of current and obsolete gas detection controllers in service.

Electrical Hazard Management Plan (EHMP) Touch Potential Mitigation

A study on the hazards posed by electrical touch potential is likely to result in modifications being required at station assets. Provision has been made in the expenditure forecast for this activity. The Wellington and Hawkes Bay areas EHMP studies have been completed and the Taranaki study is underway.

Appendix D Asset Fleets

This section contains the specific details of the following asset groups:

D.1 Station Assets

Below is a list of all the stations owned by First Gas:

Station Number	Station Name	Address	Install Year
1000013	Matapu Delivery Point	Skeet Road, Kapuni	1982
1000455	Patea MLV South	Lower Kaharoa Road, Patea	1990
1001051	Kaitoke Compressor Station	Pauri Road, Kaitoke	1984
1060013	Lake Alice Delivery Point	Lake Alice Road, Lake Alice	1980
1160001	Kuku Delivery Point	630 Kuku Beach Road, Horowhenua	1980
1170001	Te Horo Delivery Point	Te Horo Beach Road, Te Horo	1980
1190001	Tawa B Delivery Point	S H 1, Tawa	1997
2001346	Mahoenui Compressor Station	Papakauri Road, Mahoenui	1979
3000188	Pembroke Rd interchange	541R Pembroke Road, Stratford	1976
4000132	Pungarehu 1 Delivery Point	Parihaka Road, Pungarehu	1983
4000439	Frankley Rd Offtake	814 Frankley Road, New Plymouth	1977
4002907	Rotowaro Compressor Station	575 Waikokowai Road, Rotowaro	1981
4010054	Pungarehu 2 Delivery Point	Pungarehu Road, Pungarehu	1983
4020406	Morrinsville Scraper Station	Access via railway yards at Morrinsville	1981
4210102	Te Awamutu North Delivery Point	Factory Road, Te Awamutu	1995
4301075	Wellsford Delivery Point	Worthington Road, Wellsford	1983
4301681	Oakleigh Delivery Point	Whittle Road, Oakleigh	1983
4310001	Waitoki Delivery Point	1341 Kahikatea Flat Road, Waitoki	1998
4400001	Waimauku Delivery Point	S H 16, Waimauku	1985
5000176	Waikeria Delivery Point	Higham Road, Kihikihi	1985
5000788	Kinleith Scraper station	Off Old Taupo Road, Kinleith	1983
5010004	Kinleith No. 1 Delivery Point	Off Old Taupo Road, Kinleith	1983
5100001	Broadlands Delivery Point	Vaile Road, Broadlands	2005
5111001	Broadlands GMS	Vaile Road, Broadlands	2005
6060088	Mokoia Mixing Station	Mokoia Road, Mokoia	2001

Station Number	Station Name	Address	Install Year
6500000	Mokoia Production Station	Mokoia Road, Mokoia	2001
7000433	Te Rehunga Delivery Point	Kumeti Road, Dannevirke	1983
7000892	Balfour Rd Scraper Station	Balfour Road, Ashcott	1983
8000175	Okoroire Delivery Point	73R Somerville Road, Okoroire	1982
8000888	Te Puke Dist. Delivery Point	Washer Road, Te Puke	1984
1000000	Kapuni GTP Compressors	298 Palmer Road, Kapuni	1969
1000001	KGTP North & South & 300 line check	298 Palmer Road, Kapuni	1969
1000062	Okaiawa Offtake	462 Normanby Road, Okaiawa	1982
1000178	Hawera Delivery Point	Fairfield Road, Hawera	1972
1000422	Patea Delivery Point	Victoria Road, Patea	1976
1000442	Patea MLV	Taranaki Road, Patea	1969
1000453	Patea Offtake	Lower Kaharoa Road, Patea	1976
1000619	Waverley Offtake	Lennox Road, Waverley	1976
1000692	Waitotara Delivery Point	270 Waiinu Beach Road, Waitotara	1969
1000954	Mosston Rd MLV	Mosston Road, Wanganui	1969
1000977	Wanganui Delivery Point	5 Karoro Road, Wanganui	1969
1001050	Kaitoke Offtake	Pauri Road, Kaitoke	1977
1001159	Turakina MLV	Turakina Beach Road, Turakina	1969
1001315	Raumai Rd Scraper Station	Raumai Road, Bulls	1969
1001420	Flockhouse Delivery Point	Parewanui Road, Bulls	1985
1001491	Himatangi Offtake	Puke Road, Foxton	1969
1001629	Foxton Delivery Point	80 Foxton Beach Road, Foxton	1971
1001679	Whirokino MLV	32 Matakarapa Road, Foxton	1994
1001702	Oturoa MLV	142 Oturoa Road, Foxton	1969
1001815	Levin Offtake	South of Hokio Beach Road, Levin	1969
1001976	Otaki Beach MLV	85-91 Old Coach Road, Otaki Beach	1969
1002005	Otaki Delivery Point	Unnamed Road next to Otaki River	1981
1002019	Otaki Loop Scraper Station	South of Swamp Road, Otaki	1969
1002163	Waikanae Delivery Point #2	Kauri Road, Waikanae	2015
1002188	Waikanae MLV	S H 1, Waikanae	1969
1002236	Paraparaumu Delivery Point	Valley Road, Paraparaumu	1980

Station Number	Station Name	Address	Install Year
1002423	Pauatahanui No.2 (Horsfields) Delivery Point	Paekakariki Hill Road, Pauatahanui	1973
1002455	Pauatahanui No.1 Delivery Point	209 Paekakariki Hill Road, Pauatahanui	1969
1002532	Waitangarua Delivery Point	7A1 Takapu Road, Porirua	1969
1010016	Okaiawa Delivery Point	Kohiti Road, Okaiawa	1982
1030058	Waverley Delivery Point	Lower Okotuku Road, Moumahaki, Waverley	1976
1040212	Marton Delivery Point	Wings Line, Marton (behind Malting Company)	1983
1050039	Kaitoke # 2 Delivery Point	Pauri Road, Kaitoke	2005
1070244	Kairanga Delivery Point	Gillespies Line, Palmerston North	1972
1070272	Palmerston North Delivery Point	606 Rangitikei Line, Palmerston North	1972
1080068	Longburn Delivery Point	Reserve Road, Longburn	1979
1090052	Levin Delivery Point	Hokio Beach Road, Levin	1978
1100028	Belmont No.1 Delivery Point	Belmont Road, Lower Hutt	1985
1120000	Ammonia Urea No 2 Offtake	Off Compressor at KGTP, Palmer Road, Kapuni	1981
1130051	Oroua Downs Delivery Point	S H 1 near Omanuka Road, Oroua Downs	1983
1130238	Longburn Offtake	Kairanga Bunnythorpe Road, Palmerston North	1983
1130296	Feilding Offtake	Setters Line, Palmerston North	1980
1140087	Feilding Delivery Point	Campbell Road, Feilding	1980
1150001	Kakariki Delivery Point	Cnr Makirikiri Road & Goldings Line, Marton	1984
2000072	Eltham-Kaponga No 1 Offtake	Eltham Road, Kaponga	1981
2000192	Stratford Delivery Point	517R Pembroke Road, Stratford	1978
2000304	Tariki MLV	744A Mountain Road S H 3, Tariki	1981
2000390	Kaimata Tie-In Station	428 Tarata Road, Inglewood	1969
2000520	McKee Mixing Station	Tikorangi Road West, Waitara	1969
2000529	New Plymouth Offtake	177A Ngatimaru Road	1972
2000738	Wai-iti MLV	8 Nopera Road, Waiiti	1981
2001039	Mohakatino Scraper Station	1443 Mokau Road S H 3, Mohakatino	1969
2001606	Mangaotaki MLV	Mangaotaki Road, Piopio	1969
2001841	Oparure MLV	Oparure Road, Te Kuiti	1969
2001941	Waitomo Blind Tap	Golf Road Waitomo	1969

Station Number	Station Name	Address	Install Year
2002128	Cannon Rd MLV	Cannon Road, Otorohanga	1969
2002431	Temple View Delivery Point	Foster Road, Temple View, Hamilton	1969
2002704	Waipuna MLV	Waipuna Road, Rotowaro	1969
2002898	TikoTiko MLV	Tikotiko Road, Glen Murray	1969
2003123	Tuakau South MLV	Highway 22, Tuakau	1969
2003130	Tuakau North MLV	River Road Highway 22, Tuakau	1969
2003168	Tuakau Delivery Point	Bollard Road, Tuakau	1995
2003197	Harrisville Delivery Point	Harrisville Road, Harrisville	1998
2003207	Harrisville Delivery Point #2	353, Harrisville Road, Harrisville	2015
2003394	Papakura Delivery Point	14 Hilldene Road, Papakura	1970
2010041	Inglewood Delivery Point	34 Tarata Road, Inglewood	1975
2030046	Waitara Delivery Point	271 Waitara Road, Waitara	1976
2030105	New Plymouth Delivery Point	195A Connett Road East, Bell Block	1972
2060076	Eltham Delivery Point	North Street, Eltham	1979
2070053	Kaponga Delivery Point	1502 Manaia Road, Kaponga	1981
2080001	Te Kowhai Delivery Point (incl Te Kowhai OT 2002529)	Limmer Road, Hamilton	1983
3000000	KGTP "Maui bypass"	298 Palmer Road, Kapuni	1969
3000062	Eltham-Kaponga No 2 Offtake	Eltham Road, Kaponga	1976
3000243	Derby Rd Compressor Station	Derby Road South, Stratford	1976
3000357	Kaimiro Mixing Station	28 Peters Road, Kaimiro	1994
3010002	TCC Power Station Delivery Point	189 East Road, Stratford	1997
3030086	Stratford PS (2&3) Delivery Point	189 East Road, Stratford	1976
3060000	Kapuni Offtake	Palmer Road, Kapuni	1970
3060034	Kapuni (Lactose) Delivery Point	880 Manaia Road, Kapuni	1970
3070000	Ammonia Urea No 1 Offtake	Palmer Road, Kapuni	1982
3070002	Ammonia Urea Maui/Treated Delivery Point	Palmer Road, Kapuni	1986
3080000	Kaimiro Meter Station	Upland Road, Egmont Village	1984
4000000	Oaonui Outlet MLV	SH 45, Oaonui	1977
4000001	Opunake Delivery Point	S H 45, Oaonui	1984
4000216	Okato No.1 MLV	Oxford Road, Taranaki	1977
4000231	Okato Delivery Point	274 Oxford Road, Okato	1980

Station Number	Station Name	Address	Install Year
4000653	Waitara Valley Offtake	Bertrand Road, Tikorangi	1977
4000668	Tikorangi Mixing Station	184 Ngatimaru Road, Tikorangi	1977
4000901	Pukearuhe MLV	Pukearuhe Road, Waiiti Beach,	1977
4001143	Mokau Compressor station	4282 Mokau Road SH 3, Mokau	1981
4001345	Awakau MLV	Awakau Road, Awakino	1977
4001543	Mahoenui Scraper station	SH 3, Mahoenui	1977
4001778	Mairoa MLV	Mairoa Road, Piopio	1977
4001941	Te Kuiti South Offtake	Mangatea Road, Te Kuiti	1977
4001975	Te Kuitie MLV	Oparure Road, Te Kuiti	1977
4002135	Otorohonga Delivery Point	Waitomo Valley Road, Otorohanga	1982
4002219	Tihiroa South MLV	Kawhia Road (SH 31 & SH 39), Tihiroa	1977
4002220	Tihiroa Scraper Station	Kawhia Road (SH 31 & SH 39), Tihiroa	1977
4002308	Pokuru Offtake	Candy Road, Te Awamutu	1980
4002389	Pirongia MLV	Bird Road, Pirongia	1977
4002652	Te Kowhai MLV	Limmer Road, Hamilton	1977
4002771	Ngaruawahia MLV	Hakarimata Road, Ngaruawahia	1977
4002906	Huntly Offtake	575 Waikokowai Road, Rotowaro	1977
4030087	Huntly Power station DP	Hetherington Road, Huntly	1978
4003092	Glen Murray MLV	Highway 22, Glen Murray	1970
4003260	Pukekawa MLV	Murray Road, Pukekawa	1970
4003310	Whangarata MLV	Whangarata Road, Tuakau	1970
4003419	Glenbrook Offtake	Ingram Road, Pukekohe East	1981
4003503	Drury Delivery Point	211 Waihoehoe Road, Drury	1981
4003530	Papakura East Pressure Red.St.	101 Walker Road, Opaheke	1970
4003566	Clevedon MLV	3602 Papakura-Clevedon Road, Papakura	1981
4003677	Flat Bush Delivery Point	131 Murphys Road, Flat Bush	1997
4003739	Smales Rd MLV	94 Smales Road, East Tamaki	1970
4003770	Waiouru Rd MLV	105 Highbrook Drive, East Tamaki	1970
4003810	Westfield No.1 Delivery Point	453 Mt Wellington Highway, Westfield	1981
4020071	Horotiu Delivery Point	Horotiu Bridge Road, Horotiu	1981
4020321	Kuranui Rd Scraper Station	Kuranui Road, Morrinsville	1981

Station Number	Station Name	Address	Install Year
4020470	Tatuanui Delivery Point	3438 S H 26, Tatuanui	1985
4020500	Waitoa Delivery Point	Wood Road, Waitoa	1985
4050019	Runciman Road Pressure Reducing Station	Runciman Road, Pukekohe East	1984
4050059	Pukekohe Delivery Point	Butcher Road, Pukekohe	1981
4050141	Kingseat Delivery Point	Kingseat Road, Patumahoe	1982
4050214	Waiuku Delivery Point	413A Glenbrook-Waiuku Rd, Glenbrook	2020
4050230	Glenbrook Delivery Point	Mission Bush Road, Glenbrook	1984
4060016	Te Kuiti North Delivery Point	S H 3, Te Kuiti	1982
4070131	Tauwhare Delivery Point	825 Tauwhare Road, Tauwhare	1982
4070227	Cambridge Delivery Point	Bruntwood Road, Cambridge	1982
4080039	Matangi Delivery Point	Tauwhare Road, Matangi	1982
4090014	Kiwitahi Delivery Point	Morrinsville-Walton Road, Morrinsville	1991
4100022	Te Rapa Delivery Point	S H 1, Te Rapa	1999
4120083	Te Kuiti South Delivery Point	S H 30, Waitete Road, Te Kuiti	1982
4130001	Oakura Delivery Point	158 Wairau Road, Oakura	1993
4160001	Ngaruawahia Delivery Point	Brownlee Avenue, Ngaruawahia	1986
4170001	Ramarama Delivery Point	Ararimu Road, Ramarama	1983
4180001	Hunua Delivery Point	31A Hunua Road, Papakura	1970
4190001	Alfriston Delivery Point	109 Phillip Road, Manukau City	1983
4200001	Huntly Delivery Point	Hetherington Road, Huntly	1980
4210000	Te Awamutu North Offtake	Pirongia Road, Pirongia	1995
4220004	Pirongia Delivery Point	Pirongia Road, Pirongia	1995
4230001	Morrinsville Delivery Point	Haig Street, Morrinsville	1981
4240000	Mangorei Delivery Point	Junction Road, Mangorei, New Plymouth	2019
4300015	Southdown Delivery Point	Hugo Johnston Drive, Penrose	1996
4300098	Hillsborough MLV	Hillsborough Road, Hillsborough	1983
4300160	Links Rd MLV	Links Road, Titirangi	1983
4300210	Waikumete Rd MLV	Waikumete Cemetery, Waikumete Road, Glen Eden	1983
4300021	Waikumete Delivery Point	Waikumete Road, Glen Eden	2015
4300355	Henderson Valley Compressor St.	Off 110 Amreins Road, Taupaki	1983
4300356	Henderson Delivery Point	Off 110 Amreins Road, Taupaki	1996

Station Number	Station Name	Address	Install Year
4300672	Kanohi Rd MLV	Hellyer Road, Kaukapakapa	1983
4300903	Kaipara Flats Offtake Station	Woodcocks Road, Kaipara Flats	1983
4301268	Browns Rd MLV	Brown Road, Kaiwaka	1983
4301560	Salle Rd MLV	Salle Road, Ruakaka	1983
4301809	Whangarei Offtake	Otaika Valley Road, Whangarei	1983
4301850	Maungatapere MLV	S H 14, Maungatapere	1983
4320063	Warkworth No.2 Delivery Point	Woodcocks Road, Warkworth	2007
4320100	Warkworth Delivery Point	Woodcocks Road, Warkworth	1983
4330133	Maungaturoto Delivery Point	S H 12, Maungaturoto	1983
4340091	Whangarei Delivery Point	Dyer Street, Whangarei	1983
4350215	Kauri Delivery Point	S H 1, Near Vinegar Hill Road, Kauri	1989
4370069	Marsden Point Delivery Point	Mair Road, Marsden Point	1993
4380001	Bruce McLaren Rd Delivery Point	177 Bruce McLaren Road, Glen Eden	1985
4420025	Otahuhu B Delivery point	Hellabys Road, Otara	1998
5000001	Pokuru Compressor Station	Candy Road, Te Awamutu	1983
5000113	Kihikihi Delivery Point	275 St Leger Road, Kihikihi	1983
5000209	Parawera MLV	Parawera Road, Parawera	1979
5000411	Arapuni West MLV	Arapuni Road, Arapuni	1983
5000416	Arapuni East MLV	Oreipunga Road, Arapuni	1983
5000544	Lichfield Meter Station	404R Lichfield Road, Lichfield	1983
5000594	Lichfield MLV	Pepperill Road, Lichfield	1983
5000720	Tokoroa Delivery Point	Baird Road, Tokoroa	1983
5000789	Kinleith No 2 Delivery Point	Off Old Taupo Road, Kinleith	1980
5000938	Rahui Rd MLV	Rahui Road (private forestry road), Kinleith	1979
5001091	Nicholson Rd MLV	450 Nicholson Road, Ngakuru	1985
5001215	Earthquake Flat Rd MLV	226 Earthquake Flat Road, Rotorua	1981
5001241	Rotorua/Taupo Offtake Station	Earthquake Flat Road, Rotorua	1985
5001401	Ash Pit Rd MLV	Ash Pit Road, Rerewhakaaitu	1985
5001555	Ngamotu Rd MLV	Ngamotu Road	1985
5001663	McKee Rd MLV	McKee Road (private forestry road), Matahina	1985
5001820	Kawerau Delivery Point	East Bank Road, Kawerau	1985

Station Number	Station Name	Address	Install Year
5020093	Te Teko Delivery Point	51 Tahuna Road, Te Teko	1985
5020192	Edgecumbe Delivery Point	492 Awakeri Road, Edgecumbe	1982
5030180	Rotorua Delivery Point	S H 5, Rotorua	1984
5040182	Reporoa Delivery Point	S H 5, Reporoa	1984
5050001	Kawerau Compressor Station	Hydro Road, off Matata East Road	1985
5050280	Ruatoki North MLV	Rewarau Road, Ruatoki	1985
5050458	Burnetts Rd MLV	Burnett Road, Nukuhou North	1985
5050665	Opotiki MLV	Pile Road, Opotiki	1985
5050928	Oponae Scraper Station	S H 2, Waioeka	1985
5051165	Trafford Hill MLV	S H 2, Waioeka	1985
5051401	Olliver Rd MLV	Oliver Road, Matawai	1985
5051641	Waihuka MLV	Waihuka Road, Te Karaka	1985
5051840	Kaiteratahi Scraper Station	S H 2, Kaitaratahi	1985
5052013	Gisborne Delivery Point	566 Back Ormond Road, Gisborne	1985
5060044	Opotiki Delivery Point	Factory Road, Opotiki	1984
5070137	Whakatane Delivery Point	64 Mill Road, Whakatane	1986
5080191	Broadlands MLV	Broadlands Road, Reporoa	1987
5080389	Taupo Delivery Point	269 Rakaunui Road, Taupo	1987
5090005	Lichfield Dairy No.1 Delivery Point	S H 1, Lichfield	1995
6050140	Paekakariki North MLV	Off S H 1, Paekakariki	1985
7000170	Saddle Rd MLV	Saddle Road, Ashhurst	1983
7000277	Foley Rd Offtake	Foley Road, Woodville	1983
7000503	Dannevirke Delivery Point	Rule Road, Dannevirke	1983
7000588	Tataramoa MLV	Tataramoa Road, Matamau	1983
7000844	Takapau Delivery Point	Nancy Street, S H 2, Takapau	1983
7001195	Knights Rd MLV	2752 Raukawa Road, Hastings	1983
7001469	Mangaroa Delivery Point	Mangaroa Road, Mangaroa	1983
7001482	Bridge Pa MLV	Maraekakaho Road, Hastings	1983
7001531	Hastings Delivery Point	Karamu Road South, Hastings	1983
7020212	Pahiatua Delivery Point	Mangahao Road, Pahiatua	1984
7030004	Mangatainoka Delivery Point	Kohinui Road, Mangatainoka	1984
7050001	Ashhurst Delivery Point	Saddle Road, Ashhurst	1990

Station Number	Station Name	Address	Install Year
8000044	Putaruru Delivery Point	Bridge Street, S H 1, Putaruru	1981
8000141	Hetherington Rd MLV	143R Hetherington Road, Matamata	1984
8000343	Kaimai Summit Scraper Station	3159 S H 29, Kaimai	1984
8000603	Pyes Pa MLV	Bathurst Crescent, Tauranga	1982
8000780	Mt Manganui Offtake station	172 L Kairua Road, Mt Maunganui	1984
8000805	Papamoa Delivery Point	S H 2, Te Puke	1984
8020020	Tirau Delivery Point	Okoroire Road, Tirau	1981
8030079	Tauranga Delivery Point	116B Birch Avenue, Tauranga	1982
8040049	Mt Maunganui Delivery Point	Truman Road, Mt Maunganui	1984
8050083	Rangiuru Delivery Point	S H 2, Te Puke	1984
8070001	Pyes Pa Delivery Point	Lakes Boulevard, Pyes Pa, Tauranga	2007

D.2. PIPELINE ASSETS

Pipe #	Pipe Name	Length (km)	MAOP (kPa)	Date Commissioned	Outside Diam. (mm)	Nominal Bore (mm)	Wall Thick (mm)	Material Grade	Coating System
100	Kapuni - Waitangirua	247.130	8620	Jan-68	219	200	5.56	API 5L X42	Coal Tar Enamel
100A	McKays Crossing Realignment	0.982	8620	Jan-04	219	200	5.56	API 5L X52	Extruded Polyethylene - High Density (HDPE)
100B	Ohau River Realignment	0.321	8620	Mar-07	219	200	8.18	API 5L X46	Dual FBE
100C	Whitby Realignment	0.427	8620	Nov-07	219	200	8.18	API 5L X42	Dual FBE
100D	McKays to Peka Peka Realignment	1.433	8620	May-15	219	200	8.18	API 5L X42	3 Layer Polyethylene
100E	Whirokino Trestle Bridge Realignment	0.978	8620	May-18	219	200	6.35	API 5L X52 PSL2	2 Layer FBE
100F	Duck Creek Realignment	0.548	8620	Sep-17	219	200	6.35	API 5L X46	3 Layer Polyethylene
100G	Endeavour Drive Realignment	0.373	8620	Sep-17	212.8	200	6.4	API 5L Gr X56 HFW	2 Layer FBE
100H	Paekakariki - Paekakariki, HHD section Realignment	0.736	8620	Jul-17	212.8	200	6.4	API 5L Gr X56 HFW	2 Layer FBE, 3 Layer Polyethylene
100I	Pig Pen Realignment	0.073	8620	Sep-17	212.8	200	6.4	API 5L Gr X56 HFW	2 Layer FBE
100J	Waitangirua Link Road Realignment	0.194	8620	Apr-19	212.8	200	6.4	API 5L Gr X56	3 Layer Polyethylene
101	Okaiawa Lateral	1.665	8620	Jan-77	60	50	3.20	API 5L GrB	Extruded Polyethylene - Yellow
103	Waverley Lateral	5.793	8620	Jan-75	60	50	3.20	API 5L GrB	Coal Tar Enamel
104	Marton Lateral	21.118	8620	Jan-80	114	100	4.78	API 5L GrB	Extruded Polyethylene - Yellow
105	Kaitoke Lateral	3.682	8620	Jan-78	60	50	3.20	API 5L GrB	Extruded Polyethylene - Yellow
106	Lake Alice Lateral	1.356	8620	Jan-80	60	50	3.18	API 5L GrB	Extruded Polyethylene - Yellow
107	Himatangi - Palmerston North	27.155	8620	Jan-69	89	80	3.18	API 5L GrB	Coal Tar Enamel
108	Longburn Lateral	6.715	8620	Jan-74	89	80	3.20	API 5L GrB	Coal Tar Enamel
109	Levin Lateral	5.240	8620	Jan-68	89	80	3.20	API 5L GrB	Coal Tar Enamel

Pipe #	Pipe Name	Length (km)	MAOP (kPa)	Date Commissioned	Outside Diam. (mm)	Nominal Bore (mm)	Wall Thick (mm)	Material Grade	Coating System
110	Waitangirua - Belmont	2.598	8620	Jan-69	219	200	7.90	API 5L GrB	Coal Tar Enamel
110A	Waitangirua Realignment	0.222	8620	Feb-18	212.8	200	6.4	API 5L Gr X56	2 Layer FBE
111	Waitangirua - Tawa	7.308	8620	Jan-69	219	200	5.56	API 5L X42	Coal Tar Enamel
111A	Cannons Creek Realignment	0.954	8620	Jul-17	212.8	200	6.4	API 5L Gr X56 HFW	3 Layer Polyethylene
112	Ammonia-Urea Lateral	0.502	5200	Jan-81	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow
113	Himatangi - Feilding Stage I Dup	5.947	8620	Jan-80	168	150	7.11	API 5L GrB	Coal Tar Enamel
113A	Himatangi - Feilding Stage II	23.652	8620	Jan-80	168	150	7.11	API 5L GrB	Coal Tar Enamel
114	Feilding Lateral	8.720	8620	Jan-80	89	80	3.18	API 5L GrB	Extruded Polyethylene - Yellow
115	Kakariki Lateral	0.011	8620	Jan-84	60	50	3.20	API 5L GrB	Extruded Polyethylene
116	Kuku Lateral	0.062	8620	Jan-80	60	50	3.90	API 5L GrB	Extruded Polyethylene - Yellow
117	Te Horo Lateral	0.185	8620	Jan-80	60	50	3.90	API 5L GrB	Extruded Polyethylene - Yellow
119	Tawa B Lateral	0.020	8620	Nov-97	60	50	3.90	API 5L GrB	Polyken
120	Tawa B No 2	0.032	8620	Mar-99	114	100	6.02	A106 GR B	Polyken
200	Kapuni - Papakura	339.941	8620	Jan-68	219	200	5.60	API 5L X42	Coal Tar Enamel
200A	White Cliffs Realignment	1.352	8620	Apr-78	219	200	5.60	API 5L X42	Coal Tar Enamel
200B	Rotowaro Tie In	0.468	8620	Nov-83	219	200	5.60	API 5L X42	Coal Tar Enamel
200C	Lincoln Road Realignment	0.996	8620	Jan-85	219	200	5.60	API 5L X42	Coal Tar Enamel
200D	Twin Creeks Realignment	1.028	8620	Oct-06	219	200	8.20	API 5L X42	Dual FBE - Naprock
200E	Beach Road Realignment	0.143	8620	Nov-14	219	200	8.18	API 5L X42	3 Layer Polyethylene
201	Inglewood Lateral	4.246	8620	Jan-74	89	80	3.17	API 5L GrB	Extruded Polyethylene - Yellow
203	New Plymouth Lateral	10.648	8620	Jan-69	89	80	3.18	API 5L GrB	Coal Tar Enamel
203A	Waiongana River Realignment	0.187	8620	Nov-11	89	80	7.62	API 5L X42	Trilaminate HDPE (3LP)

Pipe #	Pipe Name	Length (km)	MAOP (kPa)	Date Commissioned	Outside Diam. (mm)	Nominal Bore (mm)	Wall Thick (mm)	Material Grade	Coating System
203B	Connett Road East Realignment	0.801	8620	Sep-13	89	80	7.62	API 5L GrB	Trilaminate HDPE (3LP)
206	Eltham Lateral	7.740	8620	Jan-77	89	80	3.17	API 5L GrB	Extruded Polyethylene - Green
207	Kaponga Lateral	5.374	8620	Jan-81	89	80	3.20	API 5L GrB	Extruded Polyethylene - Yellow
208	Te Kowhai Lateral	0.086	8620	Apr-99	219	200	8.18	A106 GR B	Extruded Polyethylene
209	Pokuru Connection	0.200	8620	Dec-99	219	200	7.80	API 5L GrB	Extruded Polyethylene - Yellow
300	Kapuni - Frankley Road	46.509	6620	Jan-74	508	500	6.35	API 5L X60	Coal Tar Enamel
301	Tar Combined Cycle Gas Supply	0.196	6620	Feb-97	268	250	6.40	API 5L X42	Extruded Polyethylene - Yellow
302	Tar Combined Cycle Gas Supply	0.196	8620	Feb-97	268	250	9.40	API 5L X42	Extruded Polyethylene - Yellow
303	Stratford Lateral	8.638	6620	Jan-74	508	500	6.35	API 5L X60	Coal Tar Enamel
306	Kapuni Dist Lateral (Section I)	1.468	8620	Mar-70	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow
306A	Kapuni Dist Lateral (Section II)	1.347	8620	Mar-70	219	200	5.60	API 5L X42	Asphalt Enamel
306B	Kapuni Dist Lateral (Section III)	0.518	8620	Mar-70	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow
307	Ammonia-Urea Lateral	0.172	8620	Jan-82	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow
308	Kaimiro Lateral	3.361	8620	Jan-84	114	100	4.78	API 5L GrB	Extruded Polyethylene - Yellow
309	KGTP Export to 300 Line	0.244	6620	Apr-05	168	150	7.10	API 5L GrB	3 Layer Polyethylene - Orange
400	Maui - Oaonui to Frankley Rd	46.892	7240	Jul-77	864	850	10.31	API X65	Coal Tar Enamel
400A	Maui - Frankley Rd - Huntly offtake	246.68	7240	Jul-77	762	750	9	API X65	Coal Tar Enamel
400B	Huntly OT - Mill Rd Pukekohe	48.615	8620	Jan-81	356	350	5.60	API 5L X60	Coal Tar Enamel
400C	Pukekohe - Papakura East PRS	13.830	8620	Jan-81	356	350	5.60	API 5L X60	Coal Tar Enamel
400D	Papakura - Boundary Rd	0.452	6620	Jan-81	356	350	5.60	API 5L X60	Coal Tar Enamel

Pipe #	Pipe Name	Length (km)	MAOP (kPa)	Date Commissioned	Outside Diam. (mm)	Nominal Bore (mm)	Wall Thick (mm)	Material Grade	Coating System
400E	Papakura - Westfield	27.532	6620	Jan-81	356	350	11.90	API 5L X52	Coal Tar Enamel
400F	Westfield - Southdown	1.724	6620	May-09	356	350	9.52	API 5L X52	3 Layer Polyethylene - Orange
401	Pungarehu Lateral	5.574	7140	Jan-80	60	50	3.90	API 5L GrB	Extruded Polyethylene - Yellow
402	Te Kowhai - Horotiu East	7.285	8620	Jan-81	168	150	4.80	API 5L GrB	Extruded Polyethylene - Yellow
402A	Horotiu East - Kuranui Rd	24.285	8620	Jan-81	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow
402B	Kuranui Rd - Morrinsville	8.290	8620	Jan-81	168	150	4.80	API 5L GrB	Extruded Polyethylene - Yellow
402C	Morrinsville - Tatuanui	6.461	8620	Jan-85	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow
402D	Tatuanui - Waitoa	3.259	8620	Jan-85	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow
402E	Waikato River Realignment	0.196	8620	Jan-01	168	150	7.11	API 5L GrB	Extruded Polyethylene - Yellow
402F	Ngaruawahia Realignment	0.681	8620	Jan-11	114	100	8.56	API 5L X52	3 Layer Polyethylene-Yellow 3.2mm thick
403	Huntly lateral	8.720	4960	Jan-77	406	400	6.35	API 5L X60	Coal Tar Enamel
404	New Plymouth Power Station	9.604	4960	Jan-74	508	500	6.35	API 5L X60	Coal Tar Enamel
405	Glenbrook Lateral	23.123	8620	Jan-84	168	150	7.11	API 5L GrB	DCTW and Coal Tar
406	Te Kuiti North Lateral	1.563	8620	Jan-82	60	50	3.20	API 5L GrB	Extruded Polyethylene - Yellow
407	Cambridge Lateral	0.107	8620	Jan-82	114	100	4.78	API 5L GrB	Extruded Polyethylene - Yellow
407A	Cambridge Lateral	22.586	8620	Jan-82	89	80	3.17	API 5L GrB	Extruded Polyethylene - Yellow
408	Matangi Lateral	3.845	8620	Jan-82	60	50	3.18	API 5L GrB	Extruded Polyethylene - Yellow
409	Kiwitahi Lateral	1.395	8620	May-90	89	80	3.96	API 5L GrB	Extruded Polyethylene - Yellow
410	Te Rapa Lateral	1.311	8620	Feb-99	219	200	8.20	API 5L GrB	Extruded Polyethylene - Yellow

Pipe #	Pipe Name	Length (km)	MAOP (kPa)	Date Commissioned	Outside Diam. (mm)	Nominal Bore (mm)	Wall Thick (mm)	Material Grade	Coating System
412	Te Kuiti South Lateral	8.372	8620	Jan-83	89	80	3.20	API 5L GrB	Extruded Polyethylene - Yellow
412A	Te Kuiti South Realignment	0.128	8620	May-86	89	80	3.20	API 5L GrB	Extruded Polyethylene - Yellow
413	Oakura Lateral	0.025	8620	Jan-93	60	50	3.90	API 5L GrB	Extruded Polyethylene - Yellow
416	Ngaruawahia Lateral	0.100	8620	Apr-85	60	50	3.90	API 5L GrB	Extruded Polyethylene - Yellow
417	Ramarama Lateral	0.078	8620	Jan-83	60	50	3.20	API 5L GrB	Extruded Polyethylene - Yellow
418	Papakura Lateral	0.074	6620	Jan-83	60	50	3.20	API 5L GrB	Extruded Polyethylene - Yellow
419	Alfriston Lateral	0.059	6620	Jan-83	60	50	3.20	API 5L GrB	Extruded Polyethylene - Yellow
420	Huntly Town Lateral	0.029	4960	Dec-80	60	50	3.20	API 5L GrB	Extruded Polyethylene - Yellow
421	Te Awamutu North Lateral	10.248	8620	Jan-95	168	150	6.40	API 5L GrB	Extruded Polyethylene - Yellow
422	Pirongia Lateral	0.380	8620	Jan-95	168	150	6.40	API 5L GrB	Extruded Polyethylene - Yellow
430	Westfield - Henderson Vly CS	35.074	6620	Jan-82	219	200	6.40	API 5L X42	Extruded Polyethylene - Yellow
430B	Henderson Vly CS - Ruakaka	120.473	8620	Jan-82	168	150	4.80	API 5L GrB	Extruded Polyethylene - Yellow
430C	Ruakaka - Maungatapere	29.020	8620	Jan-82	168	150	5.60	API 5L GrB	Extruded Polyethylene - Yellow
430D	Southdown Realignment	0.306	6620	Dec-95	219	200	6.40	API 5L X42	HDPE
430E	Onehunga Realignment	0.229	8620	Oct-09	219	200	6.35	API 5L X42	HDPE (17mm thick) Yellow Jacket
430F	Mt Wellington Rail	0.048	6620	Aug-10	219	200	6.35	API 5L X42	Trilaminate (2.5mm thick) yellow
431	Waitoki Lateral	0.008	8620	Nov-98	114	100	5.50	API 5L GrB	Extruded Polyethylene - Yellow
432	Kaipara Flats - Warkworth	6.391	8620	Jan-83	60	50	3.18	API 5L GrB	Extruded Polyethylene - Yellow

Pipe #	Pipe Name	Length (km)	MAOP (kPa)	Date Commissioned	Outside Diam. (mm)	Nominal Bore (mm)	Wall Thick (mm)	Material Grade	Coating System
433	Maungaturoto Lateral	13.295	8620	Jan-83	89	80	3.18	API 5L GrB	Extruded Polyethylene - Yellow
434	Whangarei Lateral	9.156	8620	Jan-83	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow
435	Kauri Lateral	21.502	8620	Jan-88	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow
437	Marsden Point Lateral	6.906	8620	Jan-93	168	150	4.80	API 5L GrB	Extruded Polyethylene - Yellow
438	Bruce McLaren Lateral	0.090	6620	Mar-85	60	50	3.20	API 5L GrB	Extruded Polyethylene
440	Waimauku Lateral	0.028	8620	Sep-85	60	50	3.90	API 5L GrB	Extruded Polyethylene - Yellow
441	Smales Rd - Waiouru Rd Loop	3.107	6620	Jan-98	356	350	11.90	API 5L X65	Polyken - Plant Applied (Synergy)
442	Otara Lateral	2.410	6620	Jan-98	323	300	11.10	API 5L X65	Extruded Polyethylene - Yellow
443	ETCART Extension	0.488	6620	Jan-98	356	350	11.90	API 5L X65	Polyken - Plant Applied (Synergy)
444	Te Rapa Co-Gen	0.515	4960	Feb-99	273	250	7.80	API 5L GrB	Polyken - YGIII
500	Te Awamutu - Kinleith	78.880	8620	Jan-82	324	300	5.16	API 5L X60	Coal Tar Enamel
500A	Kinleith - Kawerau	103.160	8620	Jan-82	219	200	5.56	API 5L GrB	Coal Tar Enamel
501	Kinleith Lateral	0.140	8620	Jan-82	324	300	5.20	API 5L X60	Polyken
502	Edgecumbe Lateral	18.762	8620	Jan-82	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow
502A	Edgecumbe Realignment	0.502	8620	Jun-11	114	100	8.60	API FLB PSL1	3 Layer Polyethylene - Yellow
503	Rotorua Lateral	16.830	8620	Jan-83	89	80	3.96	API 5L GrB	Fusion Bonded Epoxy
503A	Rotorua - Tumunui Deviation	1.113	8620	Mar-97	89	80	5.40	API 5L GrB	Extruded Polyethylene - Yellow
504	Reporoa Lateral	18.229	8620	Jan-84	114	100	4.78	API 5L GrB	Extruded Polyethylene - Yellow
505	Kawerau - Gisborne	183.749	8620	Jan-84	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow

Pipe #	Pipe Name	Length (km)	MAOP (kPa)	Date Commissioned	Outside Diam. (mm)	Nominal Bore (mm)	Wall Thick (mm)	Material Grade	Coating System
505A	Waipaoa River - Gisborne	17.285	8620	Jan-84	219	200	5.60	API 5L GrB	Extruded Polyethylene - Yellow
505B	Waikohu River Realignment	0.249	8620	May-09	114	100	8.56	API 5L GRB	3 Layer Polyethylene - Orange
506	Opotiki Lateral	4.439	8620	Jan-84	89	80	3.96	API 5L GrB	Extruded Polyethylene - Yellow
507	Whakatane Lateral	13.200	8620	Jan-86	114	100	4.78	API 5L GrB	Extruded Polyethylene - Yellow
507A	Edgecumbe Realignment	0.213	8620	Jun-11	114	100	8.60	API 5LB PSL1	3 Layer Polyethylene - Yellow
508	Taupo Lateral	38.910	8620	Jan-87	168	150	4.80	API 5L GrB	Extruded Polyethylene - Yellow
509	Lichfield Lateral	0.520	8620	Jan-95	89	80	4.00	API 5L GrB	Extruded Polyethylene - Yellow
510	Broadlands Lateral	0.022	8620	Apr-05	60	50	3.91	A106 GR B	Polyken
601	Waikanae - Te Horo Loop	15.576	8620	Jan-81	324	300	5.16	API 5L X60	Coal Tar Enamel
601A	McKays to Peka Peka Realignment	1.433	8620	Apr-15	324	300	7.90	API 5L X60	3 Layer Polyethylene
602	Wanganui Kaitoke Loop	9.936	8620	Jan-84	324	300	7.90	API 5L X60	Unknown
603	Patea - Waitotara Loop	25.084	8620	Jan-84	324	300	7.90	API 5L X52	Extruded Polyethylene - Yellow
604	Wanganui Mosston Loop (II)	26.933	8620	Jan-83	324	300	7.92	API 5L X52	Extruded Polyethylene - Yellow
605	Waikanae - Belmont Loop	37.922	8620	Jan-85	324	300	6.30	API 5L X60	Fusion Bonded Epoxy
605A	Horse Paddock Realignment	0.153	8620	Mar-18	315.84	300	7.92	Gr X60 HFW PSL2	2 Layer FBE
605B	Golf Course Realignment	0.764	8620	Mar-19	315.84	300	7.92	Gr X60 HFW PSL2	2 Layer FBE
605C	Flightys Zig Realignment	0.249	8620	Dec-17	315.84	300	7.92	Gr X60 HFW PSL2	3 Layer Polyethylene
605D	Flightys Zag Realignment	0.487	8620	Dec-19	315.84	300	7.92	Gr X60 HFW PSL2	2 Layer FBE
605E	Pauatahanui (Lanes Flat) Realignment	0.363	8620	Jul-17	315.84	300	7.92	Gr X60 HFW PSL2	3 Layer Polyethylene
605F	Bradey Road Realignment	0.122	8620	Dec-17	315.84	300	7.92	Gr X60 HFW PSL2	3 Layer Polyethylene

Pipe #	Pipe Name	Length (km)	MAOP (kPa)	Date Commissioned	Outside Diam. (mm)	Nominal Bore (mm)	Wall Thick (mm)	Material Grade	Coating System
605G	Tomo & Pines Realignment	0.251	8620	Dec-17	315.84	300	7.92	Gr X60 HFW PSL2	3 Layer Polyethylene
606	Hawera - Patea Loop	26.300	8620	Jan-86	323	300	5.16	API 5L X60	Extruded Polyethylene - Yellow
607	Foxton Loop	1.839	8620	Jan-94	323	300	5.60	API 5L X52	Extruded Polyethylene - Yellow
700	Feilding OT - Hastings (SH 2)	150.6474	8620	Jan-82	219	200	5.56	API 5L GrB	Extruded Polyethylene - Yellow
700A	SH 2 - Hastings	1.984	8620	Jan-82	219	200	9.50	API 5L X52	Extruded Polyethylene - Yellow
700B	Pohangina Realignment	0.439	8620	May-04	219	200	8.18	API 5L X42	Extruded Polyethylene - Yellow
700C	Hawkes Bay Expressway Realignment	0.175	8620	Apr-10	219	200	8.56	API 5L X52	Polyurea k5, 2000µm min thickness
702	Pahiatua Lateral	21.222	8620	Jan-83	114	100	4.78	API 5L GrB	Extruded Polyethylene - Yellow
703	Mangatainoka Lateral	0.433	8620	Jan-83	60	50	3.18	API 5L GrB	Extruded Polyethylene - Yellow
705	Ashhurst Lateral	0.037	8620	Jan-90	60	50	3.20	API 5L GrB	Extruded Polyethylene - Yellow
715	Ahuroa-Stratford PS	8.571	8620	Dic-13	457	450	12.7	API 5L X52 PSL2	3-Layer Polyethylene (3LPE)
800	Lichfield - Tirau	14.099	8620	Jan-80	168	150	7.10	API 5L GrB	Extruded Polyethylene - Yellow
800A	Tirau - Kaimai Summit	20.254	8620	Jan-80	168	150	4.80	API 5L GrB	Extruded Polyethylene - Yellow
800B	Kaimai Summit - Te Puke	52.367	8620	Jan-80	114	100	4.80	API 5L GrB	Extruded Polyethylene - Yellow
800C	Pyes Pa Realignment	0.967	8620	Sep-06	114	100	8.56	API 5L X42	3 Layer Polyethylene
800D	Pyes Pa Realignment 2	0.216	8620	May-09	114	100	8.56	API 5L X42	3 Layer Polyethylene 1.7mm thick
802	Tirau Lateral	1.996	8620	Jan-80	89	80	3.18	API 5L GrB	Extruded Polyethylene - Yellow
803	Tauranga Lateral (Sect I)	1.185	8620	Jun-83	89	80	3.20	API 5L GrB	Extruded Polyethylene - Yellow
803A	Tauranga Lateral (Sect II)	2.964	8620	Jun-83	60	50	3.20	API 5L GrB	Extruded Polyethylene - Yellow

Pipe #	Pipe Name	Length (km)	MAOP (kPa)	Date Commissioned	Outside Diam. (mm)	Nominal Bore (mm)	Wall Thick (mm)	Material Grade	Coating System
803B	Tauranga Lateral (Section B)	1.233	8620	Oct-99	114	100	6.02	API 5L GrB	2 Layer Extruded Polyethylene - High Density (Yellow Jacket)
803C	Tauranga Lat (Pyes Pa Realignment)	1.604	8620	Mar-06	114	100	8.56	API 5L X42	3 Layer Polyethylene
804	Mt Maunganui Lateral	4.953	8620	Jan-80	89	80	3.20	API 5L GrB	Extruded Polyethylene - Yellow
804A	Te Maunga Realignment	0.300	8620	Jan-95	89	80	3.20	API 5L GrB	Extruded polyethylene - Yellow
805	Rangiuru Lateral	8.307	8620	Jan-80	89	80	3.20	API 5L GrB	Extruded Polyethylene - Yellow
807	Pyes Pa Lateral	0.035	8620	Apr-07	114	100	8.56	API 5L X42	Extruded Polyethylene - Yellow

D.3. Special Crossings

Line	Meterage	Type	Location	Year Commissioned
100	168758	Aerial Crossing	Manawatu River Bridge	1968
100	236300	Aerial Crossing	Gibbs Fault	1968
104	19604	Aerial Crossing	Tutaenui Stream Bridge	1980
200	81452	Aerial Crossing	Gilbert Stream	1968
200	145013	Aerial Crossing	Waipapa Stream	1968
200	312443	Aerial Crossing	Waikato River	1968
201	362	Aerial Crossing	Maketawa Stream	1974
201	2249	Aerial Crossing	Ngatoro Stream	1974
300	12764	Aerial Crossing	Waingongoro Tributary	1974
300	15075	Aerial Crossing	Waingongoro River	1974
300	15274	Aerial Crossing	Waingongoro Tributary	1974
300	15422	Aerial Crossing	Waingongoro Tributary	1974
300	16984	Aerial Crossing	Paetahi Stream	1974
300	17407	Aerial Crossing	Konini Stream	1974
300	17908	Aerial Crossing	Patea River	1974
300	20706	Aerial Crossing	Kahouri Stream	1974
300	29662	Aerial Crossing	Piakau Tributary	1974
300	30131	Aerial Crossing	Piakau Stream	1974
300	34263	Aerial Crossing	Waiongana Stream	1974
300	37098	Aerial Crossing	Kai Auahi Tributary	1974
300	37450	Aerial Crossing	Kai Auahi Stream	1974
300	38435	Aerial Crossing	Mangakotukutuku Stream	1974
300	39170	Aerial Crossing	Mangawarawara Stream	1974
300	41844	Aerial Crossing	Mangorei Stream	1974
300	44470	Aerial Crossing	Te Henui Stream	1974
400B	327471	Aerial Crossing	Waikato River	1981
500	41225	Aerial Crossing	Waikato River	1982
500	41360	Aerial Crossing	Arapuni Dam	1982
605	18538	Aerial Crossing	Gibbs Fault	1985
606	13932	Aerial Crossing	Waikaikai Stream	1986
100	1264	Cased crossing	Skeet Road	1968

Line	Meterage	Type	Location	Year Commissioned
100	14058	Cased crossing	South Road SH 45	1968
100	95337	Cased crossing	Mosston Rd	1968
100	96071	Cased crossing	Puriri Street	1968
100	97435	Cased crossing	Castlecliff Industrial Line & Heads Road	1968
100	144701	Cased crossing	Tangimoana - Longburn Road	1968
100	153906	Cased crossing	Himitangi Beach Rd	1968
100	162971	Cased crossing	Foxton Beach Rd	1968
100	198849	Cased crossing	Tasman Road	1968
100	199660	Cased crossing	Rangiuru Road	1968
100	215283	Cased crossing	Te Moana Road	1968
100	217927	Cased crossing	North Island Main Trunk	1968
100	218525	Cased crossing	SH 1	1968
100	230895	Cased crossing	SH 1 (Paraparaumu-Paekakariki)	1968
100	231889	Cased crossing	SH 1	1968
104	14285	Cased crossing	SH 3	1980
104	21070	Cased crossing	North Island Main Trunk, Marton	1980
107	5129	Cased crossing	SH 1	1969
107	20074	Cased crossing	Rongotea Road	1969
107	27105	Cased crossing	Rangitikei Line SH 3	1969
108	4954	Cased crossing	No 1 Line Longburn	1974
108	5346	Cased crossing	Longburn Rongotea Road	1974
108	6306	Cased crossing	North Island Main Trunk	1974
111	7392	Cased crossing	Motorway Off-Ramp SH 1, Tawa	1969
111	7433	Cased crossing	Johnsonville Porirua Motorway SH 1, Tawa	1969
111	7590	Cased crossing	Takapu Road, Tawa	1969
112	116	Cased crossing	Palmer Road	1981
113	5135	Cased crossing	SH 1	1980
113	26302	Cased crossing	SH 3	1980
114	7719	Cased crossing	Camerons Line (SH 54), Feilding	1980

Line	Meterage	Type	Location	Year Commissioned
114	8644	Cased crossing	SH 54 & NIMT Railway, Feilding	1980
200	855	Cased crossing	Kapuni Branch	1968
200	7219	Cased crossing	Eltham Road	1968
200	14402	Cased crossing	Opunake Road	1968
200	30536	Cased crossing	Marton-New Plymouth Line & SH 3	1968
200	59565	Cased crossing	Inland North Road	1968
200	63445	Cased crossing	Kaipikari Road	1968
200	66691	Cased crossing	SH 3	1968
200	72035	Cased crossing	Pukearuhe Road	1968
200	98678	Cased crossing	Mokau Road SH 3	1968
200	103177	Cased crossing	Mokau Road SH 3	1968
200	106746	Cased crossing	SH 3	1968
200	115302	Cased crossing	SH 3	1968
200	129245	Cased crossing	SH 3	1968
200	131157	Cased crossing	SH 3	1968
200	132487	Cased crossing	SH 3	1968
200	141647	Cased crossing	SH 3	1968
200	191980	Cased crossing	Waitomo Caves Road SH 37	1968
200	210752	Cased crossing	Kawhia Road SH 31	1968
200	224127	Cased crossing	Pirongia Road	1968
200	231061	Cased crossing	Kakaramea Road SH 39	1968
200	232995	Cased crossing	Kakaramea Road SH 39	1968
200	239592	Cased crossing	Tuhikaramea Road	1968
200	247216	Cased crossing	Whatawhata Road SH 23	1968
200	274234	Cased crossing	Waikokowai Road	1968
200	274676	Cased crossing	Rotowaro Industrial Line	1968
200	294249	Cased crossing	SH 22	1968
200	312211	Cased crossing	Highway 22	1968
200	315935	Cased crossing	Whangarata Road	1968
200	316785	Cased crossing	Bollard Road	1968
200	317214	Cased crossing	North Island Main Trunk	1968

Line	Meterage	Type	Location	Year Commissioned
200	319714	Cased crossing	Harrisville Road	1968
200	322401	Cased crossing	Harrisville Road	1968
200	324656	Cased crossing	Pukekohe East Road	1968
200	327626	Cased crossing	Runciman Road	1968
200	333355	Cased crossing	North Island Main Trunk	1968
200	333801	Cased crossing	Karaka Road (SH 22), Drury	1968
203	6640	Cased crossing	Waitara Industrial Line	1969
203	7649	Cased crossing	Mountain Road SH 3A	1969
207	4	Cased crossing	Eltham Road	1981
300	468	Cased crossing	Kapuni Branch Railway	1974
300	6135	Cased crossing	Eltham Road	1974
300	14053	Cased crossing	Opunake Road	1974
303	4905	Cased crossing	Marton-New Plymouth Line & SH 3	1974
306	130	Cased crossing	Palmer Road, Kapuni	1970
400	3500	Aerial Crossing	Oaoiti Stream	1977
400	25800	Aerial Crossing	Katikara Stream	1977
400	26600	Aerial Crossing	Katikara Tributary	1977
400	33000	Aerial Crossing	Lucys Gully	1977
400	38500	Aerial Crossing	Tapuae Trib	1977
400	40600	Aerial Crossing	Hurford Road- Creek	1977
400	49700	Aerial Crossing	Junction Road Water-Coarse	1977
400	59600	Aerial Crossing	Waiongana Stream	1977
400	94500	Aerial Crossing	Waikaramarama Stream 1	1977
400	95100	Aerial Crossing	Waikaramarama Stream 2	1977
400	95800	Aerial Crossing	Gilbert Stream	1977
400	100900	Aerial Crossing	Waipingau Stream	1977
400	101100	Aerial Crossing	Waipingau Trib	1977
400	102400	Aerial Crossing	Waikororoa Stream	1977
400	106000	Aerial Crossing	Waikiekie Stream	1977
400	126100	Aerial Crossing	Bexley Gully No.1	1977
400	128600	Aerial Crossing	Bexley Gully No.2	1977

Line	Meterage	Type	Location	Year Commissioned
400	128700	Aerial Crossing	Bexley No.3	1977
400	128900	Aerial Crossing	Bexley no.4	1977
400B	331666	Cased crossing	North Island Main Trunk	1981
400B	347555	Cased crossing	Auckland-Hamilton Motorway	1981
400B	379659	Cased crossing	Carbine Road	1981
400B	379993	Cased crossing	Auckland-Hamilton Motorway SH 1	1981
400B	380786	Cased crossing	Mount Wellington Highway	1981
402	5630	Cased crossing	North Island Main Trunk	1981
402	6018	Cased crossing	SH 1	1981
402	28650	Cased crossing	East Coast Main Trunk Railway	1981
402	32233	Cased crossing	SH 26	1981
402	34103	Cased crossing	Kuranui Road	1981
402	38217	Cased crossing	Scott Road	1981
402	39333	Cased crossing	Morrinsville-Walton Road	1981
402	39964	Cased crossing	East Coast Main Trunk Railway	1981
402	47492	Cased crossing	SH 27	1981
405	5739	Cased crossing	North Island Main Trunk	1984
405	6144	Cased crossing	Paerata Road (SH 22)	1984
405	8800	Cased crossing	Mission Bush Branch	1984
405	19729	Cased crossing	Mission Bush Branch	1984
407	211	Cased crossing	Kuranui Road	1982
412	5028	Cased crossing	SH 3	1983
412	8038	Cased crossing	North Island Main Trunk	1983
412	8343	Cased crossing	SH 30	1983
430	15	Cased crossing	North Island Main Trunk	1982
430	96	Cased crossing	Sylvia Park Road	1982
430	1036	Cased crossing	Great South Road	1982
430	1384	Cased crossing	North Auckland Railway	1982
430	1708	Cased crossing	Southdown Freight Terminal Railway	1982
430	5510	Cased crossing	Onehunga Port Railway	1982

Line	Meterage	Type	Location	Year Commissioned
430	6069	Cased crossing	Gloucester Park Road	1982
430	6316	Cased crossing	SH 20 Motorway	1982
430	19610	Cased crossing	West Coast Road	1982
430	19751	Cased crossing	North Auckland Line	1982
430	22268	Cased crossing	North Auckland Line	1982
430	31422	Cased crossing	North Auckland Line	1982
430	36994	Cased crossing	North Auckland Line	1982
430	45580	Cased crossing	North Auckland Line & SH 16	1982
430	71633	Cased crossing	North Auckland Line	1982
430	90123	Cased crossing	North Auckland Line	1982
430	99851	Cased crossing	SH 1	1982
430	158545	Cased crossing	SH 1	1982
430	172216	Cased crossing	North Auckland Line	1982
433	6532	Cased crossing	SH 1	1983
433	13256	Cased crossing	SH 12	1983
434	8712	Cased crossing	SH 1	1983
438	0	Cased crossing	Parrs Cross Road	1985
500	8414	Cased crossing	North Island Main Trunk	1982
500	12770	Cased crossing	SH 3	1982
500	80711	Cased crossing	Kinleith Branch Railway	1982
500	81644	Cased crossing	SH 1	1982
500	93773	Cased crossing	Rahui Road	1982
500	105761	Cased crossing	SH 30	1982
500	127438	Cased crossing	SH 5	1982
502	7676	Cased crossing	Murupara Branch Railway	1982
502	11045	Cased crossing	Galatea Road	1982
502	13636	Cased crossing	SH 30	1982
503	9915	Cased crossing	Tumunui Road	1983
505	2666	Cased crossing	Murupara Branch	1984
505	42842	Cased crossing	SH 2	1984
505	47775	Cased crossing	SH 2	1984
505	69499	Cased crossing	SH 2	1984

Line	Meterage	Type	Location	Year Commissioned
505	164543	Cased crossing	SH 2	1984
505	167149	Cased crossing	SH 2	1984
505	171986	Cased crossing	Whatatutu Road	1984
505	175294	Cased crossing	Cliff Road	1984
505	175979	Cased crossing	Matawai Road SH 2	1984
505	183931	Cased crossing	Matawai Road SH 2	1984
505	185557	Cased crossing	Shaw Orchard	1984
506	3756	Cased crossing	Waioeka Road SH 2	1984
507	4090	Cased crossing	Awakeri Road SH 2	1986
507	6246	Cased crossing	Railway Track & SH 30	1986
507	12877	Cased crossing	Kopeopeo Canal Outlet Pipe	1986
507	12932	Cased crossing	Patuwai Road	1986
508	1461	Cased crossing	SH 5	1987
601	13564	Cased crossing	Te Moana Road	1981
601	16224	Cased crossing	North Island Main Trunk	1981
601	16820	Cased crossing	SH 1	1981
602	680	Cased crossing	Pururi Street	1984
602	2042	Cased crossing	Castlecliff Industrial Line & Heads Road	1984
605	11151	Cased crossing	North Island Main Trunk & SH 1	1985
605	13790	Cased crossing	North Island Main Trunk	1985
605	14131	Cased crossing	SH 1 (Paraparaumu-Paekakariki)	1985
605	31313	Cased crossing	Paremata Haywards Road SH 58	1985
700	1900	Cased crossing	North Island Main Trunk, Railway Road	1982
700	75367	Cased crossing	SH 2	1982
700	84398	Cased crossing	SH 2	1982
700	151184	Cased crossing	Palmerston North-Gisborne Line & SH 2	1982
702	6137	Cased crossing	Napier Road SH 2	1983
702	6603	Cased crossing	Palmerston North-Gisborne Line	1983
702	7773	Cased crossing	Wairarapa Line	1983

Line	Meterage	Type	Location	Year Commissioned
702	9690	Cased crossing	Masterton Road SH 2	1983
702	14920	Cased crossing	Wairarapa Line	1983
703	226	Cased crossing	SH 2	1983
800	4263	Cased crossing	SH 1	1980
800	12880	Cased crossing	SH 5	1980
800	37750	Cased crossing	SH 29	1980
800	40165	Cased crossing	SH 29	1980
800	42390	Cased crossing	SH 29	1980
800	55098	Cased crossing	SH 29	1980
800	80560	Cased crossing	SH 2	1980
800	81500	Cased crossing	East Coast Main Trunk Railway	1980
803	1753	Cased crossing	SH 29	1982
805	7915	Cased crossing	East Coast Main Trunk Railway & SH 2	1980

D.4. COMPRESSORS

Station / Unit	Prime Mover	Rating Power of Prime Mover (kW)	Compressor model	Capacity (scmh)	Install Date
Henderson 1	Electric Drive	700	Ariel JGT/2	3,520	2017
Henderson 2	Electric Drive	700	Ariel JGT/2	3,520	2017
Rotowaro 3	Waukesha P9390 GSI Reciprocating	1,200	Worthington OF6XH4	61,300	1985
Rotowaro 4	Waukesha P9390 GSI Reciprocating	1,200	Worthington OF6XH4	61,300	1985
Rotowaro 5	Siemens SGT-1002S Gas Turbine	4,700	Delaval Stork 06MV4A Centrifugal	150,000	1998
Rotowaro 6	Siemens SGT-1002S Gas Turbine	4,700	Delaval Stork 06MV4A Centrifugal	150,000	1998
Pokuru 1	Waukesha L7042GSIU Reciprocating	746	Ariel JGR-4	29,900	1983
Pokuru 2	Waukesha L7042GSIU Reciprocating	746	Ariel JGR-4	29,900	1983
Kawerau 1	Waukesha F1197G Reciprocating	139	Ariel JG2	6,170	1985
Kawerau 2	Waukesha F1197G Reciprocating	139	Ariel JG2	6,170	1985
Mahoenui 1	Waukesha L7042GU Reciprocating	746	Worthington OF6SU-2	24,700	1979
Mahoenui 2	Waukesha L7042GU Reciprocating	746	Worthington OF6SU-2	24,700	1979
Mahoenui 3	Waukesha L7042GU Reciprocating	746	Worthington OF6SU-2	24,700	1979
Kapuni 2	Waukesha P9390GSIU Reciprocating	1,250	Worthington OF6H4	61,300	1969
Kapuni 3	Waukesha P9390GSIU Reciprocating	1,250	Worthington OF6H4	61,300	1969
Kapuni 5	MEP 8 Reciprocating	1,340	Ingersoll-Rand 4RD S	37,800	1969
Kaitoke 1	Waukesha L7042GU Reciprocating	746	Ingersoll-Rand IR2D	21,400	1984
Kaitoke 2	Waukesha P9390GSIU Reciprocating	1,250	Worthington OF6H4	54,000	1984
Mokau 1	Centaur 40	3,500	C304	270,000	2010
Mokau 2	Centaur 40	3,350	C304	270,000	2007

Appendix E System Schematic Diagrams

This section contains seven schematic diagrams of the Firstgas pipeline systems:

- North System
- Kapuni to Rotowaro and Morrinsville
- South System 1
- South System 2
- Frankley Road System
- Bay of Plenty System
- Maui System

These diagrams show the relative locations of all station including their type, name, and reference number. They also show pipeline segments and include nominal bore, the distance between station and the lengths of the various pipelines can be calculated by subtracting reference numbers, the last digit being tenths of a kilometre.

Figure 34: North System

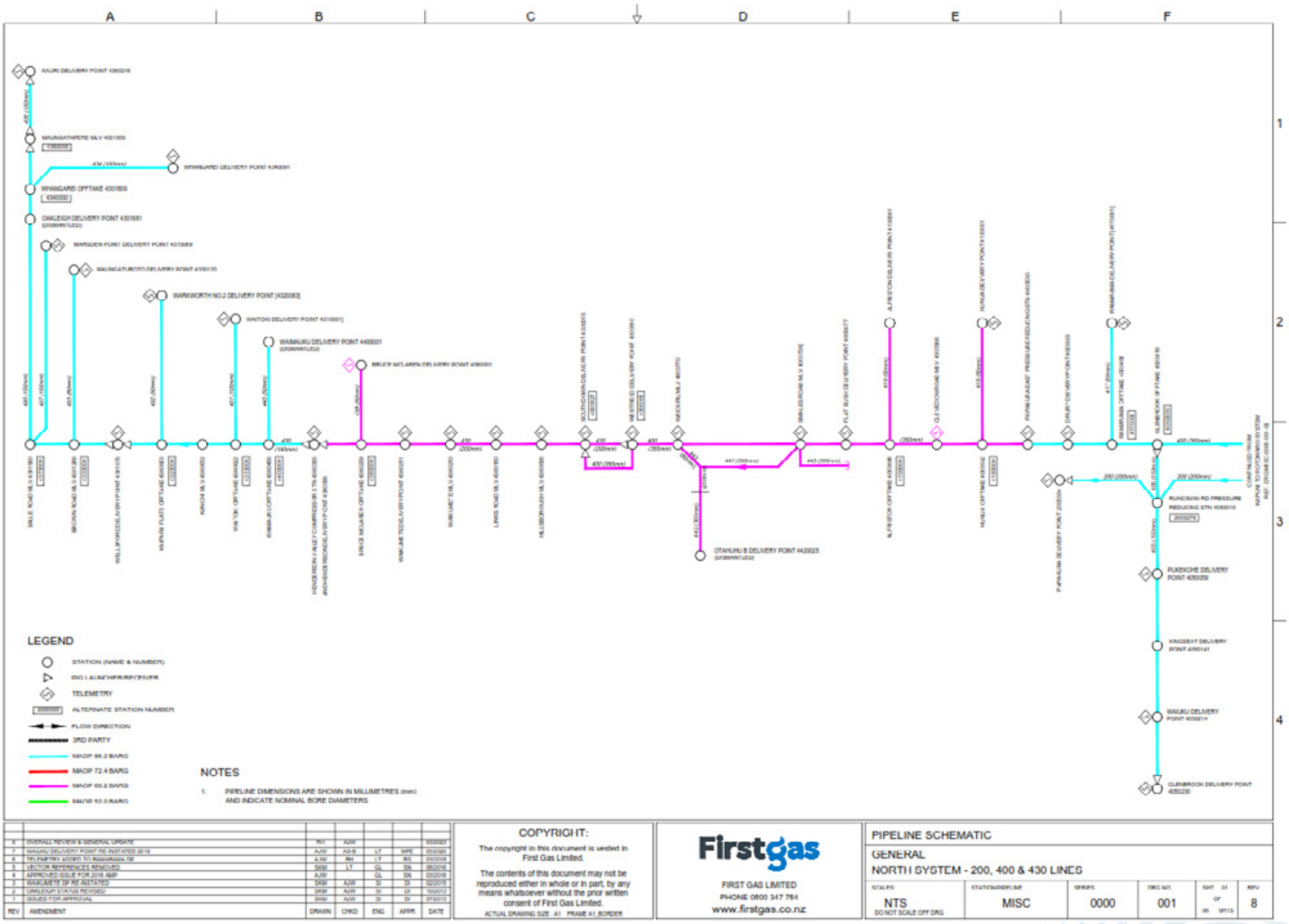


Figure 35: Kapuni, Rotowaro and Morrinsville System

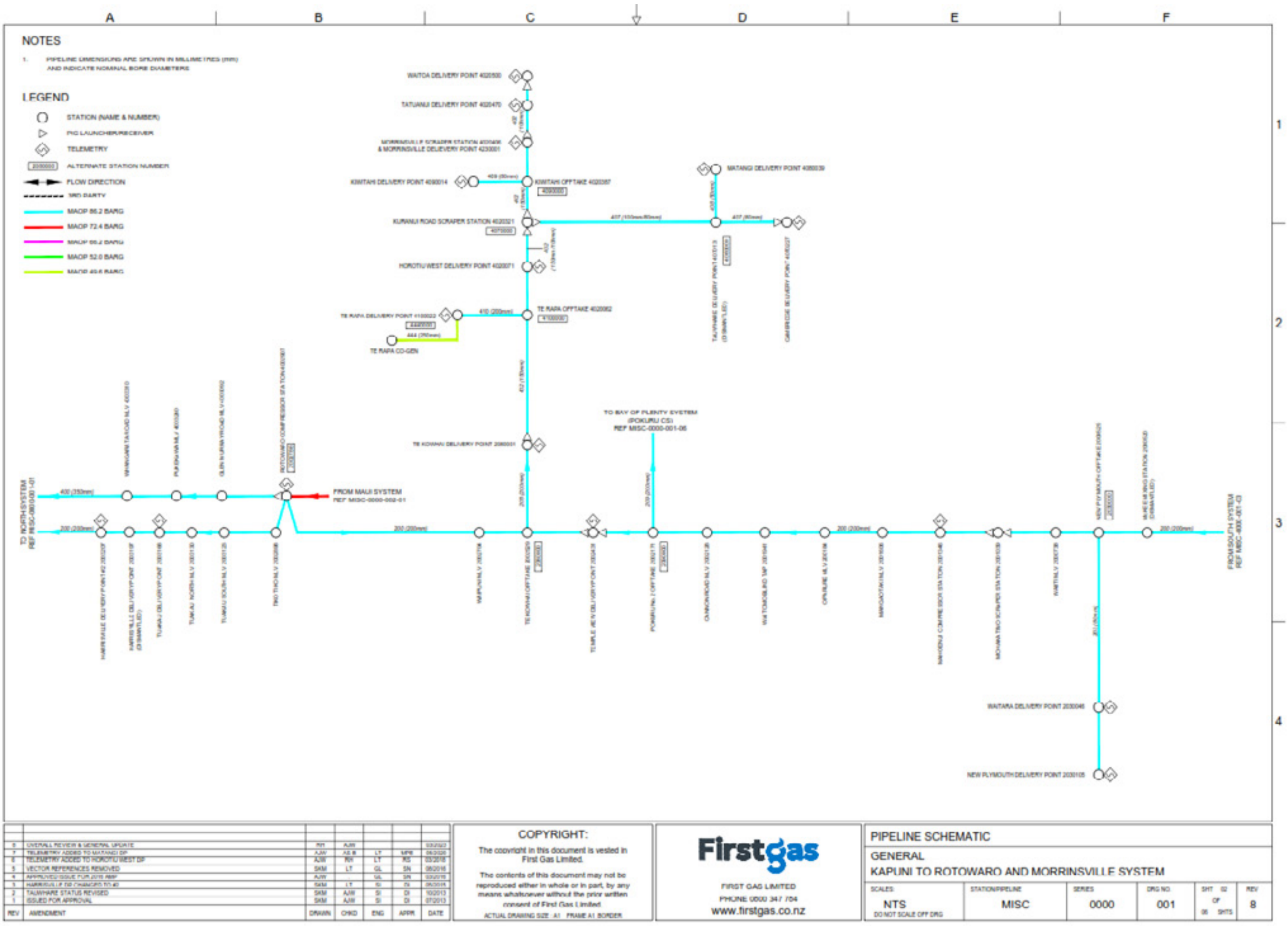


Figure 36: South System 1

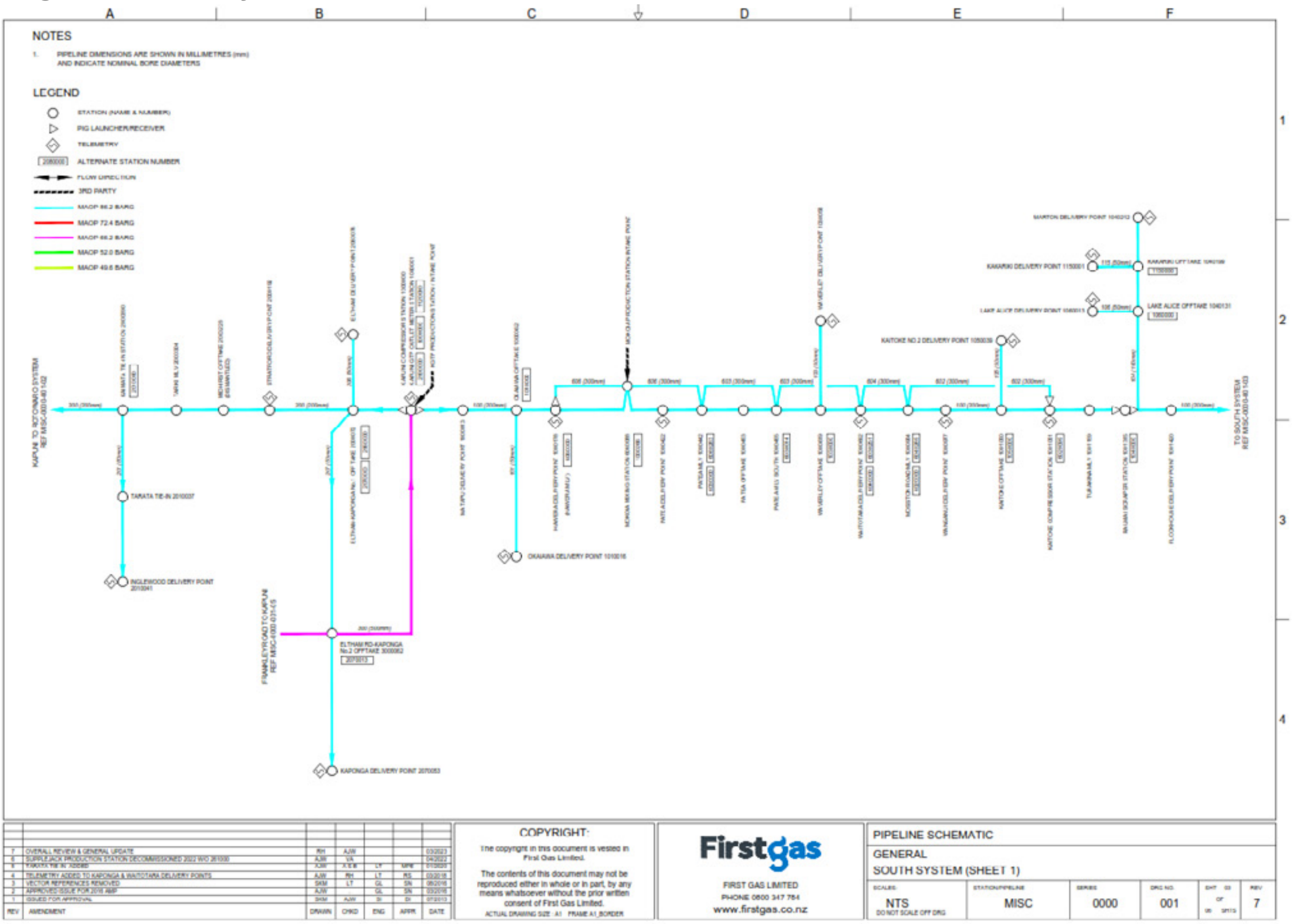


Figure 37: South System 2

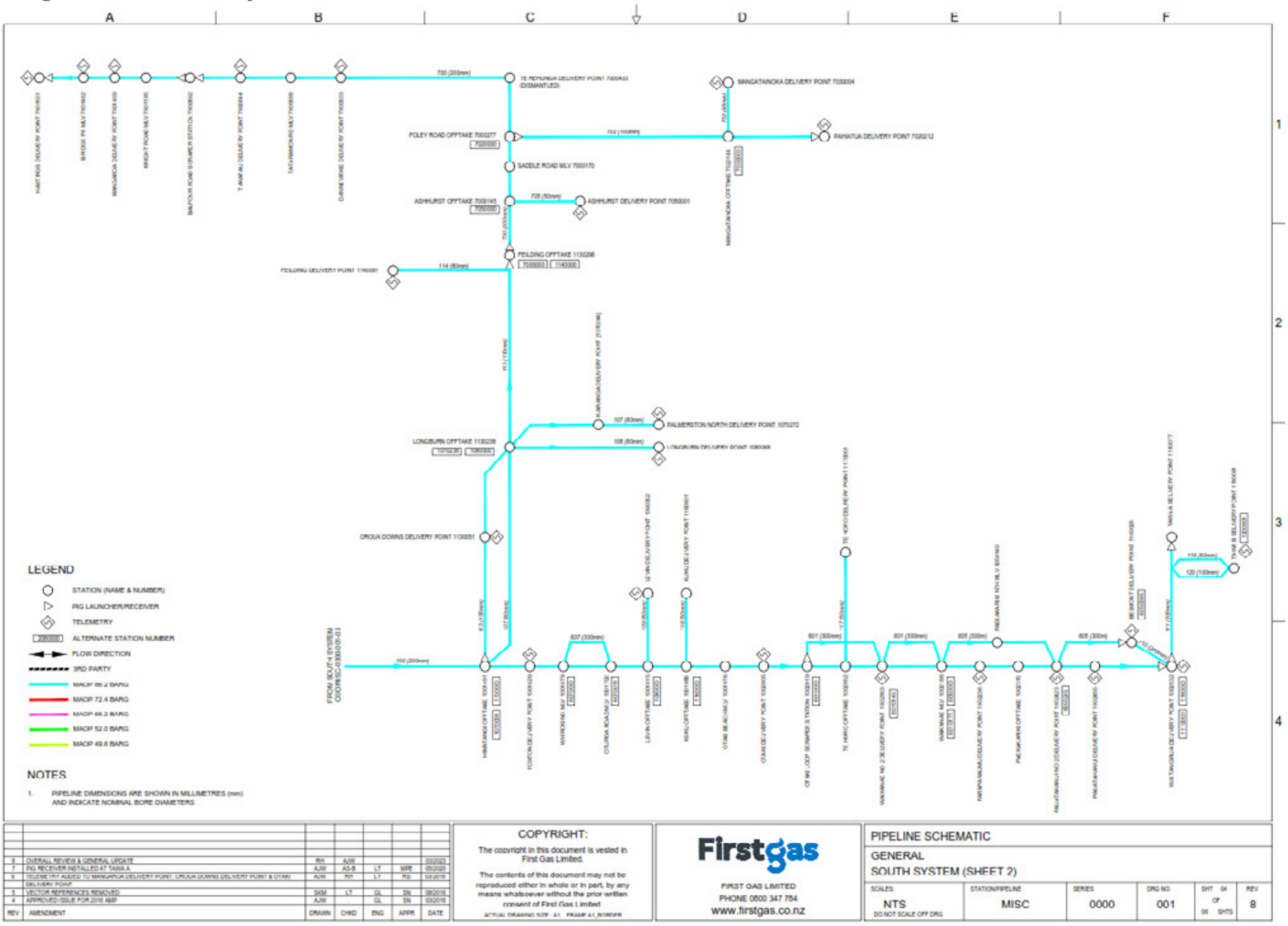


Figure 38: Frankley Road System

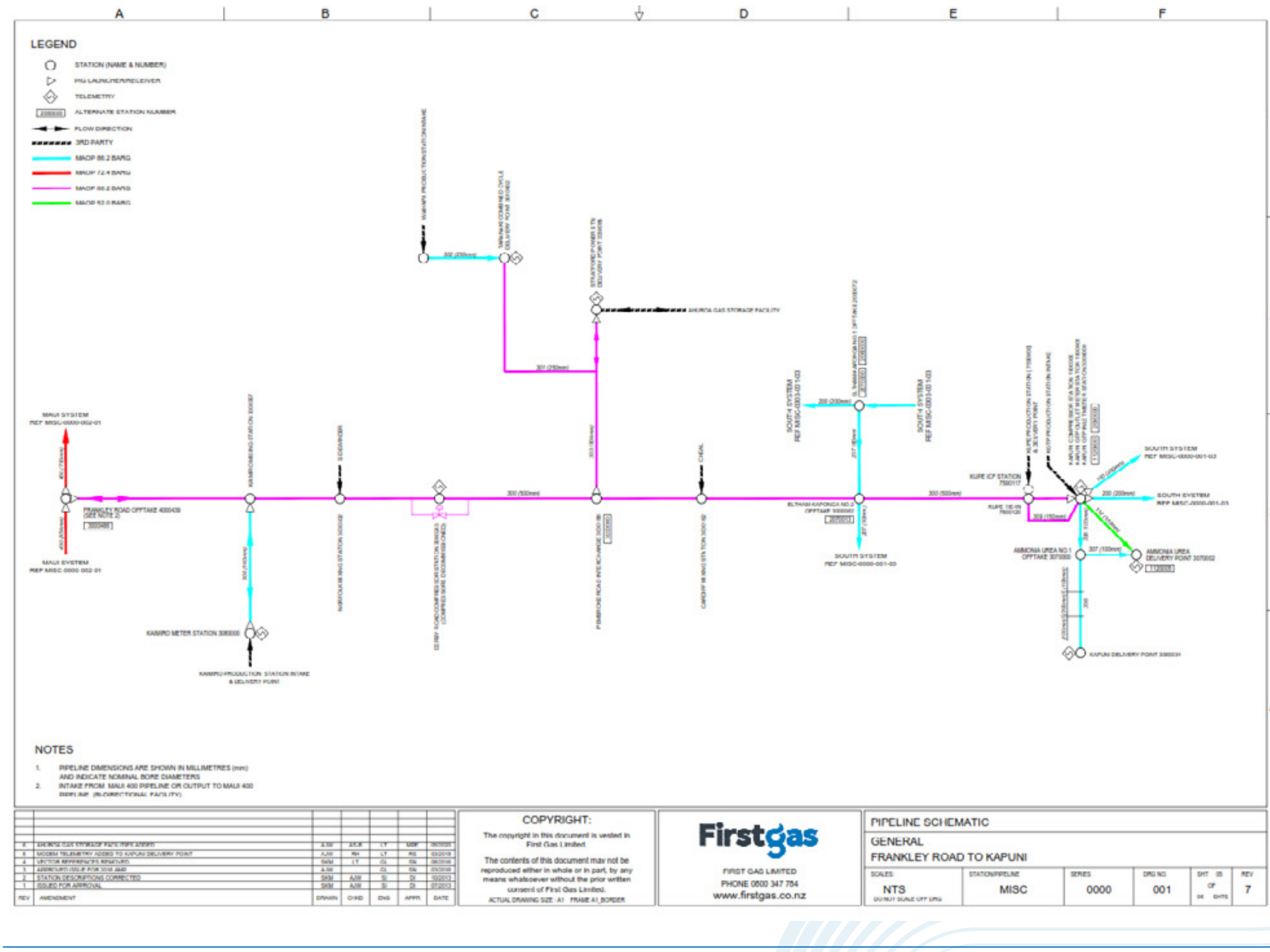


Figure 39: Bay of Plenty System

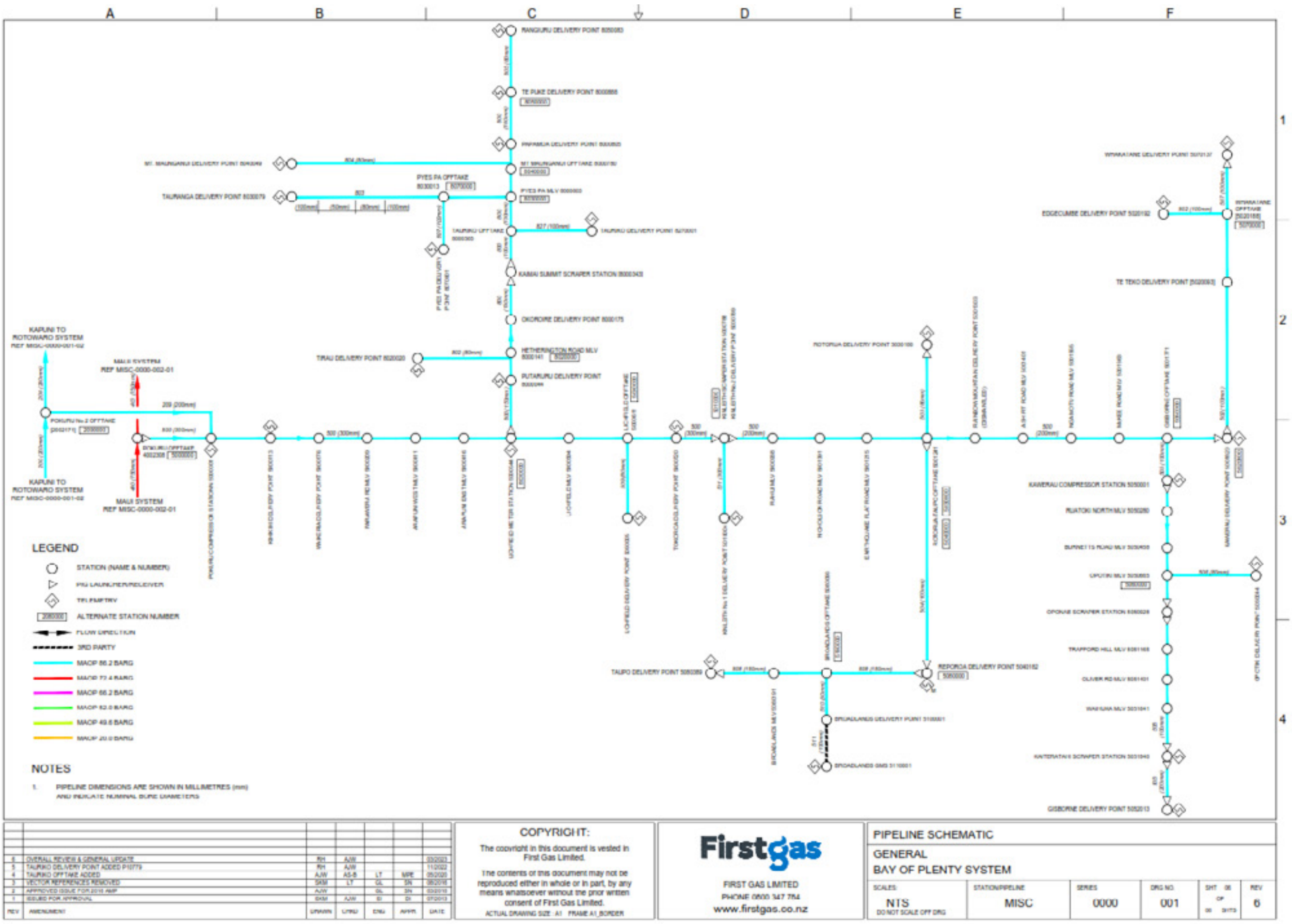
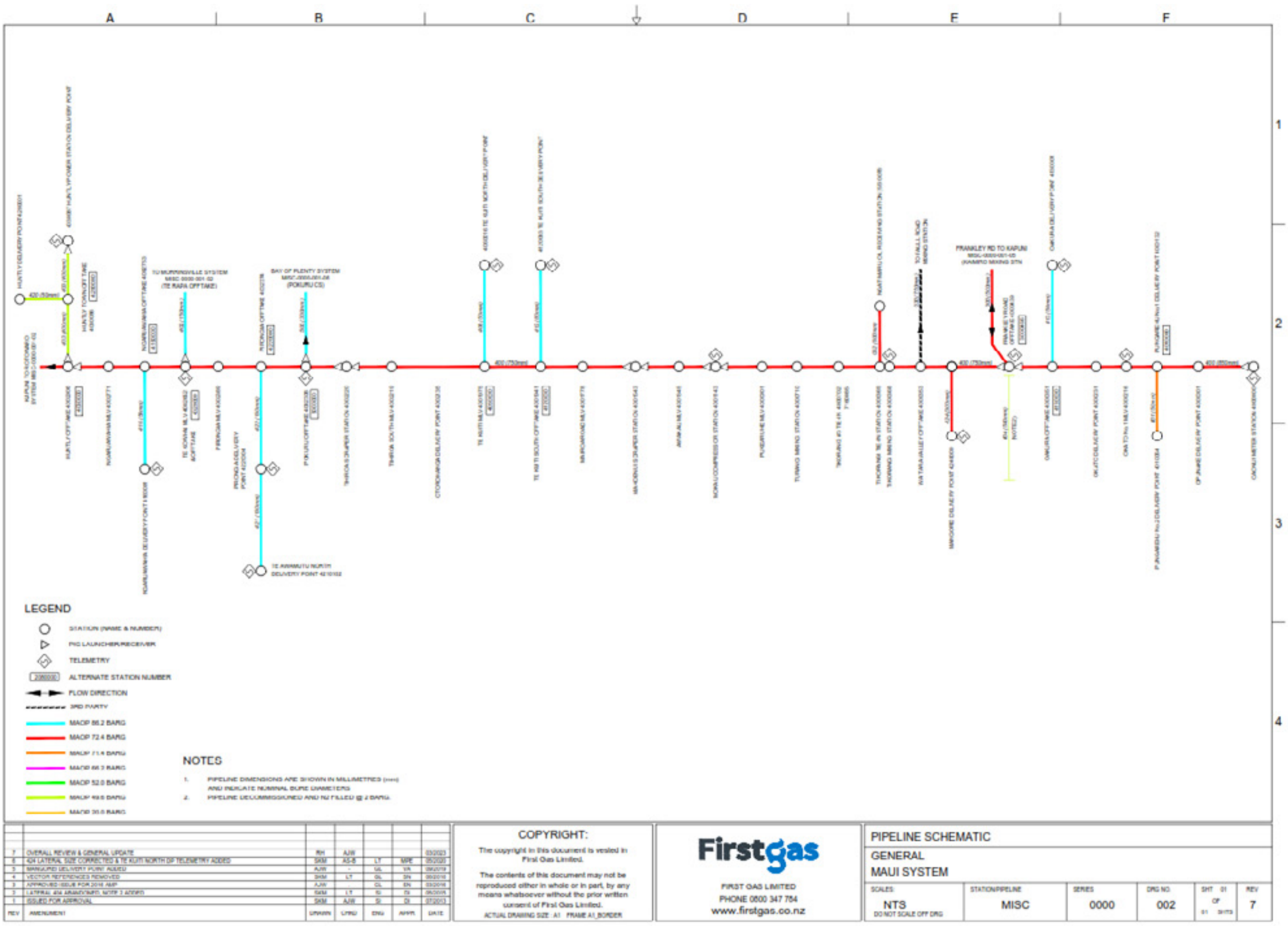


Figure 40: Maui System



The term system development is used to describe capital investments that increase the capacity, functionality, or extent of the transmission system. In line with Information Disclosure requirements, these investments are categorised as:

- **Consumer connections**: expenditure to connect a new consumer to the transmission system (at a new or upgraded delivery point) or a new gas producer (at a new or upgraded receipt point).
- **System Growth:** expenditure to ensure demand can be met on the transmission system, including in the event of any material change in the location or extent of injection of gas into the transmission system and/or maintain current supply security levels.

F.1. Consumer Connections

Gas demand can be broken into 3 main sectors:

- Petrochemical production - where gas is used as a feedstock as well as fuel.
- Power Generation - where gas is used as fuel, in base load and/or peaking plant.
- Direct Use - where gas is used to meet process heat requirements or for other industrial applications.

New Zealand must find ways to decarbonise whilst retaining industry. However there is currently significant uncertainty with new gas consumer connections.

At this stage, no provision is made in the 10-year capex forecasts for any specific project expenditure but a general allowance had been made in this category should an opportunity arise that requires SEED funding to develop the scope, and or minor works.

Firstgas forecasts anticipated expenditure throughout the planning period. Growth in any of the above sectors is subject to a range of influences, including:

- the general economic outlook
- Policy and legislative changes that may impact on consumer connections
- consumer-specific factors, such as the consumer's alternative investment opportunities and the state of the particular market in which the consumer operates
- the attractiveness of alternative energy sources (increasingly, renewables)
- land and consenting issues, and
- the availability and price of gas,

These factors often impact on the timing of the forecast expenditure and result in that expenditure being variable, rather than more evenly distributed. Forecast opportunities may also fail to materialise while other, unforeseen prospects are prioritised. Firstgas aims to meet consumers' need by ensuring the transmission system can accommodate their loads in the required timeframe.

Forecast expenditure is summarised in *Appendix J – Expenditure Overview*.

System Growth

Investments in this area include enhancements to the capacity and/or configuration of the transmission system that:

- Address any potential system security breaches
- Extend the transmission system into new or developing areas, and
- Cater for organic load growth or changing consumer demand in existing areas.

Planning Principles

The gas transmission system is regulated under the Health and Safety in Employment (Pipelines) Regulations (1999) and requires that the pipelines be issued with a certificate of fitness by an independent certifying authority. In order to meet the requirements for certificate of fitness, the transmission system is designed, operated and maintained in accordance with the Australian Standard AS 2885 suite of Standards for High Pressure Pipelines.

In order to meet these statutory requirements, as well as commercial imperatives, the planning principles for the transmission system seek to ensure that:

- All transmission system assets will be operated within their design rating
- The design and operation of the system will not present a safety risk to staff, contractors or the public
- The system is designed to meet the Transmission System Security Standard, which includes requirements set out in the Critical Contingency Management Regulations
- Reasonable gas supply (hence transmission capacity) requirements for Customers will be met
- The transmission system is designed to include a prudent capacity margin to cater for foreseeable short to medium-term load growth
- Equipment is purchased and installed in accordance with good high pressure gas pipeline standards to ensure optimal asset life and performance, and
- Gas transmission system investment will provide an appropriate commercial return for the business.

Investment Drivers

Firstgas, as a requiring authority, receives early notification of resource consent applications. The earlier the planning commences, allows more scope for optimal design and procurement, and maximise synergies within Firstgas.

For new prospective loads, growth investments are undertaken on the back of firm commitments from the consumer to pay for the capacity created or where the respected revenue will cover the costs of the investment and not adversely affect existing users of the transmission system. This complies with the Commerce Commission’s pricing principles, i.e. a “user-pays” approach as far as practicable, which minimises the likelihood of consumers contributing to the costs of investments they do not use. Regular re-forecasting allows the timing of large projects to be re-evaluated and forecasts to be adjusted accordingly.

In high growth areas, system enhancements may be brought forward to ensure a larger system capacity buffer. This allows for unexpected load increases or unexpected delays in the delivery of solutions.

The primary planning objectives are to identify and prevent foreseeable transmission system related capacity constraints, in a safe, technically prudent and cost-effective manner. The planning process involves identifying and resolving:

- Potential breaches of the Transmission System Security Standard (see *Appendix G*)
- Supply to new developments or areas requiring gas connections
- Supply to existing connections requiring increased capacity
- Supporting Transition to New Zero - adaption networks to allow injection of Biomethane or Hydrogen.

These situations are identified through system measurement, monitoring (system pressure and flows), and gas flow modelling of future load growth scenarios.

F.2 Development Planning

Planning for system growth investments requires that consumer's needs are anticipated so that, by timely investment in additional capacity, potential shortfalls of capacity are avoided, or breaches of the security criteria.

These developments need to fit within the context of the wider asset management activities (e.g. renewal plans), such that investments are optimised across all business objectives and constraints. As described in *Appendix H – Asset Management Approach*, assets are managed using an asset lifecycle approach that takes different equipment design requirements into account.

The development process involves modelling, planning and designing the gas transmission system, capital budgeting, prioritising the investment programme, and implementing the chosen solutions.

Needs Identification

If a shortage of uncommitted operational capacity is identified at a delivery point consideration will be given to investing to increase capacity. This will take consideration for potential options and risks, including the security impacts elsewhere in the transmission system if the load continued to grow at that delivery point.

Options Analysis

When the need for a pipeline and/or station upgrade is indicated, investment objectives are identified and options to achieve those objectives are evaluated. Options are considered from a consumer perspective, for their financial impacts, and for risk. The risk evaluation will include the consequences of doing nothing, or of using commercial mechanisms to manage demand growth. The options considered are summarised in the business case for the investment.

Solutions

In evaluating possible solutions, the following factors are amongst those considered to ensure an optimal investment decision:

- Opportunities for load diversity (mixing commercial and residential loads can provide diversity)
- Transfer of load between a heavily laden and a less loaded gate station
- Potential for a change in delivery pressure to alleviate the limitation, and
- Potential synergies with third party projects - e.g. asset relocation relating to road realignment or new road construction activities.

Solutions addressing system capacity and security constraints may be asset or non-asset based, and the optimal solution may not necessarily result in system enhancement. In evaluating the solution options, the following will be considered:

- Risk, to test that the solution cost is not disproportionate to the benefits obtained
- Long-term impacts of solutions to short-term issues to avoid asset overbuild or stranding
- System development programme alignment with other work programmes such as asset maintenance, and
- Commercial viability of the recommended solution.

Significant efficiencies can result from solutions that allow investment to be deferred, to align with other activities, without compromising capacity or supply pressure. Where investment is required, lower-cost options are prioritised to reduce the cost to consumers.

Station Capacity Upgrades

To meet System Security Standard requirements, a station should be able to meet the peak hourly flow predicted. At delivery points, the maximum design capacity of individual components (e.g. the filter, heater, regulators, meter and pipework) is checked using manufacturers' data at design operating conditions. This information is retained in a controlled database.

The component(s) that limit a station's ability to meet design flow are identified and options considered to alleviate that limitation or to manage the peak flow another way.

Any station upgrade solution will be designed to meet the capacity requirement forecast for the planning period and wherever practicable will be implemented before the flow limitation becomes an issue.

Project upgrade costs for projects in the next financial year are based on FEED (Front End Engineering Design) studies undertaken for the project. This provides a defined scope of work for the activities, with an estimated cost and accuracy.

For projects arising within the current year, project will be prioritised based on risk and consumer demand. In general growth projects will be prioritised. If required, contract resources will be utilised to ensure projects are completed.

Pipeline System Upgrades

Discrete transmission pipeline systems are analysed individually using demand growth data and normal system operating conditions. Each system must be designed and operated to meet the system security standard requirements (defined in GTS-01).

Where pipeline uncommitted operational capacity is forecast to be at or approaching zero, system reinforcement options or other capacity management options will be identified. System reinforcement solutions may include pipeline options and/or compressor options.

The system reinforcement solution will meet the design capacity for the planning period. Pipeline upgrade solutions will be considered if there is a suitable business case.

As with Station Upgrades forecast for the next financial year, costs are based on FEED studies.

Appendix G Security Standard

The purpose of the ***Gas Transmission System Security Standard 09334*** is to define the minimum level of system security and transmission system performance to be applied in the operation and development of the system, under all reasonably anticipated operating conditions.

The primary trigger point for a transmission system reinforcement investment is when the forecasted peak gas demand profile under reasonably anticipated operating conditions creates a situation where one or more of the system requirements defined in the standard can no longer be met.

The standard provides:

- A clear measure for acceptable transmission system output performance, allowing easy identification of inadequate system operation or areas requiring attention.
- A clear design standard that identifies when investments may be required to augment the transmission system capacity to deal with increased gas demand.
- A clear means of communicating to internal and external stakeholders the level of service they can reasonably expect from the gas transmission system.
- High-level design requirements to ensure that gas injected into the transmission system can be conveyed to consumers taking gas from the system at appropriate capacity and reliability levels, under all reasonably anticipated operating conditions.

The standard does not refer to the technical and safety aspects of transmission system asset performance.

Purpose of the Standard

The purpose of this standard is to define the minimum level of system security and transmission system performance to be applied in the operation and development of the Firstgas transmission system, under all reasonably anticipated operating conditions.

Scope

This standard applies to the First Gas transmission system, which is comprised of various interconnected high-pressure gas pipelines with normal operating pressures higher than 20 barg. This system conveys gas from several receipt points to numerous delivery points throughout the North Island. Receipt points are located at or near gas production plants, with the demarcation point between the First Gas transmission system and producer plants generally at the first valve downstream from the metering point.[1] Delivery points are where consumers (including gas distribution network owners) receive supply from the transmission system, and the demarcation point is at the first valve downstream from the (First Gas-owned) metering system.

Some dedicated consumer supplies may be designed to different security levels, as contractually agreed to with consumers. These are excluded from this standard.

Purpose

The System Security Standard fulfils a threefold function providing:

- A clear measure for the minimum acceptable transmission system output performance, allowing easy identification of areas where attention may be required.
- A clear design standard that identifies when investments may be required to augment the transmission system capacity.
- A clear means of communicating to internal and external stakeholders the level of service they can reasonably expect from the Firstgas transmission system.

The System Security Standard sets the high-level design requirements for the transmission system to ensure that gas fed into the system can be conveyed to consumers taking gas from the system at appropriate capacity and reliability levels, under all reasonably anticipated operating conditions. The primary trigger point for a transmission system reinforcement investment is when the forecast peak gas demand profile under such operating conditions would create a situation where one or more of the system requirements discussed in Section 3 can no longer be met.[2]

The Standard does not refer to the technical and safety aspects of transmission asset performance.[3]

1 At some receipt points, First Gas owns the metering system that monitors and quantifies the flow of gas into the Transmission System.

2 Alternatively, Firstgas may decide to avoid a forecast breach of the System Security Standard by limiting the allocation of new gas capacity to shippers, until an acceptable commercial and/or regulatory arrangement is reached that would allow Firstgas to recover the cost of reinforcing the transmission system at an appropriate rate of return.

3 The Firstgas transmission system is regulated under the Health and Safety (Pipelines) Regulations (1999), which requires that the pipelines must be issued with a Certificate of Fitness by an independent Certifying Authority. In order to meet the requirements for Certificate of Fitness, Firstgas designs, operates and maintains the transmission system in accordance with the Australian and New Zealand standard (AS/NZS) 2885 suite of Standards for High Pressure Pipelines.

Definitions

The following terms are defined for the purpose of this standard:

A ***Critical Contingency*** is defined in terms of The Gas Governance (Critical Contingency Management) Regulations 2008 (the Regulations). A Critical Contingency is declared when, based on observed operating and gas consumption conditions, there is a reasonable likelihood or an actual breach of a specified threshold at one or more of the points on the transmission system defined by the regulations. Specified thresholds are defined as a minimum operating pressure and a time before the minimum operating pressure is reached.

The ***Critical Contingency Operator (CCO)*** is a role established the Regulations. One of the obligations of the CCO is to declare a Critical Contingency when there is a likelihood or actual breach of the thresholds set in the Firstgas ***Critical Contingency Management Plan (CCMP08867)***. The Firstgas CCMP is compiled and maintained in accordance with requirements set out in the Regulations. The CCMP includes important information such as all necessary communications to industry and the sequence of demand curtailment and restoration during a Critical Contingency Event.

The ***Critical Contingency Operator Communications Plan*** (document CCO-003) is prepared in accordance with the Regulations and describes the communications between the CCO and Firstgas during a Critical Contingency.

The ***design capacity*** of an asset is the maximum rated output the asset is capable of delivering over an extended period without excessive loss of life of the asset, considering the peak profile of gas demand and the operating environment of the asset.

A ***pipeline system*** refers to a part of the overall Firstgas transmission system, where one or more pipelines can be logically grouped together as a geographically contiguous unit.

Reasonably anticipated operating conditions refer to conditions where:

- A pipeline system is operating in its normal design configuration, with all assets fully functional (including where redundant assets are operating following any failure for which they are the back-up).[4]
- The gas demand on the pipeline system does not exceed that which could be reasonably forecast to occur under normal demand conditions (i.e. temperature conditions not being more extreme than a 1-in-20 winter), where such forecast is based on the volume of gas that is contracted to be delivered through the system and applying the Firstgas gas demand forecasting methodology.[5]
- Gas supply levels are sufficient to meet the gas demand on the pipeline system.
- No Critical Contingency has been declared, nor any Critical Contingency thresholds are approaching breach.

Security Standards

The Firstgas transmission system and all its pipeline systems shall be designed, constructed and operated to ensure that the following conditions are met under reasonably anticipated operating conditions.

4 Asset redundancy is covered in Section 1.8 of this System Security Standard
5 Firstgas demand forecasting methodology is described in the Firstgas Transmission Asset Management Plan

PHYSICAL SYSTEM CAPACITY

The design capacity of any component of the gas transmission system shall not be exceeded. Specifically:

- For gas pipelines – 100% of the maximum allowable operating pressure level (MAOP) shall not be exceeded under stable operating conditions, or 110% of MAOP under transient operating conditions (as defined in *AS2885/1*, 2012).
- Rotating equipment - the maximum design gas flow rate or pressure levels (inlet and output) shall not be exceeded.
- Delivery point components (including heaters, valves, metering systems, regulators, etc.) – under stable operating conditions the design capacity of any component shall not be exceeded.

MINIMUM TRANSMISSION SYSTEM PRESSURE

The minimum operating gas pressure on any part of the transmission system shall not fall below the greater of the following levels:

- The minimum operating pressure defined under the CCMP requirements set out in the Regulations R25(1)(a) for that specified point[6]. or
- The minimum contractually agreed pressure that Firstgas must deliver at a specific customer inlet point.

Critical contingency threshold values are defined as minimum operating pressures and time before these minimum operating pressures are reached and are listed in table 1 below[7]. The CCO must declare a Critical Contingency when one of the pressure thresholds is breached or if the CCO has a reasonable expectation that a breach of a threshold is otherwise unavoidable.

Critical Contingency Threshold

Delivery Point	Minimum Operating Pressure (at inlet)	Time before Minimum Operating Pressure is reached
Cambridge DP	30 barg	5 hours
Gisborne DP	30 barg	5 hours
Hastings DP	30 barg	5 hours
KGTP	35 barg	3 hours
Tauranga DP	30 barg	6 hours
Taupo DP	30 barg	5 hours
Waitangirua DP	37 barg	10 hours
Westfield DP	37.5 barg	6 hours
Whakatane DP	30 barg	5 hours
Whangarei DP	27.5 barg	5 hours

6 R25(1)(a) specifies the permissible limits for thresholds to be specified in the Critical Contingency Management Plan. This is specified as a range. Firstgas Group as the Transmission System Owner has defined, in consultation with the gas industry, a series of fixed pressure values and times that fall within these ranges that would give rise to a *Critical Contingency* being declared.

7 With the exception of Bertrand Road pressure on the Maui pipeline (known as Target Taranaki Pressure), over-pressure situations at delivery points are not considered a design standard, as these are unlikely to arise and, in addition, protection against over-pressure is provided at all delivery points.

Delivery Point	Minimum Operating Pressure (at inlet)	Time before Minimum Operating Pressure is reached
Rotowaro DP	30 barg	3 hours

Firstgas Transmission sets a 30 barg minimum pressure at the inlet of all other delivery points.

Exceptions

- Transmission Pipelines and their associated delivery points which are permanently operated at distribution pressures (pressures less than 20 barg).[8]

COMPONENT REDUNDANCY LEVELS

The following minimum redundancy levels are required for the various components making up the gas transmission system[9]:

Asset Type	Redundancy Level
Pipelines	N
Rotating Equipment[10]	N-1
Pressure regulation streams at delivery points (peak gas delivery >= 20GJ per day)	N-1
Other delivery point equipment (including pressure regulation streams at delivery points with peak gas delivery < 20GJ per day)	N

Exceptions

- N+1 redundancy for rotating equipment at customer connections is not required, unless specifically contracted for.
- N+1 redundancy for rotating equipment is not required at low-demand compressor stations. On the Firstgas Transmission network, this includes Kawerau Compressor Station.
- The Pokuru compressor station does not meet N+1 redundancy for demands on the Bay of Plenty Gas Transmission system. However, this station is supported directly by Mahoenui compressors from the 200 line, therefore, Pokuru compressor station is considered to meet the N+1 redundancy standard.

8 To allow for Transmission pipelines from Waitangirua to Tawa A and B and the pipeline from Te Puke to Rangiuru, both of which are operated at less than 20bar continuously.

9 An N redundancy level means that no redundancy is built into the system and that a single component outage can compromise the ability of a *pipeline system* to deliver its required output. An N+1 redundancy level means that a failure on any single component will not affect the ability of the system to deliver its required output.

10 The transmission system must have sufficient capacity to allow for a maximum of 1 hour delay (or 3 hours if located in a remote rural location) between the outage of a primary gas compressor unit and achieving full operational status of the stand-by unit, without breaching minimum pressure criteria.

ASSET MANAGEMENT

This section describes Firstgas Group Limited's (Firstgas) approach to asset management and how this supports meeting the Company's performance objectives and the expectations of stakeholders. It is structured as follows:

- **Asset Management Improvements:** The adoption of *ISO55001:2014* as a means to ensure best practice in delivering asset management activities.
- **Asset Management Framework:** describes the approach to ensuring alignment between corporate objectives and day-to-day asset management activities.
- **Asset Management System:** describes the components of the asset management system and provides an overview of the key elements.
- **Business Support:** The role of managing assets with people with the right competencies to achieve asset management objectives over the planning period
- **Performance Measures:** sets out the overall asset management performance objectives.
- **Asset Management Maturity Assessment Tool (AMMAT):** describes the outcome of the AMMAT review and other benchmarking exercises.

ASSET MANAGEMENT IMPROVEMENTS

Firstgas has engaged with external consultants (Assetivity[1]) to provide independent advice on the maturity of Asset Management with 2 key objectives to:

- Identify any gaps between current state and the state required to achieve alignment to *ISO55001:2014* and
- From the findings, develop recommendations and a roadmap that would establish a clear path to improvement against *ISO55001:2014* for Firstgas Group's regulated businesses.

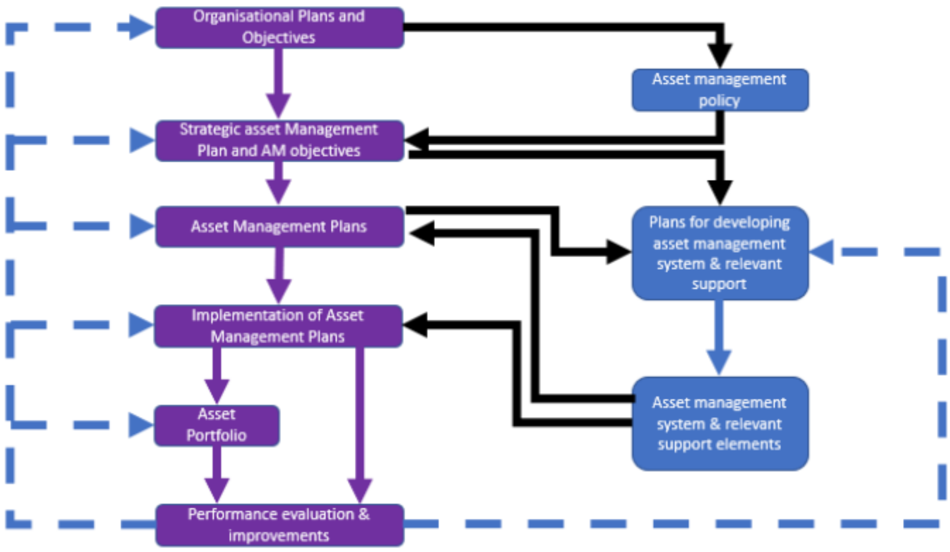
The outcome of the assessment has determined that Firstgas fully complies with 14 of the 27 clauses within *ISO55001:2014* and in the process of improving processes and procedures with the remaining 13 clauses. These have been shaped into a roadmap for achieving full compliance which comprises of the following steps:

- Improve Internal Stakeholder Communication
- Review Asset Management System Performance
- Review Asset Management Information Capture and Management
- Ensure Contractor Management is Holistic
- Ensure Competence Management accounts for Asset Management Competence
- Review Stores and Inventory Management Processes and Impact on Asset Management System Risk.

Consider a Combined Business Strategic Asset Management Plan

[1] Assetivity is a member of the Endorsed Assessor Scheme (EAS) with the Institute of Asset Management (IAM), Assetivity is authorised to conduct assessments and issue certificates of compliance with the requirements of *ISO55001*: 2014

Figure 42: Overview of asset management framework



Asset Management System

The Asset Management System is an important function of this system linking corporate objectives and stakeholder requirements to specific asset management approaches through the Asset Management Policy.

The asset management system aligns with the requirements specified by *ISO55001* and seeks to reflect good practice. This system includes the following components:

- **Asset Management Policy, Strategy and Objectives**: aligns the asset management approach with corporate objectives. The asset management objectives reflect this policy by emphasising the need for safety, stakeholder needs and the importance of effective risk management.
- **Asset Management Plans**: reflects the asset lifecycle model and aligns regular processes and activities with high-level objectives.
- **Asset Management Enablers and Controls:** influence and apply to all the other elements of the asset management system.
- **Risk and Review:** explains the approach to managing risk on the network, including how risk is identified and classified, and how appropriate actions are taken to manage the risks identified.
- **Life Cycle Delivery:** provides an overview of the approach to managing the gas transmission assets.

H.3.1 Asset Management Policy, Strategy & Objectives

Asset Management Policy

The Asset Management Policy provides a high-level statement of the asset management direction, principles and guiding objectives. The policy provides direction for asset management decisions and how the assets are managed.

The purpose of the policy is to reflect corporate objectives and stakeholder needs in terms that can be translated into the asset management documentation.

The policy also sets out key asset management principles that flow through Firstgas processes and systems. This is important to ensure the necessary relationships between objectives and what the asset management practices aim to achieve.

The policy is set out below and has been approved by the Firstgas Board.

Firstgas

ASSET MANAGEMENT POLICY

Firstgas's asset management policy is to effectively manage the Firstgas Group assets across their entire lifecycle in a safe, efficient and environmentally appropriate way to serve the needs of our customers, stakeholders and end-users while optimising the long-term return of our shareholders.

Achieving Operational Excellence in Asset Management is key to delivering on First Gas's Mission:

Safely and reliably delivering energy that is affordable and acceptable to New Zealand families and businesses.

To deliver on our asset management policy First Gas will:

- Prioritise the integrity of our assets to ensure the safety of the people and places affected by our operations.
- Provide a reliable, resilient and secure service that meets customer needs.
- Preserve the environment by operating in a manner that mitigates environmental risks.
- Address and meet all legislative requirements.
- Communicate our investment plans to stakeholders, particularly the communities that host our assets.
- Operate in a manner that optimises the long-term financial outcomes for our shareholders.
- Balance the needs of competing objectives in a consistent and transparent manner.

To achieve and monitor this we will:

- Engage with our stakeholders in an open and transparent manner, integrating customers into our decision making.
- Provide efficient and effective systems for whole of life asset management processes.
- Regularly review our performance using relevant leading and lagging indicators.
- Grow the organisational competence and capability of Firstgas in step with our asset management objectives.
- Ensure our Board and management are fully informed with accurate and timely data to support their responsibilities.
- Communicate with all our people and key stakeholders on all aspects of this policy.
- Continuously strive for improvement in all areas of asset management and work to align with ISO 55000.

All our people are responsible for:

- Ensuring their own and others adherence to this policy.
- Escalating any issues that may put the aims of this policy at risk.

Asset Management Strategy

The uncertainty within the gas sector has highlighted the need for Firstgas to redefine what the asset strategy is regarding the gas networks and articulate this into the asset management plans.

To understand what the future networks could look like, Firstgas is developing a set of future scenarios. These scenarios are not forecasts but present a set of credible outcomes as New Zealand transitions to net zero. The outcome for the scenario development will provide Firstgas with a roadmap and signals that will assist with decision making and identify key trigger points. This is a work-in-progress and is expected to be completed within the current financial year. The outcome of this will then allow Firstgas to align the asset strategies to a "least regrets" path until more certainty develops within the sector. This is not expected to be a one-off exercise but a continually evolving approach as New Zealand transitions to net-zero.

Asset Management Objectives

The Asset Management Policy provides a suite of asset management objectives that performance can be measured against. These objectives are related to performance measures discussed later in this appendix and remain consistent with previous submissions.

The objectives are:

- **Safety:** prioritise the integrity of assets to ensure the safety of the people and places affected by operations.
- **Security and reliability**: provide a reliable, resilient and secure service that meets customer needs.
- **Environment**: preserve the environment by operating in a manner that mitigates environmental risks.
- **Compliance**: address and meet all legislative requirements
- **Communication:** communicate The Company's investment plans to stakeholders, particularly the communities that host the assets.
- **Value**: operate in a manner that optimises the long-term financial outcomes for shareholders.
- **Decision making:** balance the needs of competing objectives in a consistent and transparent manner.

H.3.2 Asset Management Plan (AMP)

The AMP captures the key elements of the asset management document suite in a summarised form. It is an important means of clarifying the asset management strategy and approach to managing all assets to internal and external stakeholders. It has also been developed to meet the Information Disclosure obligations under Part 4 of the Commerce Act 1986.

This AMP has been developed with oversight and input from the Commercial and Regulatory Team, which advises on the Information Disclosure and certification requirements.

Approval Process

Once the AMP and associated forecasts have been prepared, reviewed and challenged by Firstgas, it is then reviewed by a Board sub-committee prior to an initial Board submission. When the feedback from the Board has been incorporated, the AMP is submitted to a Board meeting for approval prior to publication.

Key Assumptions

This AMP is based on some fundamental assumptions that underpin the long-term strategic direction and operating environment. These key assumptions are:

- The present gas industry structure will broadly remain the same. For example, it is assumed that over the planning period gas will continue to flow from the Taranaki region to customers located in other parts of the North Island.
- Works will continue to be delivered through a mixture of insourced and outsourced activities. Decisions on what work to outsource is based on capability, cost and resource availability.
- There will be no major disruptive changes to the availability of service providers.
- Consumer demand and expectations will continue to follow long-term trends. While the aim to promote the use of the gas transmission network, a prudent approach has been taken to growth forecasts that are tied to historic trends in the uptake and use of gas in New Zealand.
- There will be no major changes to the regulatory regime that governs operational and investment decisions – for example, through structural changes to the regulatory institutions or the regulatory mechanisms currently in place that allow Firstgas to recover efficient costs.

To the extent possible, all relevant assumptions made in developing this AMP have been quantified and described in the relevant sections. Where an assumption is based on information that is sourced from a third party, that source is noted.

Financial Authority

Each project within the AMP is approved based on a delegated financial authority (DFA) policy. Any changes to project scope requiring additional expenditure triggers further review and a new approval process is required to agree any changes. DFAs set out the limits to what managers are allowed to authorise expenditure. This is reviewed annually.

Table 11 below sets out DFA levels.

Table 11: Delegated Financial Authority Levels

Governance Level	Financial Authority Capex ($000)	Financial Authority Opex ($000)
CEO	$2,000	Budget
COO	$1500	$1500
Engineering Manager	$250	$250
Projects Delivery Manager	$250	$250
Transmission Operations Manager	$250	$250

Challenge Processes

The material included within the AMP reflects the system development plans, life cycle delivery plans, customer connections forecast, and the maintenance strategies. These plans and associated forecasts are prepared in consultation with relevant staff members and engineers.

Reflecting its role as a key stakeholder document, the draft AMP is subjected to a thorough testing process prior to board approval. As part of this process, proposed network expenditure plans are scrutinised and challenged by Firstgas to ensure alignment with the Asset Management Policy and that the plans reflect efficient and effective approaches. Non-network expenditure is also subject to the same process of testing.

Investment Principles

Apart from normal business risk avoidance measures, specific actions to mitigate the risks associated with investing in transmission systems include the following:

- **Act prudently:** where safety is not compromised make small incremental investments and defer large investments as long as reasonably practical (e.g. replace components rather than an entire asset). The small investments must, however, conform to the long-term investment plan for a region and not lead to future asset stranding.
- **Multiple planning timeframes:** produce plans based on near, medium and long-term views. The near-term plan is the most accurate and generally captures load growth for the next three years. This timeframe identifies short-term growth patterns, mainly leveraging off historical trends. It allows sufficient time for planning, approval and network construction to be implemented ahead of new system demand.
- **The medium-term plan looks out 10 years:** capturing regional development trends such as land rezoning, new transport routes and larger infrastructure projects. It also captures changes such as the adoption of new technologies or behavioural trends (e.g. consumers' response to issues such as climate change, increased energy conservation, etc.).
- **Review significant replacement projects**: for large system assets (e.g. compressors), rather than automatically replacing existing end-of-life assets with the modern equivalent, a review is carried out to confirm the continued need for the assets, as well as the optimal size and system configuration that will meet the needs for the next asset lifecycle.
- **Continuously review system performance**: to identify and apply action in respect of where asset performance can be improved.

H.3.3 Asset Management Enablers and Controls

This section describes appropriate oversight and challenges are in place during the development and execution of the plans. Enablers and controls also ensure that resources are available and there is a formal approach to decision making, promoting consistent, repeatable and auditable actions.

Key asset management enablers and control elements include:

- **Capital and operational expenditure guides:** provide the basis for implementing a minimum standard to identify, prioritises, plan, budget, execute, control, and closeout capital expenditure projects and major operational expenditures.
- **Pipeline management system:** demonstration of compliance for audit and certification purposes, and as an overview of the key systems and processes in place for any reader to gain a good understanding of the important components of safe operation.
- **Competency and training:** demonstrate how staff and external parties performing design, construction, operations or maintenance on the transmission system meet the competency requirements as specified by the training matrix.

Capital and Operational Expenditure Guides

The purpose of the Capital and Operational Expenditure guides is to provide the basis for implementing a minimum standard to identify, prioritises, plan, budget, execute, control, and closeout capital expenditure projects and major operational expenditures. Key objectives are to:

- Evaluate Capex projects and major Opex according to the Business Plan, Strategic Planning, and Asset Management Policy and Strategy

- Ensure a complete analysis has been conducted (make vs buy, lease vs buy, rent vs own, outsource vs in-house, should cost modelling, Original Equipment Manufacturer (OEM) vs non-OEM)
- Leverage best practices used by Firstgas and the gas sector
- Provide consistent evaluation of financial and non-financial factors to understand the total value during the life cycle
- Evaluate the risk and exposure of not doing the capital or maintenance project
- Compare alternatives to determine the best solution (e.g. replacing vs repairing equipment, doing the project now vs later)
- Evaluate the project costs on a life cycle basis (long-term value)
- Provide advance sourcing planning to meet long-term objectives and manage supply risk
- Lower costs through consistent integration of business resources and reduce process duplication through integration of financial requirements
- Select the options to ensure the best investment of funds through consistent prioritisation of projects and transparency in decision-making

Pipeline Management System Manual

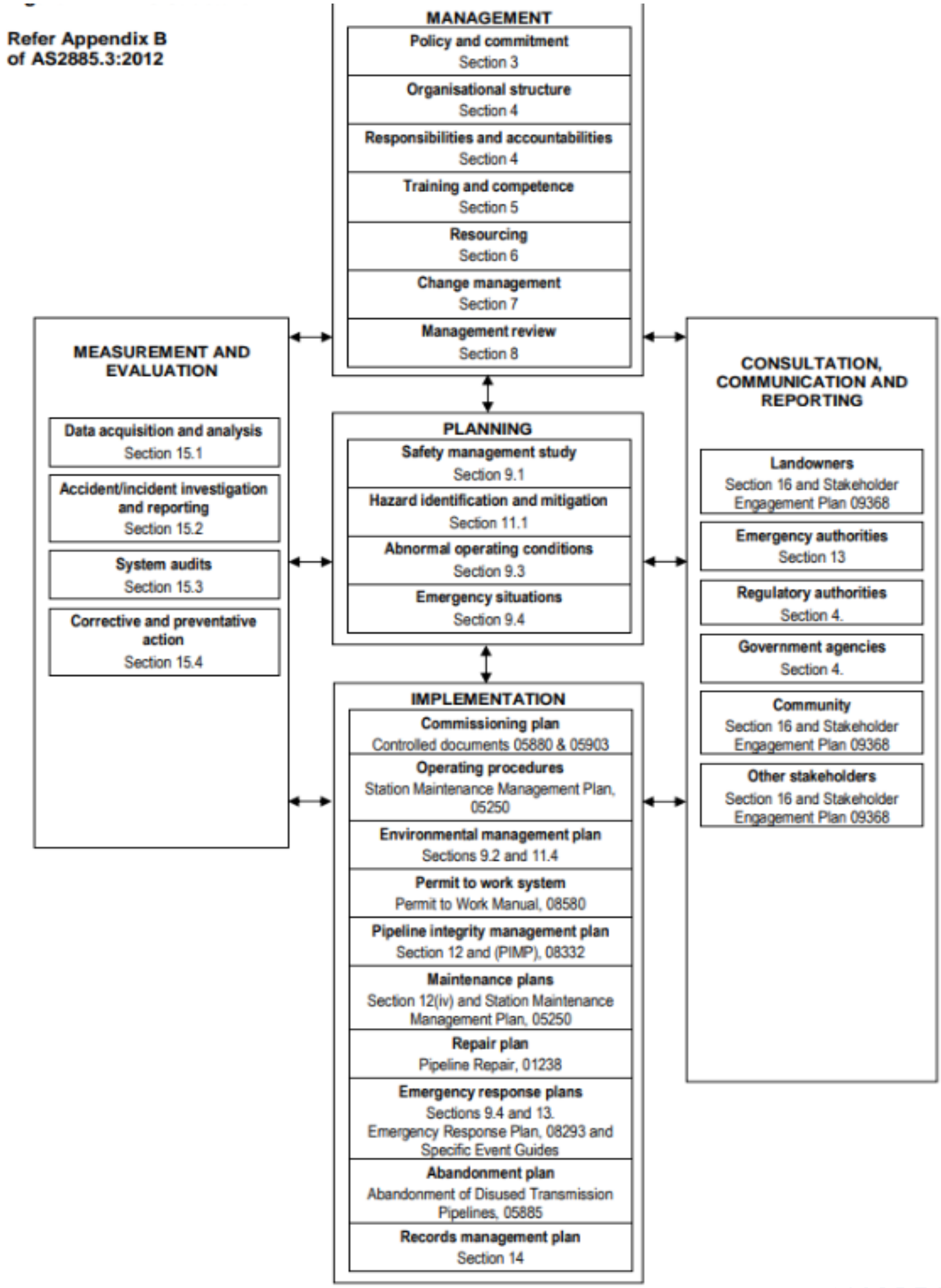
In accordance with the *Health and Safety in Employment (Pipelines) Regulations 1999*. Firstgas has adopted *AS/NZS2885*.x series of standards (the Standard) as the guiding documents for maintaining appropriate standards of safe and sustainable operational practice.

Section 2 of *AS2885.3:2012* requires operators to have a documented and approved Pipeline Management System (PMS). The Standard does not prescribe the structure of the PMS, but sets minimum requirements for content, management, review, approval and communication.

The Standard focuses on the operational aspects of the pipeline, whereas the Gas Transmission Business (GTB) has additional considerations to manage, such as interface with corporate expectations and requirements; commercial aspects of operation; third party services provided to owners of other pipelines etc. The overall management system for the GTB is, therefore, somewhat broader and more complex than that required by the Standard.

The PMS manual serves as a demonstration of compliance for audit and certification purposes, and as an overview of the key systems and processes in place for any reader to gain a good understanding of the important components of safe operation.

Table 12: PMS structure



Competency and Training

All staff or contracted personnel conducting design, construction, operations or maintenance activities on the transmission network must meet the competency requirements as specified by the training matrix[2].

The contractual agreements state that; contracted personnel must meet the competency criteria for all work being performed. Internally, each staff role has a defined set of competency requirements within the position description that personnel performing that role are required to meet. Training requirements are aligned with established competencies in technical operation and maintenance. A training and development plan exists to ensure that personnel involved with the operation and maintenance of the assets are appropriately trained.

H.3.4 RISK & REVIEW

Risk management is a key component of good asset management. The consideration of risk plays a key role in asset management decisions from network development planning, asset replacement through to operational decisions. The assessment of risk and the effectiveness of options to minimise it, is one of the main factors of investment choices.

Key Risk and Review elements include:

- **Risk Management:** core processes are designed to manage existing risks, and to ensure emerging risks are identified, evaluated and managed appropriately.
- **Contingency Planning and Response:** ensures that Firstgas are prepared for and can respond quickly to, a major incident that occurs or may occur on the gas transmission system.
- **Event Management:** provides clear definitions and guidance for all disciplines working for Firstgas in order to ensure a consistent approach in recognising and reporting events.

Firstgas

RISK MANAGEMENT POLICY

Effective management of risk is central to the growth and success of First Gas. We are committed to developing a culture that provides greater certainty by understanding and managing the risks to our business.

The objectives of risk management within First Gas are to:

- Ensure that the Board and Executive Management are aware of the material business risks;
- Proactively identify and manage risk;
- Ensure that risks are understood so that decisions can be informed to allow opportunities to be realised and risk to be managed;
- Provide assurance to our shareholders that processes are in place to manage risk and to meet our commitments.

First Gas will implement a risk management framework across its organisation to ensure that the objectives above can be met.

This framework will require:

- Alignment with recognised industry standards and good practice
- Inclusion of specific legislative requirements where applicable
- Governance processes with regular updates and reports to the Board and Executive Management Team
- All business units and functions to be responsible for developing and implementing their own risk management plans, based on their strategic objectives and operational needs
- All managers to ensure risk controls are in place and effective for operations within their area of responsibility
- Reporting protocols, including the escalation of significant risks to the Executive Management Team and the Board
- All risks to be assigned suitable owners with the appropriate knowledge and authority to manage them
- Regular, routine reviews of all identified risks, including effectiveness of controls
- Appropriate review of existing and new activities to identify new risks
- Training and awareness for all workers so that risk management is well understood
- The development and maintenance of an environment where all workers are comfortable to raise risks as they arise

To ensure that the risk management framework is implemented and maintained we will make the necessary resources available to make sure that this policy is satisfied.

This policy and the associated risk management framework will be reviewed on an annual basis.

Risk Management

Given the potentially severe nature of failures in operation (particularly loss of containment), appropriate and effective risk management is integral to the day-to-day asset management approach.

The asset management information systems and core processes are designed to manage existing risks, and ensure emerging risks are identified, evaluated and managed appropriately. The approach is to seek specific instances where features of the network that should provide resilience, are undermined. In particular, the following assessments are used:

- **Prioritise safety:** risks that may impact the safety of the public, staff and service providers is prioritised.
- **Ensure security of supply:** any works development and lifecycle management processes include formal evaluation of the assets against security criteria.
- **Address poor condition/non-standard equipment**: lifecycle management processes seek out critical items of equipment that are at a higher risk of failure or are non-standard.
- **Need for formal risk review and signoff:** processes include formal requirements to manage the risks identified, including mandatory treatment of high-risk items and formal management signoff where acceptance of moderate risks is recommended.
- **Use of structured risk management:** structured risk capture and management processes are applied to ensure key residual risks are visible and signed off at an appropriate level.

Gas industry codes require risk management to be a continuous process at all stages throughout the lifecycle of the gas transmission network. The nature of the gas transmission business is such that there are many inherent risks. In addition, safety management is one of the highest operational priorities.

The gas transmission business unit has a risk management system that is outlined in a controlled document.[3] This procedure outlines the minimum requirements and ensures consistency in risk management by the business.

As risk severity is defined by the combination of likelihood and consequence, the approach to managing risk focuses on controls and treatments that either amend the likelihood of occurrence or address the severity of the consequences.

The risk management process is not solely about limiting risk by mitigating against adverse impacts but also about fully appreciating and recognising all the risks the business carries and balancing them to take advantage of potential opportunities in an informed manner.

The risk management process is in accordance with the process outlined in *AS/NZS ISO31000 2009.*

Contingency Planning and Response

Network and processes have been designed to be resilient to large events that are outside the realms of the Company's control, such as natural disasters. The following aspects of the asset management approach limit the consequences should these events occur:

- **Multiple control options:** alternative control and emergency management capability available in the event that a primary site is disabled.

[3] 09374 – Risk Management Manual

- **Emergency response plans:** well tested response plans and demonstrated capability to manage significant natural events and widespread damage to the system.
- **Business continuity plans** structured business continuity plans in place to ensure that the functional support aspects of the business are resilient and can support ongoing operations.

Emergency Response Plan

To ensure that Firstgas are prepared for, and can respond quickly to, a major incident that occurs or may occur on the gas transmission system, a comprehensive Emergency Response Plan has been developed. The plan describes the actions required and the responsibilities of staff during a major emergency or incident.

A key component of this plan is the formation of the emergency response management team. This team includes senior staff whose role is to oversee the management of potential loss of and restoration of supply following a significant event. The team is experienced and undertakes exercises at least annually.

Civil Defence and Emergency Management

As a "lifeline utility" under the Civil Defence and Emergency Management Act 2002 (CDEM), Firstgas are required to be "able to function to the fullest possible extent, even if this may be at a reduced level, during and after an emergency". Firstgas are also required to have plans regarding ongoing functions during and after an emergency and to participate in the development of a CDEM strategy and business continuity plans.

The Company participates in CDEM emergency exercises and area meetings on a regular basis to ensure CDEM protocols are understood, as well as to test aspects of emergency plans.

Critical Spares and Equipment

Key to minimising the consequence of any unwanted event involving equipment failure are readily available tools and materials to enable quick restoration to normal operation.

To this end, a stock of spares is maintained for critical components of the gas transmission system, so that fault repair is not hindered by the lack of availability of required parts. Whenever new equipment is introduced to the system, an evaluation is made of the necessary spares required to be retained to support repair of any equipment failures.

Event Management

The Event Management standard provides clear definitions and guidance for all disciplines working for Firstgas in order to ensure a consistent approach in recognising and reporting events, and also provide understanding of what to report and how to report.

Additionally, it provides guidance on investigation methodologies and techniques to identify causes, contributing factors and hazards thereby producing valuable information on lessons learned and future improvements.

The objective of event reporting and investigation is to prevent harm and damage through learning and improving and comply with statutory requirements.

The primary objectives of reporting all events including Learning Events (near misses) are:

- To ensure that any injury occurring or damage sustained receives the necessary treatment or repair.
- To gather initial information during the reporting stage that will be invaluable should further investigation be required.
- To provide valuable learning for the organisation.
- To collect information for reporting to the Authorities.

This will be achieved by:

- Immediate notification of an event
- Gathering good quality information
- A timely investigation process
- Analysis of investigation findings
- Identification and implementation of actions
- Sharing of information
- Ability to record and track actions

H.3.5 LIFE CYCLE DELIVERY

This section explains the approach to managing the gas transmission assets through a lifecycle-based methodology. This approach and the main activities it entails, is discussed during the planning period.

Key Life Cycle Delivery elements include:

- **Asset lifecycle management:** provides an overview of the approach to managing the gas transmission assets
- **Asset replacement and renewal:** discusses approach to renewing asset fleets
- **Asset relocations:** discusses how assets are relocated to accommodate third parties
- **Maintenance:** sets out the approach to maintaining the gas transmission assets
- **Other-network Opex:** discusses additional network related Opex including Network Support costs and expenditure on compressor fuel.

Asset Lifecycle Management

Safety is the key consideration in the design, construction and maintenance of the gas transmission system. Assets are managed in accordance with relevant acts, regulations and industry standards.[4] The transmission assets are designed and built to deliver gas to service levels set out in the Security Standard (GTS-01) and to meet the needs of customers.

To cost-effectively achieve the required level of safety and service, the assets must be kept in good operating condition. This is achieved by replacing, renewing and maintaining the assets. The term asset lifecycle management is used to describe these activities.

The asset lifecycle approach used includes the following main activity phases:[5]

- **Acquire:** this includes investments in new (or larger) assets to ensure demand on the network at appropriate security levels can be met.
- **Operate**: includes real-time network control, monitoring and event response. This involves planning for assets to be safely taken out of service (discussed in this appendix)
- **Maintain**: is the care of assets to ensure they provide the required capability in a safe and reliable manner from commissioning through to their replacement or disposal (discussed in this appendix)
- **Asset replacement**, **renewal and disposal**: includes the replacement of assets with new modern equivalents, investments that extend an asset's useful life or increase its functionality (discussed in this appendix).

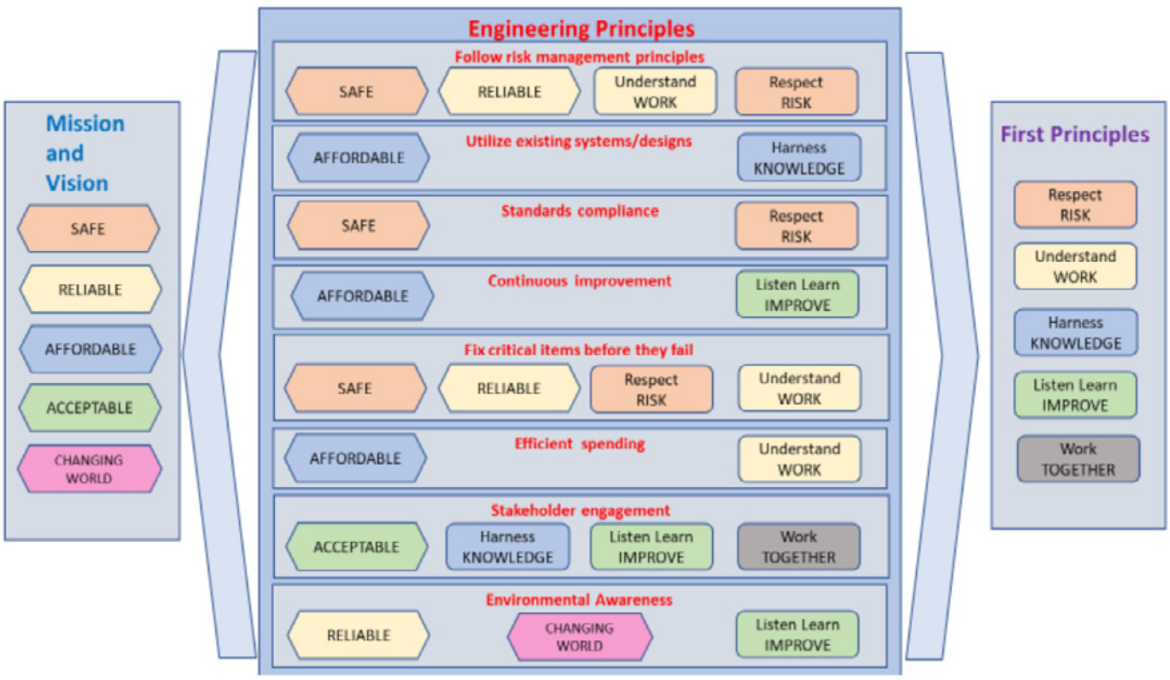
Engineering Principles

To ensure the effective and consistent approach to lifecycle management of the assets Firstgas has developed a set of engineering principles. These outline the approach to all future engineering principles and decisions and is aligned to the Firstgas "Mission and Vision" and general "First Principles" already established.

The strategy defines the following key topics:

- Standards Compliance
- Consistent approach to process and guiding principles and the overall corporate business drivers that set the business direction
- Follows risk management principles and processes
- Commitment to continuous improvement and how the strategy will improve the Firstgas business
- Establish proactive maintenance programmes
- Efficient spending
- Stakeholder engagement
- Environmental awareness

Figure 43: Firstgas Engineering Principles Diagram



Lifecycle Management Strategy

The design of gas transmission assets, in general, cannot conform to standardised designs due the complex and highly variable requirements of major users and downstream networks. Where possible, certain asset components (e.g. isolation valves) may conform to pre-specified standards for specific applications. This is to ensure, wherever possible, that design, procurement, installation and maintenance consistencies and efficiencies are made.

The approach to lifecycle asset management is influenced by a number of factors. These include the need for safety, characteristics of the assets, and external factors such as adverse weather, legislative requirements, customer needs, and commercial requirements.

To ensure that its assets meet the Asset Management objectives over the last few years Firstgas has developed a series of asset class strategies. These are specific to the asset class and define how the assets are to be managed over their lifecycle, and trigger points when assets are to be replaced.

Station Decommissioning

The lifecycle management of assets includes decommissioning unused sites. The gas transmission system installation began in the late 1960s. Since then, the delivery points have received periodic upgrades and renewal of station equipment as technology has developed, or organic growth has triggered an upgrade requirement. Technical evaluations are conducted on equipment for its suitability to be re-used on alternative sites and costs to remove the equipment are evaluated against the ongoing maintenance cost of the site to determine the most effective outcome

H.3.6 Asset Replacement and Renewal

Asset Replacement and Renewal (ARR) is necessary to address asset deterioration and to ensure the system remains in a serviceable and safe condition. As the level of condition deterioration increases, the asset reaches a state where ongoing maintenance becomes ineffective or excessively costly. Once assets reach this stage replacement or renew is considered.

- **Replacement Capex:** includes replacing assets with like-for-like or new modern equivalents.
- **Renewal Capex:** is expenditure that extends an asset's useful life or increases its functionality.

If an asset is identified for replacement or renewal, the original design basis is reviewed for validity prior to confirming replacement. During this review, other alternatives are assessed, such as decommissioning. The availability and feasibility of these options depends on a range of factors. ARR investments are generally managed as a series of programmes focused on a particular asset fleet.

Investment Drivers

Optimisation of Capex requires comprehensive evaluation of the condition, performance and risk associated with assets. From this evaluation, asset renewals are able to be scheduled. In some cases, it may be more efficient to extend the life of an asset beyond normal predicted life by renewing the asset.

There are a number of factors considered when assessing assets for replacement or renewal including:

- Ensuring safety
- Legislative and standards
- Asset condition
- Overall lifecycle cost

Ensuring Safety

A key strategy is to ensure the safety of the public, employees and contractors at all times. This includes making sure inspection regimes effectively identify safety hazards. Protecting the integrity of the network and assets by monitoring and managing the activities of third parties, is also a focus.

There are a number of events or changes that may impact on a pipeline system and result in a change of the identified risk level. Any such changes in design or substantive change to the operating environment can lead to a review of network safety. Such changes can include:

- Urban encroachment
- Geo-hazard
- Third party incidents
- Findings from routine monitoring
- System improvements
- System modifications
- Inspections and audits

The system is designed to meet the Transmission System Security Standard, and includes requirements set out in the Critical Contingency Management Regulations.

Equipment is purchased and installed in accordance with high pressure gas transmission standards to ensure optimal asset life and performance. The design and operation of the system seeks to eliminate safety risks to staff, contractors or the public. This is supported by adoption of safety-in-design principles.

Safety-in-Design

Firstgas are committed to ensuring that all operations do not put employees, contractors or the public at risk. This extends to safety being a key focus of the design phase of the work done. It is at the design stage of creating assets that the greatest opportunity exists to build in safe operability for the whole lifecycle of the asset.

Safety-in-design is about eliminating or controlling risks to health and safety as early as possible in the planning and design stage, so that whatever is designed will be safe to construct, operate, repair and maintain and ultimately, safe to decommission and dispose of at the end of its lifecycle. This concept is implicit in all work practices.

Legislation and Standards

The gas transmission assets have been designed, constructed, and operated in accordance with the following principal acts, Regulations and industry codes.

- Health and Safety in Employment (Pipelines) Regulations 1999
- Health and Safety at Work Act
- Gas (Safety and Measurement) Regulations
- Civil Defence and Emergency Management Act
- Hazardous Substances and New Organisms Act
- AS 2885 Pipelines - Gas and liquid petroleum
- ASME Codes and Standards
- NZS 5259 Gas Measurement Standard
- NZS 5442 Gas Specification for Reticulated Natural Gas
- NZS 7901 Electricity and Gas Industries - Safety Management Systems for Public Safety
- AS 2832.1 Cathodic Protection of Metals
- AS 2312.1 Guide to the protection of structural steel against atmospheric corrosion by the use of protective coatings
- NZS 4853 Electrical Hazards on Metallic pipelines
- NZS 5263 Gas Detection and Odorisation

These acts, regulations and industry codes include prescriptive and performance-based requirements that have been embedded into the suite of design, construction, maintenance and material specification standards. The purpose of these technical standards is to provide a comprehensive reference source for use by all personnel and others involved in the design, construction and maintenance of the transmission system.

The *Electricity Act 1992, Electricity (Safety) Regulations 2010* and associated standards (listed below), as well as other international standards define design and installation requirements for electrical equipment used in explosive atmospheres.

The design, installation and maintenance of electrical equipment in hazardous areas shall comply with *AS/NZS3000:2007* Electrical installations. This refers to:

- *AS/NZS60079.14* - Explosive atmospheres - Electrical installations design, selection and erection.
- *AS/NZS60079.17* - Explosive atmospheres - Electrical installations inspection and maintenance.

Overall Lifecycle Cost

Optimisation of Capex and Opex is a key consideration. This requires comprehensive evaluation of the condition, performance and risk associated with the assets, to provide a clear indication of the optimal time for asset replacement or renewal.

Efficiencies can often result from solutions that allow conventional system investment to be deferred without compromising performance or safety. In evaluating possible solutions, the following factors are considered:

- Estimation of maintenance costs over the remaining life of the asset relative to cost of replacement
- Determine whether a change in maintenance or operational regimes would alleviate the identified issue and whether such a change could be implemented safely
- Feasibility of non-network solutions and demand management techniques
- Scope to leverage off other projects (e.g. growth projects) to gain synergies.

Summary of ARR Capex

Once an asset is identified for replacement or renewal, the prioritisation methodology is applied to determine the ranking of replacement projects. This methodology is based on assessing the criteria giving rise to the need for replacement.

- Risk
- Asset criticality
- Asset health
- Customer needs
- Potential financial impacts

The final project prioritisation list, along with cost estimates, forms the basis of the annual renewal budgets for each fiscal year.

Asset replacement and renewal investment decisions are made within the context of the wider asset management activities (e.g. system development), that ensures investments are optimised across all business objectives and constraints.

H.3.7 Relocations

Existing services are relocated when required as a result of the activities of other utilities, authorities or customers. For example, the development of a state highway in the vicinity of assets may require the relocation of these assets. Relocations are identified following third party works notifications. Typically, asset relocation projects are predominantly funded through capital contributions by the third parties requesting the relocation.

The overarching maintenance policy is to maintain all assets to ensure a safe, efficient and reliable network.

Maintenance Approach

The maintenance approach is designed to ensure that assets safely achieve their expected life and performance levels. Information obtained in the course of maintenance work is used to guide future maintenance programmes and to inform renewal decisions.

A comprehensive suite of asset maintenance standards exist, that describe the approach to maintaining Firstgas asset fleets. There are significant differences required in the approach for different asset types, but as a broad rule the maintenance standards specify the following.

- Required asset inspection frequency
- Routine and special maintenance activities to be carried out during these inspections
- Condition testing that needs to be carried out and the required response to the test results

Maintenance works are delivered by internal resource.

Maintenance Objective

The overarching maintenance philosophy adopted for the asset is to provide timely, quality and cost-effective maintenance services to ensure that assets are maintained to support the required level of safety, reliability, availability, output capacity, and service quality.

During the planning period, the main strategies to achieve this objective are as follows:

- Regularly review the effectiveness of routine maintenance for each asset type and update maintenance standards and activities as required to deliver optimum performance.
- Regularly review the effectiveness of monitoring programmes to identify components that may require more intrusive inspection or could have less frequent inspections.
- Ensure that staff are vigilant in identifying the activities of third parties working near Firstgas assets, and taking appropriate action to ensure the integrity of the network is not compromised.
- Educate the public, landowners and customers through regular communication about the dangers of working near the network.

Activity Drivers

The approach to maintenance is influenced by a number of factors. These include the number, type and diversity of the asset fleets, their condition and age, legislative requirements, environmental factors and third-party activity.

A number of considerations are accounted for when setting maintenance requirements:

- **Pipeline Certificates of Fitness:** prescribes mandatory conditions for the performance of operations and maintenance. Other mandatory requirements are included in various acts, Regulations and Standards.
- **Industry Practice**: maintenance practices have largely evolved over the past 40 years. *Australian Standard 2885.3* covers gas pipeline operation and maintenance and is the main reference for these activities. Other obligations fall into the category of good industry practice and are found in various New Zealand, Australian and international standards and codes.

- **Fault Analysis**: root cause analysis is undertaken when significant defects occur. This is supplemented by fault trend analysis. If performance issues with a particular type of asset are identified, and if the risk exposure warrants it, a project will be developed to carry out the appropriate remedial actions. The maintenance strategy is periodically reviewed and the findings from root cause analysis and fault trend analysis are used during the review process.
- **Asset Availability**: Assets are maintained to a level that maximises the availability of the equipment for remote and unmanned operation.

Maintenance Standards

Firstgas asset maintenance programmes are prepared through a collaborative approach involving the Asset Management, Engineering, Transmission Operations and Specialist Services teams who carry out maintenance and inspection in the field. Reflecting the above drivers, overarching maintenance programmes have been developed for pipelines and stations. These are set out in the following documents:

- Maintenance Strategy Document
- Pressure Equipment Management Plan
- The Pipeline Integrity Management Plan (PIMP)

These documents outline what is necessary to maintain the asset at the required levels of service, while minimising lifecycle costs and risks.

They define the required frequency of inspection and maintenance for each asset class based on statutory requirements, operating context, knowledge of equipment performance and manufacturers' recommendations. They form the basis of the *Appendix K - Asset Maintenance Schedule*.

This approach is reviewed and updated based on any new information. The Transmission Operations Team contributes to, and forms an integral part of, this continuous improvement process. Defects identified during asset maintenance and inspections are recorded and prioritised based on risk assessment for remedial works. Maintenance priorities are based on risk and safety criteria.

Urban Encroachment

An increasing trend is urban encroachment on Firstgas assets. When the pipelines were constructed, the routes and delivery points were located in undeveloped areas where possible.

Over the years there has been significant urban development growth in a number of areas resulting in gradual encroachment on these assets. These developments have the potential to increase the likelihood of negative consequences to assets. The developments are reviewed through impact assessments on an individual basis, to determine the best course of action to ensure the safety and reliability of the system.

Impact assessments may result in:

- Re-allocation of pipeline location class categorisation
- Additional Pipeline protection - e.g. concrete slabbing over the pipeline
- Realignment of the pipeline
- Increased maintenance and monitoring of the assets

Information Disclosure

For the purposes of the AMP the maintenance work is categorised into the following Information Disclosure categories.[6]

- Routine and Corrective Maintenance and Inspection
- Service Interruptions, Incidents and Emergencies

These are discussed below.

Routine and Corrective Maintenance and Inspection (RCMI)

Immediately after new assets are commissioned the RCMI programme begins. As an asset ages and its condition worsens, the cost of corrective repairs to maintain fitness for purpose will escalate until it becomes more cost-effective to decommission or replace it. On-going condition monitoring is used throughout the asset's life to identify when the asset should be decommissioned.

Routine and corrective maintenance and inspection activities include the following:

- Pipeline patrols, inspection and condition detection tasks and maintenance service work.
- The co-ordination of shutdowns of station facilities, restoration of supply along with the capture and management of all defined data.
- Painting and repair of buildings and asset enclosures, removal of decommissioned assets, one-off type inspection and condition detection tasks outside of planned maintenance standards.
- Repair of assets identified from programmed inspections or service work.
- Advanced investigative and corrective technologies to extend machinery life are used to determine respective maintenance plans on the assets, such as:
- Root cause failure analysis
- Borescope inspections
- Alignment and balancing
- Installation / commissioning performance verification

Taking all of the above into account, maintenance strategies and plans are developed. These determine maintenance activities and frequencies. The frequencies defined in the maintenance plans are encapsulated in the ERP. This system provides schedules and frequency guidelines for maintenance on the assets.

New technologies are being used more frequently. The advantage of these technologies is that condition assessment can be undertaken without disturbing normal operation. Technologies typically employed are vibration analysis, thermography, tribology, ultrasonics, metrology, oil analysis, water bath heater water sampling or computerised calibrations. New technologies will be evaluated for use within maintenance routines as they become proven across various industries.

The maintenance strategy and PIMP describe the approach to maintaining and inspecting various asset types. A comprehensive suite of maintenance and inspection check sheets support the delivery and monitoring of the maintenance strategy.

6 Firstgas does not currently assign any expenditure to the ARR Opex category.

Pipelines

Detailed philosophy and guidelines for pipeline maintenance and renewal are contained in the PIMP. The PIMP outlines the pipeline monitoring and maintenance activities to be undertaken to support the safe and reliable operation of these assets.

The PIMP is reviewed annually and considers monitoring data and pipeline activities from the previous year. Any changes in risk are identified and, as a result, monitoring and maintenance activities are updated to reflect the new risk level.

Risks associated with the pipelines encompass a wide range of threats, which can be broadly categorised as:

- Third party interference
- Corrosion
- Geo-hazards (flooding, earthquakes, slips, etc.)

There are a number of events or changes that can impact the pipeline system that may result in a change of the identified risk level and hence maintenance routines. Such changes include:

- Urban encroachment
- Pipeline related incidents
- Findings from routine monitoring
- System improvements
- System modifications
- Inspections and audits

Any required changes to routine maintenance activities identified by the SMS are incorporated into the PIMP and corresponding maintenance schedules.

Any required non-routine activities identified by the SMS are registered in the corrective actions database or assessed, prioritised and assigned in the Asset Risk Register.

A pipeline integrity management software application is used for the management and analysis of pipeline condition data. The system employed is the Rosen Asset Integrity Management System (ROAIMS). This system has improved the ability to record and store data obtained from the routine maintenance and inspection of the pipelines. The system provides enhanced capabilities for asset performance monitoring, corrosion growth rate analysis and advising changes to maintenance activities.

Stations

The philosophy and guidelines for maintenance of station assets is outlined in the Maintenance Strategy. This document describes the general approach to maintenance, maintenance management model, KPIs, and additional strategy elements including spare parts management. In conjunction with the Maintenance Strategy a risk-based work selection process has been adopted to prioritise station maintenance for routine and non-routine maintenance activities. This process allocates a risk score to maintenance activities in order to facilitate prioritisation where required. Maintenance at station assets is scheduled in a maintenance plan and monitored through the Computerised Maintenance Management System (CMMS).

All pressure equipment forming part of the high-pressure gas transmission system is subject to the requirements of the *HSE Pipelines Regulations*. As a primary means of compliance to these regulations, Firstgas have adopted *AS/NZS2885*. As pressure vessels fall outside the scope of these regulations, inspection and maintenance is carried out of vessels in accordance with:

- *AS/NZS3788:2006* Pressure Equipment In-Service Inspection
- Firstgas document number 06146 - Pressure Equipment Management Plan

These documents define the requirements for inspection intervals, competent person requirements, non-conformance reporting and standards to be applied.

Collecting asset condition data allows accurate assessment of the health of individual assets on an ongoing basis. By tracking this information over time and assessing this in conjunction with reliability performance, the effectiveness of the renewal and maintenance investment can be continually assessed and refined. Due to the aging profile of Firstgas assets, a strong emphasis is placed on condition monitoring to determine current condition and expected remaining life. Analysis of this data will provide better information to allow for asset renewal and replacement programs in future AMPs.

The CMMS is used to collate information about asset condition and is used to analyse data trends to assist in informing decisions on maintenance activities.

Service Interruptions, Incidents and Emergencies (SIE)

- The occurrence of SIEs will result in the need to carry out activities to understand the nature of the SIE and rectify asset failure or damage to assets caused by unplanned or unforeseen circumstances. This may include the following activities.
- Safety response and repair (or replacement) of any part of the asset damaged due to environmental factors or third-party interference.
- Response to any fault at a station where safety or supply integrity could be compromised.
- Remediation or isolation of unsafe network situations.

Every reasonably practicable precaution is taken to prevent third party interference with pipelines and carry out rigorous inspection and maintenance practices. However, experience and history has shown that emergency situations arise from time to time. In most circumstances pipeline integrity breaches do not result in catastrophic failure or rupture of the pipeline and suitable repair methodology and techniques can be applied. In more serious cases pipelines may have to be isolated and sections of pipeline replaced.

Delivery Model

A mix of insourcing and outsourcing approaches for field work delivery are used within Firstgas. This approach is currently considered appropriate and is driven by the concept of having scarce and specialised skills supplied internally. Where the skill set is more broadly available and a competitive market exists, then outsourcing is preferred.

Transmission field maintenance is an insourced activity. Transmission maintenance related skills are uncommon in New Zealand (with Firstgas being the only gas transmission company). In order to ensure work delivery and development of skills ownership for providing the resource internally has been taken.

Some capital project construction is outsourced and a number of other technical roles to a group of ‘service providers’. Sustainable and effective relationships are built with these providers through appropriate commercial arrangements. This approach enables Firstgas to retain core engineering competencies in-house, while leveraging the expertise and resources of service providers. While this approach has several benefits, it requires effective alignment in respective aims and incentives.

Maintenance Delivery

Asset inspections and maintenance work is delivered by the Transmission Operations and Specialist Service Teams in accordance with the applicable standards and inspection schedules for each class of asset.

The resources employed by the teams are mainly in-house and are supplemented by the use of external contractors to balance workload requirements. The teams are responsible for planning and scheduling maintenance requirements and ensuring that sufficient competent resources are available to deliver against requirements.

Progress against the maintenance schedules and the associated maintenance costs are monitored on a monthly basis.

H.3.8 Other Network Opex

Additional Opex is incurred during the day-to-day running of the gas transmission system. This expenditure is included under the following categories which are described in more detail below.

- Network Support
- System Operations
- Compressor Fuel
- Land management and associated activity

Overall Opex for the planning period is anticipated to be broadly consistent with average historical spends.

Network Support

Network support Opex relates to expenditure where the primary driver is the management of the network. These expenses include the following activities:

- Asset planning, including preparation of the AMP, load forecasting and network modelling
- Network and engineering design (excluding design costs capitalised for capital project)
- Network policy development
- Standards and documentation development for network management
- Network record keeping and asset management database maintenance including GIS
- Outage recording
- Connection and customer records/customer management databases
- Customer queries and call centre
- Operational training for network management and field staff
- Operational vehicles and transport
- IT & telecoms network management including IT support for asset management information systems
- Day-to-day customer management
- Engineering and technical consulting
- Network planning and systems audits
- Logistics and stores, easement management, surveying of new sites to identify work requirements

- Contractor/contract management
- Transmission operator liaison management
- Network related research and development

The expenditure forecast is based on historical trends, a bottom-up review of network costs and operational experience. Specific provision for engineering studies is required in the following areas:

- Gas contamination occurs from time to time so improved analysis, monitoring and management is required to better understand causes and mitigations. This may include a review of the effectiveness of the current coalescer fleet
- Ongoing development of the maintenance strategy and associated efficiencies
- Asset records/data and associated maintenance and reliability information improvement to assist asset management processes
- Ten yearly remaining life review and retrospective fracture control plans for *AS2885* compliance
- Development of Stress Corrosion Cracking Management Plan
- Piggability investigation and review.

System Operations

System Operations Opex relates to expenditure on office-based system operations, and includes:

- Control centre costs
- Critical system operator activities including OATIS costs
- Outage planning and notification
- Production facility liaison.

Compressor Fuel

All gas turbine and reciprocating engines, with the exception of the Henderson compressor station, are fuelled by gas. Compressor fuel is purchased under an agreement with a gas retailer, following competitive tenders that are undertaken periodically.

The Opex forecast for compressor fuel is based on historical requirements and includes the operational costs for the Henderson compressor station.

Actual compressor costs will be dictated by the compressor utilisation programme. Gas is often transported over long distances, which causes gas pressure to decrease due to frictional losses in the pipeline. Gas pressure is increased by compressors to ensure that the required gas pressure and quantity is delivered to the extremities of the system.

Land Management and Associated Activity

With regards to land management and activities in the area of the pipelines, the Land and Planning Team carry out the below activities.

- Provision of 24/7 one-call number.
- Responses to “Dial Before You Work” requests including coordination of pipeline locations and easement work permits and advice.
- Works adjacent to pipeline proposal reviews.

The Pipeline Integrity Team have formalised the process by which proposals for activities on or adjacent to the pipeline easement are considered. Response to enquiries is provided in accordance with Firstgas document Communication and Assessment of Works Adjacent to Pipelines.

In addition, the Field Services Team conduct the following field activities:

- location of pipelines before and during works by third parties
- issue of Pipeline Easement Work Permits to third parties
- stand over of works adjacent to pipelines by third parties.

Pipeline Awareness

The number of reported incidents and unauthorised activities across Firstgas owned and managed pipelines is relatively high when compared against international pipeline systems. This is due to a combination of intensive agricultural land use along the pipeline routes, together with high rates of discovery and reporting.

Some of the routine pipeline awareness techniques used as a part of the pipeline safety awareness plan include:

- signage replacement
- landowner visits
- roadside “Dial Before You Work” signs in rural areas
- fence post painting (indicating route of pipeline)
- landowner liaison through six-monthly postal correspondence
- communications with councils to raise awareness of the pipeline and their obligations regarding land development
- periodic newspaper advertisements
- yearly postal communications with contractors and trade displays
- pipeline safety seminars and safety presentations to contracting companies.

H.3.9 Asset Management Support

This section advises the functions and capabilities that support the day-to-day asset management activities. It describes:

- **Non-network assets**: including Information and Communications Technology (ICT) systems and office facilities.
- **Business support**: activities that support the gas transmission service.

H.3.10 Non-network Assets

This section includes non-network assets. It explains the approach to delivering IS/ICT capabilities and managing associated assets. It also considers other non-network assets (e.g. buildings).

H.3.11 INFORMATION SYSTEMS (IS) ASSETS

Firstgas continues to develop and implement Information Systems to improve organisational capability: These include:

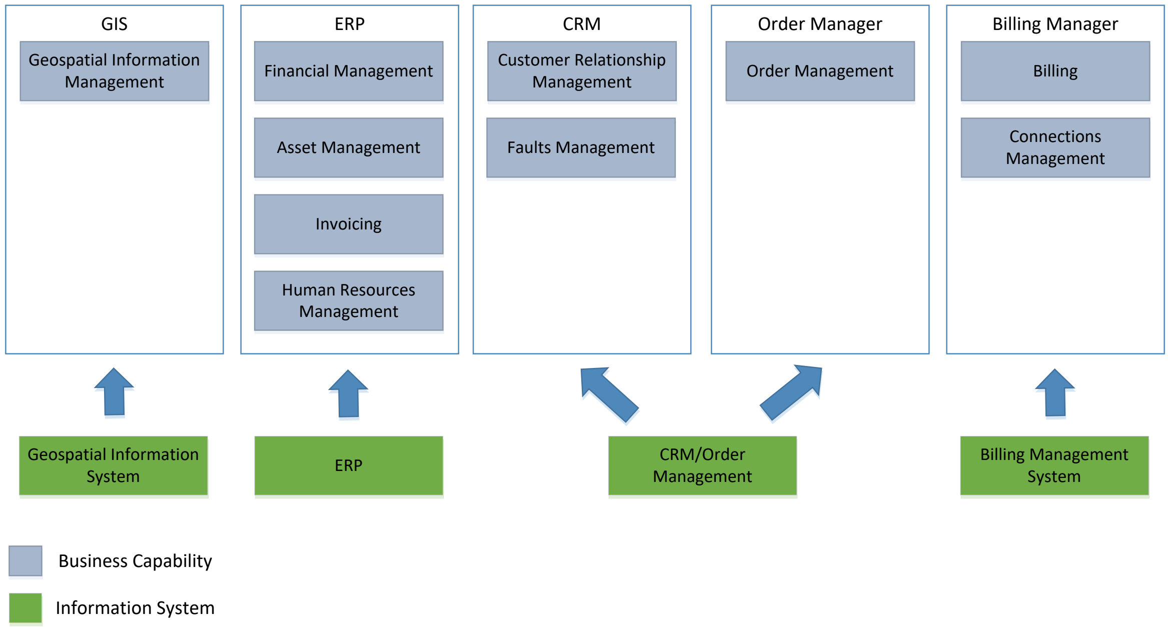
- X-Info Suite: Land & Planning management toolset
- Solufy Akwire: field resource scheduling tool that interfaces with Maximo
- ESRI ArcGIS: a geospatial application that has the capability to interact with multiple asset delivery applications providing a complete data reporting view for the transmission assets data, enabling a one-stop-shop for all GIS data.
- Project Server Online is the collaborative project management tool.

The ICT systems and functions include:

- **Core network related systems**: support capabilities that manage information directly relating to Firstgas network assets and their operation and management
- **Supporting network related systems**: are smaller systems that support capabilities that manage information that directly relates to assets and their operation and management
- **Supporting ICT infrastructure systems**: support the integration and operation of both the core network and supporting network related systems.

Figure 43 below illustrates the relationship between the business functions and processes - hereafter referred to as business capabilities - and the core network related systems.

Figure 43: Business Capabilities and Core Network Related Systems



Firstgas will continue investing over the next few years to ensure the systems are being used effectively and efficiently. Invest in digital workspace transformation and information management strategies are a particular focus.

H.3.12 INFORMATION AND DATA

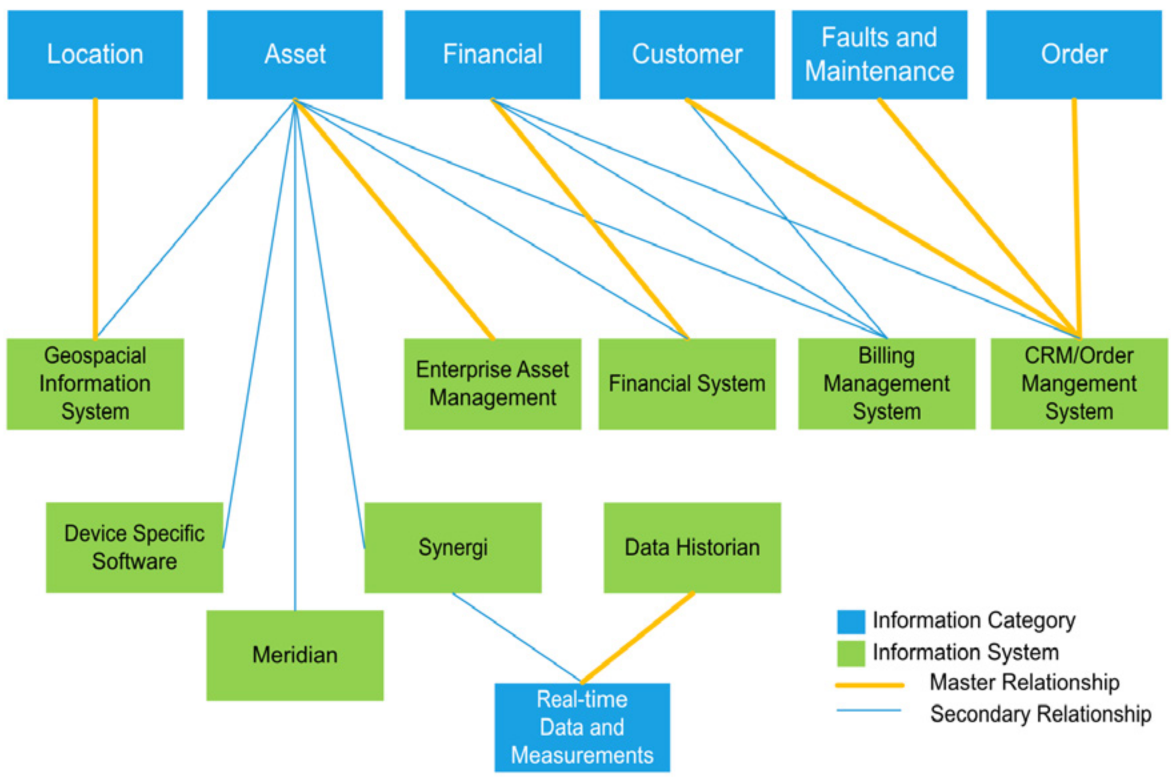
The network and supporting network information systems manage data that is necessary for the effective day-to-day operation of the network assets and the ongoing planning activities relating to those assets.

The information can be divided into several categories:

- Asset (e.g. type, size, installation date, operating/maximum pressures)
- Location
- Customer
- Order
- Financial
- Faults and maintenance
- Real-time data and measurements.

These information categories managed by information systems are shown in Figure 44 below.

Figure 44: Information and Systems Relationships



Information Systems Strategic Plan (ISSP)

The ISSP aims to ensure Firstgas develops capabilities enabling the support of planned asset management changes over the planning period, including:

- Enhancing asset management analysis capabilities
- Supporting increased work volumes on the networks
- Providing real-time information to customers, including through new information channels

- Enhancing the way work is delivered to service providers.

Over the planning period, it is recognised the range of available options to deliver ICT capability will shift and evolve rapidly. Strategies and plans are designed to maximise flexibility in a changing environment.

As a lifeline utility, Firstgas recognise that system resilience is a fundamental expectation.

System architecture must be developed on industry accepted standards for cyber security in an increasingly connected communications landscape. Over the planning period it is paramount that ICT assets are:

- **Flexible**: built on technologies forming a solid central platform that allow rapid development of new capabilities around the margins
- **Scalable:** to accommodate increased data processing/storage and accessible to ensure customers and internal users have real-time access to the information they need and can rely on the quality and security of that information
- **Resilient:** to maintain 'lifeline' utility levels of reliability, ensuring systems are resilient, reliable and responsive, designed with multiple layers of redundancy matched to the criticality of the capabilities they support.

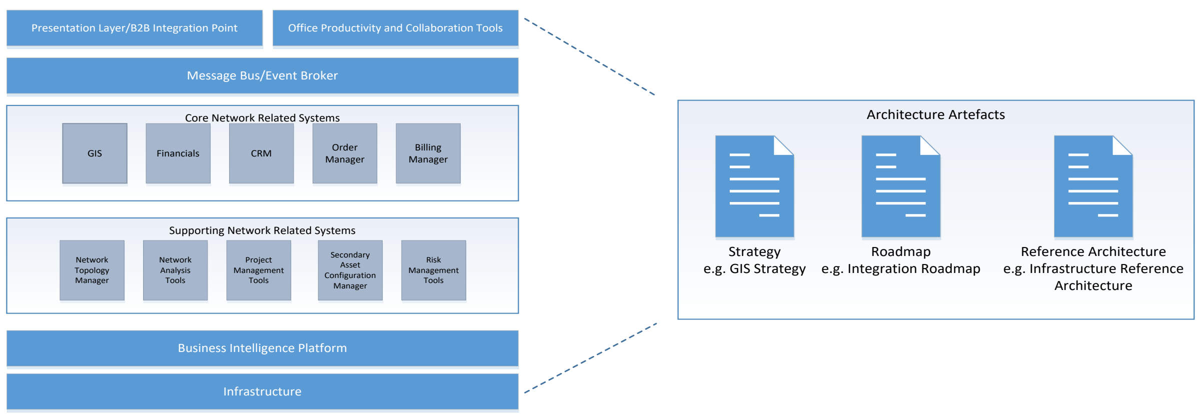
ICT Investments

This section describes the approach to investing in ICT assets that support the asset management functions and the cost of maintaining these services.

It includes investments in ICT change initiatives and network related ICT. It covers the ICT programmes and projects that ensure processes, technology and systems help deliver asset management objectives.

Each component within technology architecture has a collection of supporting architecture documents. These documents are referred to as 'Architecture Artefacts'. They are used to define the strategy, roadmap, and detailed reference architecture specific to each component.

Figure 45: Architecture Artefacts



These 'Architecture Artefacts' are used to inform the investment planning for each information technology system and infrastructure component. Financial modelling is also used in addition to these artefacts to ensure that ICT investment decision-making considers financial constraints such as total cost of ownership and IS asset depreciation.

Furthermore, expenditure forecasts are informed by historical costs, expected unit cost, and price trends. Firstgas have worked with suppliers to determine unit costs for current technologies or their likely replacements. Due to the rapidly changing nature and relatively short lifecycle of ICT related hardware and software it is difficult to determine accurate unit cost estimates for products and services more than two years out.

To develop 10-year expenditure forecasts it is assumed that software costs will progressively move from Capex to Opex as software providers shift to the software as a service model. It was also assumed that hardware costs are likely to be stable over the next 10 years on a like-for-like basis.

Main ICT Systems

Table 13: Key Systems

SYSTEM	DESCRIPTION
Finance and Operations 365 (FinOPs)	Finance
Maximo	Enterprise Asset Management
Akwire	Field Resource Scheduler
ESRI ArcGIS	Geospatial Information System
X-Info	Land & Planning Management
Microsoft Dynamics CRM	Customer Relationship Management
Axos	Billing

Finance and Operations

The Financial Systems Strategy is to ensure that all financial solutions are fit for purpose and cost effective to maintain. This will allow us to leverage asset information without the systems becoming overly complex and costly. Finance and Operations 365 is a Microsoft product that provides integrated financial management and operational capabilities. FinOPs 365 was selected as the financial management system and implementation of this system occurred in FY2021

Enterprise Asset Management (EAM): Maximo

To meet organisational objectives, the focus on capturing accurate data at source and making information accessible to the business with tools that allow us to leverage value and improve performance is paramount to informing the right business decisions.

In line with the objective of optimising lifecycle asset management capability, the EAM and associated business processes have been designed to hold the planned maintenance schedule for each asset, according to the relevant engineering standard. It also captures transactional information against each asset record, including that gathered through inspection activities, maintenance activities and defects lists.

The format for transactional information entered into the EAM is defined by the engineering standards, including maintenance standards. Works management is enabled by deriving inspection and maintenance schedules from the information held in the EAM, in line with operational and engineering standards and supported by asset engineers. The EAM includes the functionality provided by a computerised maintenance management system.

Capturing field data regarding maintenance activities is carried out using both a paper system with data inputted by administrative staff and an electronic based system comprising of tablet devices and associated software linking between tablets and the EAM.

The EAM includes four management modules in an enhanced service-oriented architecture. It allows the use of asset information to achieve customer & regulatory outcomes, increase operational efficiency and to identify opportunities for disciplined growth and improvements in cost efficiency. These modules are:

- Asset management
- Work management
- Service management
- Contract management.

Geographical Information System (GIS)

The ESRI ArcGIS now holds both the distribution and transmission asset data. GIS is the master asset register for below ground pipeline assets and includes geospatial, technical, hierarchical, spatial, contextual, connectivity, CP and land management data. The locations of assets generated and recorded in the EAM are also recorded in GIS for cross referencing.

GIS provides a computerised mapping system, which shows the location of all assets against land-based data provided by Land Information New Zealand via CoreLogic. Its primary purposes is to provide pipeline information for the BeforeUDig service and to support Pipeline Integrity Management System (PIMS) and demand modelling systems.

A key piece of equipment used in the field to capture the location of assets is GPS receivers. GPS uses satellites to establish an accurate position and coordinates on the earth's surface and allows data to be captured about the asset loaded into the GIS.

Customer Relationship Management (CRM)

The CRM Systems Strategy ensures that all CRM solutions are used "as designed" with the minimal amount of customisation. Such solutions will allow Firstgas to better serve customers without the systems becoming overly complex and costly and will enable interaction with customers effectively and efficiently to achieve customer and regulatory outcomes, increase operational efficiency and identify opportunities for improvements in cost efficiency.

Billing (Axos)

The Billing Systems Strategy ensures that the billing solution is "fit for purpose" for the billing requirements of the business. "Fit for purpose" Billing Management Solutions will allow better control billing processes without the systems becoming overly complex and costly. It will enable the effective and efficient execution of billing processes to achieve customer and regulatory outcomes, increase operational efficiency, to identify opportunities for disciplined growth and improve cost efficiency.

Open Access Transmission Information System (OATIS)

OATIS is the pipeline operation system which facilitates third party access to the transmission system. OATIS balances pipeline receipt and delivery nominations, processes pipeline metering information and performs a myriad of essential pipeline tasks.

The system is considered to have reached the end of its life, and replacement of the system will be required within the planning period.

Training Manager

Training and competency recording are maintained in Maximo. This enables planning, budgeting and resourcing capability for internal and external courses. Industry and regulatory training are also able to be recorded and reported on. It allows for local configuration of set up so it can be customised to business requirements aligning with the organisational structure.

Data Quality Management

Asset data is largely captured and maintained through an as-building process. These activities are controlled by asset data standards, business rules, work instructions and the relevant provisions of any contractual agreements with service providers.

Asset data standards determine which assets are captured in the asset management information systems, the attributes of those assets recorded, and the transaction types required e.g. records of planned inspections, faults and defect data.

Data is gathered and uploaded in accordance with Firstgas standards and used in formulating maintenance plans or strategies on the basis of the information captured.

H.3.13 OTHER NON-NETWORK ASSETS

This includes all other Capex not encompassed within the direct network or ICT Capex. It comprises the following main expenditure types:

- **Offices and facilities**: costs related to the relocation, refurbishment and development of office buildings and facilities
- **Vehicles**: includes investments that maintain the motor vehicle fleet
- **Minor fixed assets**: costs of ongoing replacement of office equipment including workstations, laptops, mobile phones and peripheral devices.

Offices and Facilities

The expenditure during the planning period mainly relates to the refurbishment of the New Plymouth offices. The main drivers are the improved productivity and effectiveness of a fit for purpose office. The current office is overdue for major refurbishments. Refurbishment costs are based on estimates of the likely 'fit-out' (e.g. interior partitioning and office furniture) costs.

Vehicles

Firstgas prefers to purchase its vehicle fleet as it makes better strategic sense to own a vehicle directly where certain towing abilities or specific plant equipment are required.

Minor Fixed Assets

All employees are provided with a standard workstation setup that includes a desk, chair, storage, PC and communication equipment. Minor fixed assets are classified as the following:

- Desktop and laptop hardware
- Monitors and screens
- Video conferencing equipment
- Other peripherals (e.g. printers and scanners).

Expenditure is driven by the need to provide staff with the tools necessary to carry out their roles efficiently and to leverage business improvements (such as new ICT systems) and increase staff mobility and collaboration.

H.3.14 Non-network Capex Expenditure Allocation Methodology

Non-network Capex is allocated between the transmission and distribution businesses based on factors such as size of asset base and staff headcount.

Business Support

People across the business play a central role in managing all Firstgas assets. Ensuring enough people with the right competencies is essential to achieve asset management objectives over the planning period.

H.4.1 Business Support Expenditure

Firstgas directly employs about 282 people across the gas businesses (who also support the distribution assets). Many more field staff and engineers are employed through service providers. To support asset management teams, a number of corporate support functions exist. These include customer management, finance, and ICT. These functions either directly or indirectly support the transmission side of the business as set out in the examples below.

- **Finance**: financial management, management reporting and analysis and operations to support the business.
- **Human resources**: attracting and retaining capable and effective people, managing competency development and ensuring a positive working environment.
- **Health and safety**: leadership and coordination of safety across the company.
- **Legal and regulatory**: compliance with statutory requirements, including regulatory and environmental obligations.

This expenditure is largely driven by the human resource requirements. A large portion relates to direct staff costs. The other main elements are insurance, legal, audit and assurance fees (primarily to support regulatory compliance), office accommodation costs and travel costs.

Forecasts have been developed from the bottom up for each individual business unit by the executive manager responsible for that business unit. Each individual executive manager regularly assesses the resource requirements for their business unit/s.

- **Salaries and wages**: the majority of the costs are related to internal staff salaries and wages for permanent positions.
- **Staff costs**: the next major driver is staff costs which include training costs, travel, meals and accommodation, recruitment costs and mobile phones etc. These costs are driven by headcount and to some degree technology.
- **Professional and legal advice**: professional advice is sought for a wide range of purposes, including supplementing internal capabilities in legal, tax, internal audit, regulatory, and ICT teams with specialist skills and advice as required.

As a regional employer, it can be difficult to attract specialist professionals, particularly from overseas, who are less familiar with NZ locations. This means Firstgas needs to remain competitive with employee benefit packages.

These investments in people are essential to operate as an effective company and to ensure that the Firstgas workforce is appropriately skilled and qualified.

ICT Opex

ICT Opex covers ICT costs associated with operating the business. More specifically it covers software licensing, software support, data and hosting, and network running costs. These costs are driven from the need to support corporate and network operations with appropriate technology services. It is driven by the following factors:

- Increased technology capability requirements as a standalone business
- System complexity
- Increases in the number of staff and contractors
- Software audit requirements from vendors are met ensuring compliance with vendor End User Licensing Agreements
- Ensures access to appropriate levels of software support from vendors and access to bug fixes and maintenance packs
- Lifecycle stage of IT assets and data needs of the business.
- SaaS – Software as a Service costs

The software industry as a whole is moving to subscription 'pay-as-you-go' models due to cloud-delivered software and technologies

Forecasts are based on the most accurate information obtainable from suppliers and service providers and on the current technologies available and required scale to meet the Company's needs.

H.4.2 Business Support Expenditure Over the Planning Period

The Business Support Opex forecast includes expenditure related to the functions that support the gas transmission business. It includes indirect staff costs and associated expenses advice. The other material elements are office accommodation costs, legal and insurance costs.

A portion of the Business Support Opex is allocated to the gas distribution business in accordance with the cost allocation policy.

H.4.3 Business support Allocation Methodology

- The allocation of Business Support costs to the transmission and distribution businesses is based on a combination of the following factors:
- The first is applied to expenditure that has a relationship with the assets (such as ICT systems) and is an allocation on a proportion of RAB basis
- The second is related more to supporting the people in the business (such as-building costs) and is proportioned on the basis of the relative headcount working in each particular business.
- The third allocation applies to other or miscellaneous spend and is an average of the first two methodologies.

Performance Measures

Firstgas performance measures are specific asset operational, equipment reliability and other compliance measures. The following measures together with a summary of the tactical initiatives that will help us achieve them. A key premise for the AMP is that existing reliability and supply quality levels will be maintained. Accordingly, these targets are presently set at a constant value for the current AMP planning period. Performance against these targets is also discussed.

Where appropriate the measures have been developed to align with the definitions developed by the Commerce Commission for Information Disclosure.

H.5.1 Safety

Firstgas routinely monitor health and safety performance of all personal and companies engaged in its business. Firstgas has a strong reporting culture where all incidents are reported and reviewed weekly to ensure the appropriate level of incident investigation and ownership follows.

Table 14: Safety - historical performance

	FY2018	FY2019	FY2020	FY2021	FY2022
Lost Time Injuries	0	0	0	0	0

Historical performance targets have been met, however Firstgas continues to increase its focus on critical risks, particularly those that can result in serious injury or fatality. Safety initiatives include the following:

- **Collaboration:** Firstgas works collaboratively with all partner service providers. For example, step changes are made in works planning to produce plans earlier and improve their stability. This creates an environment where staff and service providers can operate more safely. Firstgas are also working with service providers to develop better policies, work practices and reporting disciplines.
- **Asset management framework:** drives safe outcomes. Safety by Design principles have been implemented and applied across the full asset lifecycle. All workers are trained in these principles.
- **Communications:** Firstgas are supporting health and safety committees to initiate meaningful projects, allocating resources to regularly communicate to workers, and setting up reward programmes to recognise individuals' behaviour.
- **Safety systems:** providing service specifications and policies to service providers ensures best practice understanding, reviewing work management policies and providing an improved and transparent public safety management system.

Lost time Injury Target

Zero lost time injuries

H.5.2 Security and Reliability: Response Time To Emergencies (RTE)

Firstgas takes the safety of the public and its work force very seriously and aims to attend to emergencies occurring on its transmission system as soon as practical to prevent any damage or harm to the public, employees, contractors and neighbouring properties.

Table 15: RTE - historical performance

	FY2018	FY2019	FY2020	FY2021	FY2022
Proportion of RTE within 180 minutes	100%	100%	100%	100%	100%

RTE TARGET

Respond to all gas transmission emergencies in less than 180 minutes

H.5.3 SECURITY AND RELIABILITY: UNPLANNED INTERRUPTIONS

In general, supply interruptions can be categorised as either planned or unplanned. Planned interruptions may be required for us to carry out planned work (such as connecting a new customer) in a timely manner. Planned interruptions are usually carried out at a time to minimise inconvenience to consumers, after consultation with them.

Unplanned interruptions are usually the result of equipment failure or other events outside Firstgas Group's control. All reasonable and prudent steps are taken to prevent such events. If an unplanned interruption should occur Firstgas endeavours to restore supply as soon as practicable consistent with overriding health and safety obligations towards staff, the public and the environment.

Table 16: Unplanned Interruptions - historical performance

	FY2018	FY2019	FY2020	FY2021	FY2022
Number of Unplanned Interruptions	2	1	0	0	0
Number of Major Interruptions	0	0	0	0	0

Note: A major interruption means any declaration of a critical contingency caused or contributed to by an incident on the transmission assets owned or controlled by the GTB which results in curtailment directions being issued in respect of any band beyond Band 1.

Historical performance shows that unplanned interruptions are relatively rare.

INTERRUPTION TARGET

Zero interruptions

H.5.4 SECURITY AND RELIABILITY: COMPRESSOR AVAILABILITY

Compressors are critical to the performance of the transmission system. Without them, the system is unable to consistently deliver contractual capacity to consumers. Compressors are expected to have a lower availability compared to pipelines (which are more robust and have no moving parts). It is therefore important to monitor the reliability performance of compressors to ensure the reliability of the system.

Table 17: Compressor availability - historical performance

	FY2018	FY2019	FY2020	FY2021	FY2022
Compressor fleet reliability	96%	97%	88.5%	92.3%	88.6%
Compressor fleet availability	83%	89%	93%	94%	92%

Historical performance has not met the required target levels. As part of the approach to lifting compressor performance a control system replacement programme is underway.

Compressor Availability Target

Maintain compressor fleet reliability (excl. planned outages) > 97%

Maintain compressor fleet availability (incl. planned outages) > 95%

H.5.5 Security and Reliability: Public Reported Escapes and Gas Leaks

Public Reported Escapes (PRE) is commonly used in New Zealand and Australia to measure the integrity of gas transmission system. Escapes are defined as any escapes of gas confirmed by Firstgas excluding third party damage events, routine survey findings and no traces events.

Table 18: PRE - historical performance

	FY2018	FY2019	FY2020	FY2021	FY2022
PRE per 1000km	2	5	3.6	2.38	1.590

Historical performance has met previous target levels on a consistent basis.

PRE Target

<= 5 confirmed public reported escapes per 1000 km per year.

H.5.6 Environmental

The Company's purpose is to provide a safe and reliable gas supply to all customers in a safe and reliable manner that minimises any adverse impact on the environment. Firstgas will comply with all legislative requirements and where possible exceed these. The Policy sets out the commitment to the environment for employees, contractors, communities, visitors, customers and for future generations and will continually improve all aspects of environmental practices.

Table 18: Environmental - historical performance

	FY2018	FY2019	FY2020	FY2021	FY2022
Impact on the environment	0	0	0	0	0

Environmental Target

Full compliance with all requirements from local and regional councils and to have no prosecutions based on breaches, environmental regulations or requirements.

H.5.7 Compliance

A five-yearly certificate of fitness is issued to Firstgas by approved inspection body Lloyds. Lloyds also carry out an annual audit comparing the Company's practices to *AS/NZS2885*. The target is to have zero non-compliances from the audit but in the case where a non-compliance is noted (that may occur occasionally) then a target to resolve the issue within three months.

Table 19: Compliance - historical performance

	FY2018	FY2019	FY2020	FY2021	FY2022
Number of non-compliances	0	2	1	2	2

Lloyds Annual Audit Target
Number of non-compliances audit target: 0
If a non-compliance is noted, then timeframe for rectification plan implementation: three-months

Asset Management Maturity Assessment Tool (AMMAT):

Firstgas has conducted assessments using the Asset Management Maturity Assessment Tool as per the information disclosure requirements in schedule 13, the self-assessment is included in appendix B. Although the Schedule 13 AMMAT is not prescriptive in the use of which standard is used to conduct the self-assessment, it does reference PAS55 standard, which has been superseded by the *ISO55000* suite of standards.

In addition to the self-assessment, Firstgas engaged Assetivity an external *ISO55001* accredited organisation to conduct a gap assessment of asset management practices determining alignment to *ISO55001:2014* asset management standard.

Firstgas intends to use the outcome of this external body evaluation to develop an improvement plan to ensure that it is fully compliant and ultimately achieve accreditation with *ISO55001:2014* International standard.

H.6.1 Assessment Approach

Assetivity applied the IAM self-assessment methodology tool to evaluate Firstgas Group's alignment with the requirements of *ISO55001* and to identify areas for improvement. Staff were interviewed and key documents were reviewed to assess the maturity against the elements of *ISO55001* as follows.

Management System and Context - The assessment checks for an understanding of context and alignment with the business objectives; consistent decision-making criteria and a clear scope for the management system

Leadership – The assessment covers the level of leadership commitment towards asset management and publication and implementation of an Asset Management Policy and strategy. It also assess if roles and responsibilities are clearly defined.

Planning - The assessment covers the existence of plans for its asset portfolio, how these align with the organisation's goals and objectives, and how these plans are developed.

Support elements – The assessment evaluates the capability and capacity of supporting elements including resources, competence, communication, information and documentation.

Operational Control – The processes for managing and controlling operations and maintenance activities are evaluated, as well as the process for managing technical change and for managing outsourced activities.

Performance Evaluation – The systems for monitoring and evaluation performance and conformance with asset management system requirements are assessed.

Improvement – The readiness assessment reviews the organisations processes for dealing with non-conformity, preventative actions and continual improvement of its performance and its asset management systems.

H.6.2 Report Outcome

The table below presents the maturity scale which Firstgas was measured against, a maturity score of 3 is required in all elements to achieve compliance with the standards.

Scale	Description	Definition
0	Innocent	The organisation has not recognised the need for this requirement and/or there is no evidence of commitment to put it in place.
1	Aware	The organisation has identified the need for this requirement, and there is evidence of intent to progress it.
2	Developing	The organisation has identified the means of systematically and consistently achieving the requirement and can demonstrate that these are being progressed with credible and resource plans in place.
3	Competent	The organisation can demonstrate it is systematically and consistently achieves relevant requirements set out in *ISO55001*
4	Optimising	The organisation can demonstrate it is systematically and consistently optimising its asset management practice, in line with the organisation's objectives and operating context.
5	Excellent	The organisation can demonstrate that it employs leading practices and achieves maximum value from the management of its assets, in line with the organisation's objectives and operating context.

The results presented below demonstrates where the Company falls in the range between Developing and Competent.

Rating		AMMAT Score																										
Excellent	5																											
Optimising	4																											
Competent	3			3.00						3.00	3.00	3.00					3.00		3.00	3.00			3.00	3.00	3.50	3.00	3.00	3.00
Developing	2	2.50	2.70		2.71	2.60	2.00	3.00	2.58				2.50	2.36	2.14	2.67		2.33			2.50	2.00						
Aware	1																											
Innocent	0																											
Clause		4.1	4.2	4.3	4.4	5.1	5.2	5.3	6.1	6.2.1	6.2.2	7.1	7.2	7.3	7.4	7.5	7.6.1	7.6.2	7.6.3	8.1	8.2	8.3	9.1	9.2	9.3	10.1	10.2	10.3

Table showing the *ISO55001:2014* Clauses and the Rating assigned by Assetivity

H.6.3 Context of the Organisation

ISO55001 - Sections 4.1, 4.2, 4.3 & 4.4

The AMMAT report indicates that Firstgas are not fully compliant for three of the four sections. The main recommendation is to form an Asset Management (AM) Steering Committee to review the performance of the processes and implement a coordinated performance development process.

H.6.4 Leadership

ISO55001 - Sections 5.1, 5.2 & 5.3

Whilst Firstgas did not fully meet the requirement for a competent rating for two of the three sections, the other areas can be dealt with through the formation of the AM Steering Committee

H.6.5 Planning

ISO55001 - Sections 6.1 & 6.2

Section 6.1 covers the risks and opportunities for improvement that will ensure sufficient processes and practices are in place to support the documentation. Section 6.2 is concerned with AM objectives and planning, where Firstgas is competent but with 'opportunities for improvement' identified.

H.6.6 Support

ISO55001 - Sections 7.1,7.2,7.3,7.4,7.5 & 7.6

Since this section covers a wide range of area across the business it is one of the principal areas that is 'In Development' and therefore requires the most work to bring the Company up to a competent level and therefore the area where the most improvement can be achieved.

H.6.7 Operation

ISO55001 - Sections 8.1, 8.2 & 8.3

Whilst competent with the document control section, it was noted further improvements could be made. These recommendations are in relation to Management of Change and Outsourcing activities.

H.6.8 Performance Evaluation

ISO55001 - Sections 9.1, 9.2 & 9.3

Firstgas are competent with these sections, however there are several 'opportunities for improvement'.

H.6.9 Improvement

ISO55001 - Sections 10.1, 10.2 & 10.3

Firstgas are competent with all sections however there is a recommendation to implement a process for managing non-conformities when the Asset Management System is utilised and to ensure there are systems and processes in place for internal audits and management reviews involved.

H.6.10 Summary

In order to achieve full alignment with *ISO55001:2014*, the report has made 19 recommendations and 23 opportunities for improvements. A road map to achieve full compliance has been developed. The following steps have been recommended:

- Step 1 Improve Internal Stakeholder Communication
- Step 2 Review Asset Management System Performance

- Step 3 Review Asset Management Information capture and management.
- Step 4 Ensure contractor management is holistic.
- Step 5 Ensure competence management accounts for asset management competence
- Step 6 Review stores and inventory management processes and impact on asset management system risk.
- Step 7 Consider a combined business Strategic Asset Management Plan

Over the course of the next 12 to 18 months Firstgas intends to work through the recommendations and improvements to prepare for accreditation to *ISO55001*.

I.1. SYSTEM CAPACITY DETERMINATION

This appendix sets out the forecast demands on the system and describes the capacity determination methodology.

I.2. CAPACITY FORECASTS

North Pipeline Capacity Forecast

DELIVERY POINT		AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
			FY2023	FY2028	FY2033
	Tuakau2	1,939	41,045	40,966	40,887
	Harrisville2	1,580	38,228	38,227	38,228
	Ramarama	-	15,939	15,938	15,937
	Drury 1	1,057	118,02	117,008	115,605
	Pukekohe	-	50,802	50,691	50,587
	Glenbrook	6,809	25,114	25,048	24,983
	Total for Greater Auckland	**45,437**	**65,960**	**64,621**	**63,166**
Greater Auckland	Bruce McLaren	1,477	8,877	8,815	8,754
	Henderson	2,831	13,543	13,266	12,991
	Papakura	9,687	39,853	39,733	39,614
	Waikumete	5,897	26,138	25,558	24,984
	Westfield	25,545	65,960	64,621	63,166
	Hunua (Three DPs)	1,206	109,995	109,480	108,899
	Flat Bush	1,603	97,578	96,830	96,097
	Waitoki	880	22,485	21,907	21,232
	Marsden (Both DPs)	-	17,522	17,176	17,156
	Whangarei	529	10,735	10,688	10,620
	Kauri + Maungaturoto	5,000	1,441	3,131	3,105
	Alfriston	-	13,330	13,327	13,324
	Waiuku	-	14,383	14,343	14,304
	Warkworth 2	1,572	1,552	1,551	1,549

The peak week was the week ending the 26 Jun 2022

Negligible demand was observed at the Wellsford and Kingseat Delivery Points during the North System's peak week. Pipeline capacity was not determined for those sites.

Contractual capacity is allocated to Kauri and Maungaturoto collectively.

Rotowaro compression was modelled running continuously with a constant discharge pressure of 84 barg.

Henderson compression was modelled running continuously with a constant discharge pressure of 84 barg.

Aggregate Contractual Capacity is apportioned to Bruce McLaren, Henderson, Papakura, Waikumete and Westfield in proportion to the operational capacity for these delivery points during FY 2022.

New Zealand Refining was shut down during FY2023 with only a small residual load. Capacity data is based on New Zealand Refining being shut down.

Aggregate Contractual Capacity indicated for major points only.

North Pipeline Delivery Point Capacity Forecast

North Pipeline Delivery Point	Actual	Forecast			Capacity (SCM/hour)	Year of Breach	Equipment	Comments
	2022	2023	2028	2033				
Alfriston	96	133	133	133	336	no breach	Regulators	
Bruce McClaren	2,578	2,571	2,788	3,006	2,430	≤ 2023	Bath Heater	Heater nameplate capacity = 2500 Nm3/h, capacity based on historical data - 2430 SCMH to attain 2 deg C outlet temperature from the DP
Drury 1	1,859	2,466	2,466	2,466	2,700	no breach	Bath Heater	
Flat Bush	2,386	2,480	2,530	2,580	6,590	no breach	Meter	
Glenbrook	10,856	12,210	12,210	12,210	13,213	no breach	Meter	
Harrisville 2	3,569	3,788	3,788	3,788	6,683	no breach	Meter	
Henderson	7,817	10,662	10,662	10,662	17,200	no breach	Bath Heater	
Hunua	766	864	1,127	1,389	2,800	no breach	Bath Heater	
Hunua (Nova)	577	602	602	602	740	no breach	Meter	
Hunua 3	897	956	956	956	3,680	no breach	Meter	
Kauri DF	3,181	3,216	3,216	3,216	3,782	no breach	Regulators	
Kingseat	8	12	12	12	50	no breach	JT cooling limits station capacity, no WBH	
Marsden 2	218	218	218	218	788	no breach	Regulators	
Marsden 1 (Refinery)	10,284	-	-	-	19,360	no breach	Meter	Refinery is shutdown. Station to be downsized to suit current peak flow rates.
Maungaturoto DF	2,503	2,538	2,538	2,538	3,300	no breach	Bath Heater	
Papakura	18,962	19,564	22,476	25,388	30,600	no breach	Meter	
Pukekohe	606	685	685	685	705	no breach	Regulators	
Ramarama	369	376	376	376	380	no breach	Meter	
Tuakau 2	3,600	5,295	5,295	5,295	12,300	no breach	Bath Heater	
Waikumete	9,251	10,206	10,206	10,206	18,720	no breach	Meter	
Waitoki	2,881	3,341	3,341	3,341	3,900	no breach	Bath Heater	
Waiuku	443	560	560	560	1,331	no breach	Regulators	
Warkworth 2	2,525	2,663	2,663	2,663	2,900	no breach	Bath Heater	
Wellsford	-	-	-	-	50	no breach	JT cooling limits station capacity, no WBH	
Westfield	42,848	44,972	46,646	48,321	72,850	no breach	Meter	
Whangarei	1,063	1,063	1,063	1,063	1,393	no breach	Regulators	

BOP Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2023	FY2028	FY2033
Broadlands	-	4,017		
Edgecumbe (Both DPs)	4,189	4,088	4,040	4,015
Gisborne	1,296	4,375	4,374	4,372
Mount Maunganui	2,529	1,739	1,577	1,415
Tauranga (Includes Pyes Pa)	1,495	1,413	1,478	1,401
Kawerau (Three DPs)	2,414	12,100	11,896	11,806
Kihikihi	-	139,230	124,155	106,752
Kinleith (Both DPs)	10,000	52,949	51,726	48,688
Lichfield (Both DPs)	5,750	21,410	21,213	21,212
Opotiki	-	5,363	5,354	5,346
Putaruru	-	25,095	21,927	18,378
Rangiuru	-	1,458	1,458	1,269
Reporoa	1,928	8,663	5,540	5,541
Rotorua	1,692	2,869	2,853	2,847
Taupo	-	6,151		
Tauriko	-	6,167	5,650	5,125
Te Puke	-	1,877	1,576	1,263
Tirau (Both DPs)	1,450	10,022	9,948	9,630
Tokoroa	-	39,830	37,906	32,180
Waikeria	-	107,795	95,023	81,188
Whakatane	3,679	2,158	2,121	2,102

The peak week for this system was the week ending 25/09/2022.

Negligible demand was observed at Okoroire and Te Teko Delivery Points during the peak week. Pipeline capacity was not determined for those sites.

Pokuru compression was modelled running continuously with a constant discharge pressure of 74 barg.

Kawerau compression was modelled running continuously with a constant discharge pressure of 84 barg.

The Rangiuru lateral is operated as a distribution IP main. The minimum acceptable pressure at the inlet to the Rangiuru Delivery Point has been taken as 10 barg. Although not defined in the Gas Transmission Security Standard, 10 barg is the minimum accepted pressure for distribution.

The estimated demand at a new Delivery Point that has come online at Tauriko during 2023 has been included at 3,300 GJ/day.

A large-scale biogas project is now underway at Broadlands. This is expected to inject the biogas into Reporoa to Taupo pipeline to supplement gas supply from FY23 onwards. To facilitate this project, it is proposed to operate the Reporoa to Taupo pipeline at less than 20 bar g. Normal transmission operating pressure wouldn't be restored unless the demand for capacity on this section of the pipeline requires it. Therefore, transmission capacity modelling for the Broadlands and Taupo Delivery Points will be discontinued from FY23 onwards.

Aggregate Contractual Capacity indicated for major points only.

BOP Pipeline Delivery Point Capacity Forecast

BOP Pipeline Delivery Point	Actual	Forecast			Capacity (SCM/hour)	Year of Breach	Equipment	Comments
	2022	2023	2028	2033				
Broadlands	634	661	661	661	739	no breach	Regulators	
Edgecumbe	27	27	27	27	230	no breach	Meter	
Edgecumbe DF	5,109	6,124	6,124	6,124	6,200	no breach	Bath Heater	
Gisborne	2,732	3,144	3,144	3,144	5,500	no breach	Bath Heater	
Kawerau (Tissue)	830	869	869	869	2,423	no breach	Regulators	
Kawerau (Pulp & Paper)	2,173	2,235	2,235	2,235	4,846	no breach	Regulators	
Kawerau	95	122	122	122	325	no breach	Regulators	
Kihikihi	600	880	880	880	2,090	no breach	Meter	
Kinleith (Pulp & Paper)	26,502	30,611	30,611	30,611	30,355	minor breach	Regulators	No growth
Kinleith SS - shared equipment	26,596	30,715	30,715	30,715	38,800	no breach	Bath Heater	
Lichfield DF	2,820	2,897	2,897	2,897	4,970	no breach	Meter	
Lichfield 2	4,380	4,587	4,587	4,587	8,120	no breach	Meter	
Mt Maunganui	3,224	3,431	3,431	3,431	4,680	no breach	Meter	
Okoroire Springs	-	-	-	-	50	no breach	JT cooling limits station capacity, no WBH	
Opotiki	217	217	217	217	850	no breach	Meter	
Papamoa	634	634	634	634	4,050	no breach	Meter	
Papamoa 2	437	661	661	661	4,050	no breach	Meter	
Putaruru	154	481	481	481	780	no breach	Bath Heater	
Pyes Pa	1,272	1,272	1,272	1,272	1,790	no breach	Meter	
Rangiuru	610	588	662	736	1,104	no breach	Regulators	
Reporoa	2,652	2,652	2,652	2,652	3,221	no breach	Filter	
Rotorua	3,093	3,525	3,525	3,525	5,600	no breach	Bath Heater	
Taupo	1,258	1,353	1,353	1,353	4,340	no breach	Meter	
Tauranga	1,815	2,167	2,167	2,167	2,580	no breach	Meter	
Tauriko	-	4,150	4,150	4,150	7,960	no breach	Meter	New Station, no historical data
Te Puke - 2nd Cut to DRS	667	667	667	667	900	no breach	Meter	
Te Teko	-	-	-	-	147	no breach	Regulators	
Tirau	57	60	60	60	600	no breach	Meter	
Tirau DF	2,092	2,314	2,314	2,314	4,000	no breach	Bath Heater	
Tokoroa	1,622	1,622	1,622	1,622	2,590	no breach	Meter	
Waikeria	113	184	675	675	738	no breach	Regulators	Forecast increase due to Corrections Dept. prison expansion
Whakatane	3,915	4,333	4,333	4,333	5,800	no breach	Bath Heater	

Central North Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2023	FY2028	FY2033
Cambridge	2,046	1,467	2,155	2,152
Greater Hamilton	7,290	21,825	33,977	33,367
Horotiu		12,705	20,851	20,294
Kiwitahi	1,000	3,864	5,593	5,381
Morrinsville	950	3,040	4,259	4,133
Tatuanui	1,500	3,392	4,814	4,755
Te Rapa DF	FY2023: 23,200 FY2024 - FY2033: 11,232	14,490	25,670	24,853
Waitoa	1,723	3,447	4,875	4,779

The peak week was the week ending 14 August 2022.

Compression at Rotowaro was modelled running continuously with a constant discharge pressure of 84 barg.

Te Rapa Cogen was shut down in June 2023 however, dairy factory remains. Now referred to as Te Rapa Dairy Factory.

Aggregate Contractual Capacity indicated for major points only.

Central North Pipeline Delivery Point Capacity Forecast

Central North Delivery Point	Actual	Forecast			Capacity (SCM/hour)	Year of Breach	Equipment	Comments
	2022	2023	2028	2033				
Te Rapa Cogen	23,430	15,864	11,700	11,700	27,300	no breach	Bath Heater	Te Rapa Cogen shutting down during 2023. DF load only
Hamilton Temple View	7,898	10,107	10,107	10,107	10,800	no breach	Meter	
Cambridge	3,122	3,148	3,148	3,148	4,310	no breach	Meter	
Hamilton Te Kowhai	5,136	5,722	5,722	5,722	10,780	no breach	Meter	
Waitoa	2,142	2,142	2,142	2,142	3,761	no breach	Filter	
Kiwitahi 1 (Peroxide)	1,154	1,185	1,185	1,185	3,300	no breach	Bath Heater	
Kiwitahi 2	211	211	211	211	3,300	no breach	Bath Heater	
Tatuanui DF	2,063	2,063	2,063	2,063	3,400	no breach	Bath Heater	
Morrinsville SS - shared equipment	2,005	2,239	2,239	2,239	3,800	no breach	Bath Heater	
Morrinsville DF	1,782	1,906	1,906	1,906	4,110	no breach	Meter	
Horotiu	2,149	2,149	2,149	2,149	4,310	no breach	Meter	
Morrinsville	450	456	456	456	1,440	no breach	Meter	
Matangi	17	18	18	18	50	no breach	JT cooling limits station capacity, no WBH	

Central South Pipeline Capacity Forecast

CENTRAL SOUTH DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2023	FY2028	FY2033
Eltham		9,729	9,729	9,729
Inglewood		7,878	7,877	7,877
Kaponga		2,835	2,835	2,835
New Plymouth	3,013	4,895	4,886	4,878
Stratford		79,057	78,517	78,470
Waitara		7,332	7,347	7,347

The peak week was the week ending 30 January 2022.

Pokuru offtake was set to zero during modelling.

Compression at Mahoenui was not running during modelling.

Compression at Kapuni was modelled running continuously with a constant discharge pressure of 84 barg.

Aggregate Contractual Capacity indicated for major points only.

Central South Pipeline Delivery Point Capacity Forecast

Central South Delivery Point	Actual	Forecast						
	2022	2023	2028	2033	Capacity (SCM/hour)	Year of Breach	Equipment	Comments
New Plymouth	6,916	6,816	7,366	7,916	7,800	2031	Bath Heater	Long ways out, probably no growth
Eltham	963	1,126	1,126	1,126	1,456	no breach	Regulators	
Waitara	723	864	864	864	1,130	no breach	Regulators	
Stratford	671	722	722	722	891	no breach	Regulators	
Inglewood	348	410	410	410	384	≤ 2023	Regulators	Minor breach. No Growth. One off peak 5 years in the past, but trending downwards.
Kaponga	18	17	18	19	140	no breach	Regulators	

South Pipeline System Capacity Forecast

SOUTH DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2023	FY2028	FY2033
Ashhurst	0	4,298	6,156	7,326
Belmont	6,310	2,916	4,310	4,922
Dannevirke	0	4,287	6,098	7,206
Feilding	835	3,067	3,909	4,396
Foxton	0	4,740	7,283	8,775
Hastings (Both DPs)	7,294	3,191	4,685	5,545
Hawera (Both DPs)	1,217	31,286	34,901	37,496
Kaitoke	0	2,998	3,003	3,005
Kakariki	0	3,605	4,141	4,525
Greater Kapati	859	3,733	11,048	13,096
Lake Alice	0	3,422	4,014	4,366
Levin	1,134	3,614	5,442	5,835
Longburn	801	3,349	4,330	4,877
Manaia	0	4,615	4,632	4,610
Mangaroa	0	3,958	5,681	6,694
Marton	743	5,486	6,069	6,621
Otaki	0	4,134	6,358	7,679
Pahiatua (Both DPs)	3,000	1,787	3,631	4,051
Palmerston North	3,805	2,133	2,866	3,249
Patea	0	29,557	31,709	34,754
Takapau	0	4,302	6,062	7,148
Tawa (Both DPs)	11,180	2,437	4,136	5,082
Greater Waitangirua	1,910	3,308	5,279	6,487
Waitotara	0	24,471	27,320	30,006
Whanganui	4,407	24,521	25,175	27,455
Waverley	0	893	894	895

The South System's Peak week was the week ending 14 August 2022.

The calculation of Uncommitted Operational Capacity at Tawa is based on the minimum acceptable pressure at the inlet to both Tawa A and B being 10 barg. Although not defined in the Gas Transmission Security Standard, 10 barg is the minimum accepted pressure for distribution.

Kapuni compression was modelled running continuously with a constant discharge pressure of 84 barg

Kaitoke compression was modelled running continuously with a discharge set pressure of 84 barg

600 looping line regulated to 64.5 barg between Hawera Delivery Point and Kaitoke Compression.

Aggregate Contractual Capacity indicated for major points only.

South Pipeline Delivery Point Capacity Forecast

South Pipeline Delivery Point	Actual	Forecast			Capacity (SCM/hour)	Year of Breach	Equipment	Comment
	2022	2023	2028	2033				
Ashhurst	100	100	100	100	137	no breach	Bath Heater	
Belmont	12,478	14,212	14,212	14,212	15,000	no breach	Bath Heater	A peak flow of 17,305 SCMH was observed during 2021, however, this appears to be a rare anomaly.
Dannevirke	479	521	521	521	480	≤ 2023	Regulators	Used forced flatline. Low growth suspected and probably dominated by local industrial load which seems to increase in flat step increases. Monitor reg outlet pressure for signs of hitting maximum flow.
Feilding	1,519	1,827	1,827	1,827	3,600	no breach	Bath Heater	
Flockhouse	-	-	-	-	50	no breach	JT cooling limits station capacity, no WBH	
Foxton	334	314	333	352	554	no breach	Regulators	
Hastings	11,831	12,698	13,758	14,819	17,320	no breach	Meter	
Hastings (Nova)	1,086	1,579	1,579	1,579	4,450	no breach	Meter	
Hawera	2,613	2,827	2,827	2,827	6,200	no breach	Bath Heater	
Hawera (Nova)	488	591	591	591	990	no breach	Meter	
Kairanga	296	335	335	335	50	≤ 2023	JT cooling limits station capacity, no WBH	Made RIR 13228 for this.
Kaitoke	147	162	162	162	166	no breach	Bath Heater	
Kakariki	509	507	510	513	710	no breach	Meter	
Kuku	-	-	-	-	50	no breach	JT cooling limits station capacity, no WBH	
Lake Alice	301	308	308	308	318	no breach	Regulators	Using forced flatline. Rural area, low growth just jumped up a few
								years ago probably due to changes to local grain dryer equipment.
Levin	1,760	2,259	2,259	2,259	2,597	no breach	Meter	
Longburn	1,368	1,481	1,758	2,035	2,700	no breach	Regulators	
Mangaroa	134	152	152	152	180	no breach	Meter	
Mangatainoka	-	36	-	-	678	no breach	Regulators	Expected to be shut down by 2025
Marton	1,156	1,329	1,329	1,329	2,800	no breach	Bath Heater	
Matapu	-	-	-	-	50	no breach	JT cooling limits station capacity, no WBH	
Manaia	166	154	165	175	219	no breach	Regulators	
Oroua Downs	253	266	266	266	330	no breach	Meter	Using forced flatline. Rural area, low growth just jumped up a few years ago probably due to changes to local grain dryer equipment.
Otaki	211	241	241	241	652	no breach	Regulators	
Pahiatua DF	3,948	4,144	4,144	4,144	4,605	no breach	Meter	
Pahiatua	78	97	101	106	610	no breach	Meter	
Palmerston North	7,318	8,475	8,475	8,475	8,502	no breach	Regulators	
Paraparaumu	1,034	1,154	1,154	1,154	1,560	no breach	Pipework	
Patea	213	241	241	241	300	no breach	Bath Heater	
Pauatahanu 1	1,076	1,156	1,302	1,447	2,593	no breach	Regulators	
Pauatahanu 2	5	-	-	-	50	no breach	JT cooling limits station capacity, no WBH	
Takapau	605	696	696	696	827	no breach	Regulators	
Tawa B	2,267	2,700	2,700	2,700	5,490	no breach	Pipework	
Te Horo	-	-	-	-	50	no breach	JT cooling limits station capacity, no WBH	

South Pipeline Delivery Point	Actual	Forecast			Capacity (SCM/hour)	Year of Breach	Equipment	Comment
	2022	2023	2028	2033				
Waikanae 2	1,136	1,251	1,251	1,251	2,647	no breach	Regulators	
Waitangirua (Wellington) / Tawa A	21,496	22,598	22,598	22,598	27,000	no breach	Bath Heater	
Waitangirua (Porirua)	3,336	3,348	3,379	3,410	4,550	no breach	Meter	
Waitotara	253	267	267	267	325	no breach	Regulators	
Whanganui	5,876	6,880	6,493	6,493	7,400	no breach	Bath Heater	
Waverley	5	5	5	5	50	no breach	JT cooling limits station capacity, no WBH	

Frankley Road Pipeline Capacity Forecast

FRANKLEY ROAD DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2023	FY2028	FY2033
Ammonia-Urea Plant	22,500	3,647	7,681	7,681
Kaimiro DP	0	15,506	17,928	17,928
Kapuni (Lactose	0	9,016	11,238	11,238
Kapuni GTP	25,000	42,771	48,330	48,330
TCC + Stratford 2 + Stratford 3	FY 2023:179,000 FY 2028 & FY 2033:115,000	22,565	44,769	44,769

The peak week was the week ending 17 July 2022.

While there are major sources of gas near the centre of the pipeline (Ahuroa) and at its southern end (Kupe), Ahuroa is not a continuous source while Kupe has an annual shutdown. Nor can either of these sources supply total demand on the pipeline. Modelling was therefore based on all gas entering the pipeline at Frankley Road, at a constant pressure of 44 barg, since that is more informative in relation to pipeline capacity.

TCC refers to the DP for the Taranaki combined-cycle power station, Stratford 2 is the DP for the Stratford peaker power station and Stratford 3 is the DP for the Ahuroa underground storage facility.

The Taranaki Combined Cycle power station is anticipated to be closed by 2025.

Frankley Road Pipeline Delivery Point Capacity Forecast

Frankley Road Pipeline Delivery Point	Actual	Forecast						
	2022	2023	2028	2033	Capacity (SCM/hour)	Year of Breach	Equipment	Comment.
TCC	69,456	71,000	-	-	#N/A	no breach	#N/A	Expected to be shut down by 2025
Stratford 2	46,160	62,500	62,500	62,500	#N/A	no breach	#N/A	
Stratford 3 Delivery	74,440	74,796	74,796	74,796	#N/A	#N/A	#N/A	
Ammonia Urea (Fuel)	10,160	10,397	10,397	10,397	15,657	no breach	Regulators	
Ammonia Urea (Process)	12,436	12,800	12,800	12,800	15,657	no breach	Regulators	
Kapuni (Lactose)	204	214	214	214	353	no breach	Regulators	

Maui System Pipeline Capacity Forecast

MAUI DELIVERY POINT	PEAK DEMAND (GJ/DAY)	OPERATIONAL CAPACITY (GJ/DAY)		
		FY2023	FY2028	FY2033
Huntly Town	33	73,838	73,812	73,822
Pirongia (Three DPs)	1,909	155,727	155,620	155,501
Otorohanga	27	142,146	133,076	121,561
Ngaruawahia	13	103,910	118,487	127,341
Te Kuiti North	116	4,048	4,033	4,013
Te Kuiti South	668	8,446	8,422	8,387
Oakura	32	6,697	6,674	6,646
Mangorei	3,616	88,560	81,989	60,998
Rotowaro	76,922	153,188	146,179	141,387
Pokuru	36,181	172,347	165,521	156,305
Bertrand Road	46,154	182,755	168,146	152,013
Huntly Power Station	59,439	155,223	143,004	128,769

The peak week for this system was the week ending 10 October 2021.

On the Maui System, each Shipper's capacity for a day is its approved nominated quantity for that day, i.e., Shippers do not have rights to firm capacity. Therefore, "Aggregate Contractual Capacity" does not apply on the Maui System as it does on other pipeline systems.

The table instead shows:

- "Peak Demand", i.e., the GJ taken on the first day of the system peak period at each Delivery Point, and
- "Operational Capacity" (i.e., the aggregate pipeline capacity available to each Delivery Point during the system peak period).
- Maui pipeline assumed running at a constant pressure of 46 barg at the Oaonui Production Station end.
- Mokau compression was modelled running continuously with a constant discharge pressure of 61 barg.

Maui Pipeline Delivery Point Capacity Forecast

Maui Pipeline Delivery Point	Actual	Forecast						
	2022	2023	2028	2033	Capacity (SCM/hour)	Year of Breach	Equipment	Comments
Huntly Town	313	334	334	334	840	no breach	Regulators	
Pirongia	22	26	26	26	50	no breach	JT cooling limits station capacity, no WBH	
Te Awamutu North	243	505	505	505	860	no breach	Meter	
Te Awamutu DF	4,083	4,481	4,481	4,481	7,500	no breach	Meter	
Otorohanga	141	150	150	150	220	no breach	Meter	Otorohanga Delivery Point was expected to be upgraded to accommodate a new industrial load commencing mid-2022, however the project has been indefinitely delayed.
Ngaruawahia	66	80	80	80	129	no breach	Regulators	
Te Kuiti North	266	288	288	288	938	no breach	Regulators	
Te Kuiti South	953	1,011	1,011	1,011	1,909	no breach	Regulators	
Te Kuiti South Delivery Point - 2nd Cut to DRS	200	200	200	200	811	no breach	Regulators	
Oakura	155	160	191	223	232	no breach	Meter	Meter @ 100%
Bertrand Road	7,366	61,920	61,920	61,920	#N/A	#N/A	#N/A	This is an offtake pipe to Methanex Waitara Valley. Capacity only restrained by pipe size, flat industrial load and no growth. Does not need to be included in the AMP for Capacity
Ngatimaru Road	145,592	154,822	162,825	170,829	#N/A	#N/A	#N/A	Pohokura Gas Tie In (receipt point) Does not need to be included in the AMP for Capacity
Huntly PowerStation	192,306	181,404	202,533	223,661	269,946	no breach	Filter	
Mangorei	25,764	25,886	25,886	25,886	71,969	no breach	Filter	
Opunake	94	102	102	102	241	no breach	Regulators	
Okato	39	55	62	69	133	no breach	Regulators	
Pungarehu No. 1	-	1	1	1	50	no breach	JT cooling limits station capacity, no WBH	
Pungarehu No. 2	13	15	15	15	50	no breach	JT cooling limits station capacity, no WBH	

I.3. Sources of Data for Pipeline and Delivery Point Modelling

Metered data from OATIS is used for both Pipeline and Delivery Point demand modelling analysis. Data is extracted over many years to identify growth trends for Delivery Points. For Pipelines, hourly metered data profiles are extracted from OATIS and loaded directly into Synergi Software.

Delivery Point equipment capacity is either extracted from manufacturers' data or calculated from performance and asset information located in our asset management systems.

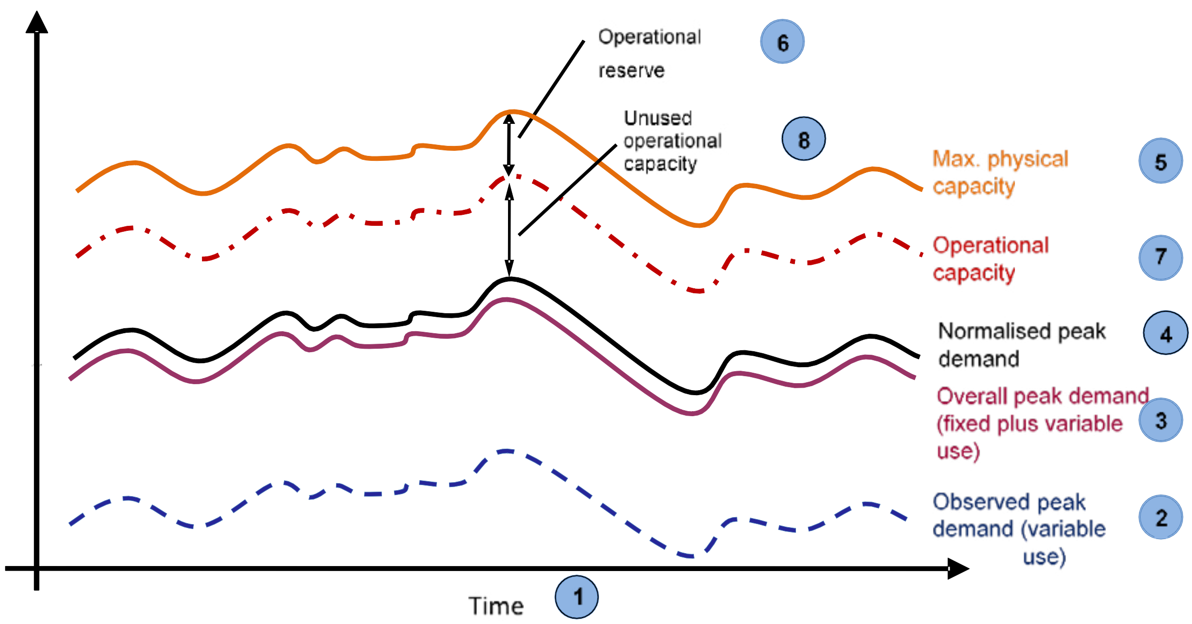
Pipeline data is taken from asset management systems and GIS.

I.4. Pipeline Capacity Forecasting Methodology

The approach to determining the physical capacity of Firstgas pipeline systems is based on several factors. The steps followed, and the assumptions made are described below. To aid in this description, reference is made to the following diagram.

For modelling analysis Synergi software is used, which is a leading, internationally recognised product, produced by DNV GL.

Figure A9: Overview Schematic for pipeline capacity determination



The steps to determine pipeline capacity are as follows:

- Select the time period that reveals the pipeline's peak demand cyclical performance from pressure depletion to pressure recovery
- Obtain actual demand profiles for variable demands during the selected time period.
- Determine "fixed" demands
- Normalise the variable demand profiles to reflect the long-term trend
- Run the model to determine the maximum physical demand that can be sustained without breaching the System Security Standard

- Allow for an "operational reserve" to cover severe winter demands as well as an appropriate "survival time" for the pipeline. This establishes the available "operational capacity"
    - Deduct existing normalised peak demand at a delivery point from the operational capacity to determine the unused operational capacity at that delivery point.

Step 1 - Time

The peak demand period relevant to the determination of physical pipeline capacity should be the period of greatest demand from the pipeline where pipeline pressures: (a) do not fall below the minimum acceptable level at any point; and (b) following any depletion, recover to at least their starting levels.[1] For most pipelines the peak demand period is usually a sequence of high demand days (which may or may not include the peak demand day).

Peak demand on the pipelines occurs during the working week. Overall demand on most pipelines (although not necessarily at all delivery points) is invariably lower on weekends. For this reason, modelling is generally based on the 5 days (Monday-Friday, inclusive) in which the highest aggregate demand occurs (the "five-day peak[2]").

At the start of the 5-day peak pressures are generally at their highest. Through the period, should more gas be drawn from the pipeline than can be replenished on a day, pressures in the pipeline will fall[3]. To determine the pipeline's sustainable capacity, pressures must fully recover.

It is noted that in many international gas regimes, peak demand profiles are considered over a 24-hour period only, and gas consumption is limited to ensure that pressures fully recover within this period. This method has been evaluated, but as it would materially reduce the transmission capacity that could be allocated and, given that the system can still be operated within prudent operating levels, it was decided to maintain the five-day peak approach. The system security standard reflects this operating approach.

Step 2 - Observed (Variable) Peak Demand

The second step in a physical capacity determination is to assemble gas demand profiles[4] by observing actual variable demand patterns during the five-day peak (or, potentially, other peak demand period) for all delivery points on the pipeline. Generation loads are excluded at this point as they are assumed to be fixed.

This effectively captures the actual diversity in the demands from the pipeline including, in the case of delivery points supplying distribution networks, the diversity exhibited by often large populations of individual gas consumers. The benefit of this approach is that, for the purpose

[1] Indicating that a further such peak demand period would be sustainable.

[2] The Saturday and Sunday immediately following are also modelled in order to check that pressures recover sufficiently before the start of the next week. Hence any reference in this paper to modelling the 5-day peak should be understood to mean that the relevant 7 days are considered.

[3] Meaning that, while the pressure at different points in the pipeline will cycle up and down within a day, the minimum and maximum levels reached may trend lower from day to day. This may occur for a number of reasons, including operational reasons, coincident peak demand being higher than anticipated or shippers exceeding their capacity entitlements. Where there is compression at the inlet to a pipeline, Firstgas generally operates it in a constant pressure mode (maintaining inlet pressure at relatively constant level).

[4] The Model uses hourly gas flow rates at each delivery point. In this context therefore, "demand profiles" refers to hourly demand quantities for the days comprising the 5-day peak (or other peak demand period). Collectively, such hourly demands are also referred to as the "flow profile" for the relevant delivery point.

of determining the available physical capacity of a pipeline, forecasting this diversity is not required.[5] The implicit assumption being that this is the best predictor of diversity to apply when modelling usage at a level that hits the maximum physical limits of the system. Accordingly, the physical capacity determination is based on the most recent observed five-day peak, as this best reflects the latest demand profile on a pipeline.

This approach does mean, however, that should capacity be allocated equivalent to a pipeline's maximum physical capacity then, if all shippers simultaneously consumed their full contractual gas capacity, this could exceed the pipeline's physical capacity leading to a critical contingency event.[6]

Future demand profiles may differ from those previously observed, which in severe cases could also cause the pipeline's physical capacity to be exceeded.

When modelling to determine pipeline capacity, all contractually interruptible load on a pipeline is set to zero.

Dairy factories' peak demand periods do not generally coincide with the five-day peak of the pipelines from which they are supplied. They are modelled as variable loads, which is generally when they are in their off-peak periods. Other large directly connected customers (excluding power stations) are modelled as variable loads according to their actual demand during the five-day peak, unless their demand in that period was so unusually low as to justify an adjustment factor being applied to simulate more typical operation.

Step 3 - Overall Modelled Peak Demand

To determine the overall demand on a pipeline, fixed loads (if any) need to be added into the model.

Currently, only power stations are treated as fixed loads. While their demand is not literally fixed, when power stations are operating at maximum generating capacity, they represent both near-constant and very substantial loads on the relevant pipeline. Power stations can operate at full capacity at any time of the year. Even if they were not actually operating at peak load during the five-day peak, they might in the future. Accordingly, each power station's demand is modelled as its maximum contractual entitlement rather than its actual demand in the five-day peak.

Step 4 - Normalised Peak Demand

The 4th step in the capacity determination process is to "normalise" five-day peaks to the relevant long-term trend where appropriate.

While actual demand peaks may vary materially from year to year, long-term trends can be discerned for some delivery points. On most of the pipelines[7] this annual variance correlates closely with winter weather patterns, predominantly delivery points to distribution networks which supply large numbers of smaller consumers (amongst others).

A capacity allocation requires an understanding of the underlying demand growth trend. To determine this trend, it is necessary to normalise out annual demand fluctuations that are

5 The counterfactual is that, if we used gas demand profiles representing the peak demand of each individual delivery point on the pipeline, it would need to apply "artificial" diversity factors.

6 As discussed in the System Security Standard.

7 The Bay of Plenty pipeline does not display a strong overall winter peak.

caused by unpredictable external events (such as unexpected temperature levels). This normalisation is done by adjusting the relevant observed five-day peak profile to the average trend in five-day peak values observed over time. Such an adjustment can be both upwards (in a milder-than-average year, where peak consumption was lower than the long-term trend), or downwards (in a colder-than-average year, where peak consumption was higher than the long-term trend). The adjustment is applied to the five-day peak demand profile by means of a single multiplication factor: in other words, the shape of the consumption profile remains as observed, but the actual hourly consumption levels are moved up or down as determined by the normalising factor.

If relevant, where the five-day peak is not predominantly weather-driven, other adjustment factors are applied.

Step 5 - Maximum Physical System Capacity

The 5th step is to determine the maximum physical capacity that a pipeline system can deliver, based on the most recent five-day peak demand profiles (normalised where appropriate) and including fixed loads.

Prudent pipeline operation requires that under all reasonably anticipated consumption and operating conditions the design capacity of pipeline components is not exceeded, and the system security standard is complied with.

Modelling to determine the maximum physical capacity of a pipeline system necessitates simulating increased demand. This involves applying one or more of the following three methods at a delivery point to a pipeline, or more than one delivery point in certain cases:

- Applying a factor to the (normalised) five-day peak.
- Adding a constant flow rate to the (normalised) five-day peak.
- Configuring a separate flow profile that adds to the (normalised) five-day peak.
-

The method(s) used depends on the scenario being modelled, the information available and whether the modelling is being undertaken to provide an indication of the general level of unused physical capacity on the pipeline, or in response to a specific request from a shipper.

Method 1 is the most commonly used. The factor is increased to the point immediately before the system security standard would be breached, which is usually when an unacceptably low minimum pressure occurs at a delivery point on the pipeline.

Method 2 is used to simulate fixed demand.[8] The fixed flow rate is increased until the maximum flow rate short of breaching the system security standard is found.

Method 3 is used to simulate a different flow profile from the observed five-day peak. Having determined the “base” profile, an increasing factor is applied to it until the point immediately before the system security standard would be breached.

When modelling “organic growth”, generally a relatively small percentage increase in demand is expected to follow the existing flow profile, and thus method 1 is used.

[8] It is also used with flow rate set at the estimated MHQ (maximum hourly quantity) as a conservative first test of a pipeline’s ability to support a prospective new load. That is not to imply such an amount of contractual capacity would be allocated.

Method 1 can also be used to give an indication of spare capacity where that is very large (in other words, where the factor is a large number, 5, 10 or 20.) It would need to be borne in mind, however, that if such a large new load were to materialise, it might well exhibit a flow profile materially different from the existing one, which might change the factor.

Method 2 is often used as a first, conservative go/no-go test of a pipeline's ability to supply a new load. For example, a prospective new load might be set at a constant flow rate, set at the rate of its maximum hourly quantity (MHQ). If the pipeline can sustain that, then there is most likely no need for more refined or realistic modelling.

Method 3 can be used where the flow profile of a new load is known and is materially different from the profile of the existing load. Another use might be to test additional load complying with contractual criteria of MHQ and maximum daily quantity ("MDQ"), on a continuous basis, to be sure of the amount of additional contractual capacity that could be allocated at the delivery point.

Step 6 and 7- Operational Capacity and Operational Reserve

Prudent operation of a gas transmission pipeline system requires that it is not operated at a level exceeding its maximum physical capacity. As a reasonable and prudent operator, we must operate the pipeline at "safe" levels, including ensuring that the system security standard is not breached in a manner other than as a result of events beyond the Company's reasonable control.

The "safe" level of physical capacity is termed the "operational capacity" of a pipeline system. It is determined by reducing the maximum physical capacity by an amount known as the "operational reserve". In practice the operational reserve is necessary to allow for two main factors:

- Winter severity: as noted above, winter ambient temperatures are a key determinant of overall peak gas demand on most of our pipelines[9]. We have adopted a one-in-20-year winter incidence (i.e. severity) level to ensure that transmission capacity shortfalls do not occur at an unacceptably high frequency. While this is the current standard, and is a common standard in many other jurisdictions, future economic testing may identify a requirement to revise this.
- Survival time: compression is a key to increasing capacity on most pipeline systems. Our compressor stations are designed with N-1[10] redundancy (as set out in the system security standard). However, a redundant compressor may also fail, or fail to start,[11] and additional time therefore needs to be allowed during which such a failure may be remedied - the so-called survival time. This margin is determined based on the likely time it would take a technician to attend a site, fault-find and manually start a compressor. Again, future economic testing may identify a need to amend this.

The practical effect of the operational reserve is to reduce the total quantity of transmission capacity available that may be allocated as contractual capacity at delivery points on a

[9] The exception, the Bay of Plenty pipeline, has in recent years experienced early summer peaks, which appear to correlate with the gas demand of dairy factories.

[10] An N-1 redundancy level means that a failure on any single component will not affect the ability of the system to deliver its required output.

[11] The availability of compressors, which are complex mechanical units, while still high, is an order of magnitude lower than that of most other components of the transmission system. Compressor failures therefore can occur at a relatively high frequency.

pipeline. The amount of such reduction is different for each pipeline and must be determined for each pipeline individually. This also applies to any pipeline where the five-day peak is not determined by winter conditions.

Step 8 - Unused Operational Capacity

The amount of the operational capacity that shippers are not currently using represents additional gas that could have been conveyed through the pipeline system to delivery points during the five-day peak without reasonably being expected to result in a breach of the System Security Standard, even in the event of a one-in-20-year winter occurring.

Unused operational capacity for a delivery point is calculated simply by subtracting the normalised peak demand from the operational capacity. As noted above, the amount of such capacity is directly affected by the assumptions made about the additional load at the delivery points during modelling.

It is necessary to distinguish “unused” operational capacity from “uncommitted” operational capacity.

I.5. DELIVERY POINT CAPACITY FORECASTING METHODOLOGY

Delivery Point Capacity

The Delivery Point must be able to meet the peak hourly volume. The component(s) that limit the design capacity are identified to allow evaluation of the Delivery Point limitations. When needed, upgrades are be planned to occur prior to the year when the capacity limitation is expected to be exceeded.

The maximum design capacity is calculated using manufacturer data and operating conditions. This information is retained and kept current in a controlled database.

The delivery point database contains calculated maximum design capacity levels of heaters, meters, regulators, filters and station pipework.

Delivery Point Demand Modelling

Load data is collected at all the transmission Delivery Points. The past five earlier years of actual Delivery Point peak hourly volume data is used to develop future demand projections based on straight line trends. Where the forecast indicates a decreasing demand, the highest demand for the past 5 years is used.

Some exceptions to the above are when step changes to demand are known:

- When future demand is expected to be increased or decreased based on the addition or removal of a customer.
- When a customer has been removed and the trend must be adjusted.

The demand for each Delivery point is forecast for the 10-year period following the last year the data was collected.

J.1. EXPENDITURE OVERVIEW

This chapter sets out a summary of expenditure forecasts over the planning period. It is structured to align with expenditure categories and with information provided in Appendices.

The forecasts presented here provide a consolidated view of expenditure across the business. It provides high-level commentary and context on planned investments during the planning period including key assumptions used in developing the forecasts.

Each section includes cross references to an appendix with more information. To avoid duplication, discussions in previous chapters or in the summary document have not been restated.

Note on Expenditure Charts and Tables

The charts in this chapter depict budgeted expenditure for FY2024 (2023/2024) and forecasts for the remainder of the period.

Expenditure is presented according to internal categories. It is also provided in Information Disclosure categories in Schedules 11a and 11b, in Appendix B.

All expenditure figures are denominated in constant value terms using FY2023 New Zealand dollars.

J.2. Inputs and Assumptions

This section describes the inputs and assumptions used to forecast Capex and Opex over the planning period.

J.2.1. Forecasting Inputs and Assumptions

The forecasts rely on several inputs and assumptions. These include:

- Escalation to nominal dollars
- Capital contributions
- Finance during construction

Escalation

Forecasts in this chapter are in constant value terms. In preparing Schedules 11a and 11b real forecasts have been escalated to produce nominal forecasts for Information Disclosure.

While Firstgas expects to face a range of input price pressures over the planning period the escalation approach has been based on the consumer price index (CPI) to align forecast inflation with the initial ‘exposure’ financial model for the gas DPP. Therefore, for the purposes of this AMP assumes changes are limited to CPI rather than adopting more specific indices or modelling trends in network components or commodity indices. Similarly, Firstgas have not sought to reflect trends in the labour market.

For Year Ended	CPI
FY2023	6.20%
FY2024	2.70%
FY2025	2.10%
FY2026	2.00%
FY2027	2.00%
FY2028	2.00%
FY2029	2.00%
FY2030	2.00%
FY2031	2.00%
FY2032	2.00%
FY2033	2.00%

Capital Contributions

Asset relocations expenditure included in the body of the AMP are gross amounts i.e. capital contributions have not been netted out from the forecast. Details of expected capital contributions can be found in Schedule 11a in Appendix B.

Finance During Construction (FDC)

Capex forecasts exclude FDC and have included a forecast of FDC based on expected commissioning dates in Schedule 11a in Appendix B.

J.3. Expenditure Summary

This section summarises the Company's total Capex and Opex forecasts for the planning period.

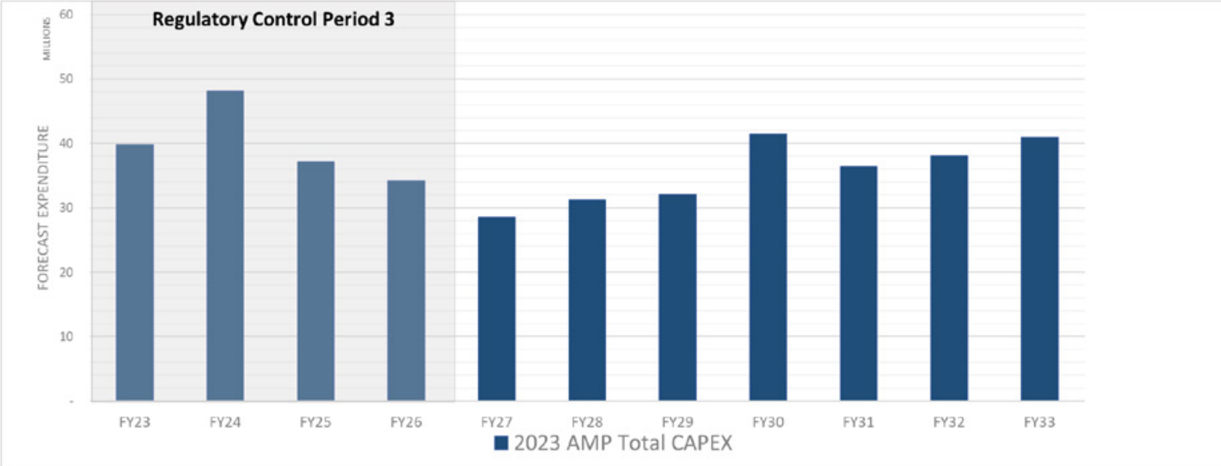
J.3.1. Total Capex

Total Capex includes the following expenditure in the following categories.

- System development Capex investments discussed in Appendix F.
- Lifecycle management Capex investments discussed in Appendix H.
- Investment in non-network assets discussed in Appendix H.

Total forecast Capex for the planning period is shown in Figure 48 below.

Figure 48: Total Capex during the Planning Period



The Capex profile reflects the underlying network needs discussed in this AMP.

Key drivers for the expenditure trend include:

- **Renewals expenditure:**
- **Non-network expenditure**:

The refinement of the asset management approaches has created a steady expenditure profile through the remaining DPP period, with the exception of FY2024, where the drivers for the increased spend is the replacement of Kaitoke compressor unit 1 and the requirement to replace the SCADA master system.

Table 20 below sets out the expenditure per year. These are consistent with Schedule 11a disclosures included in Appendix B.

Table 20: Total forecast Capex during the planning period ($000 in real 2023)

YEAR	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Capex	39,790	48,066	37,192	34,134	28,535	31,195	32,121	42,462	36,399	38,001	40,952

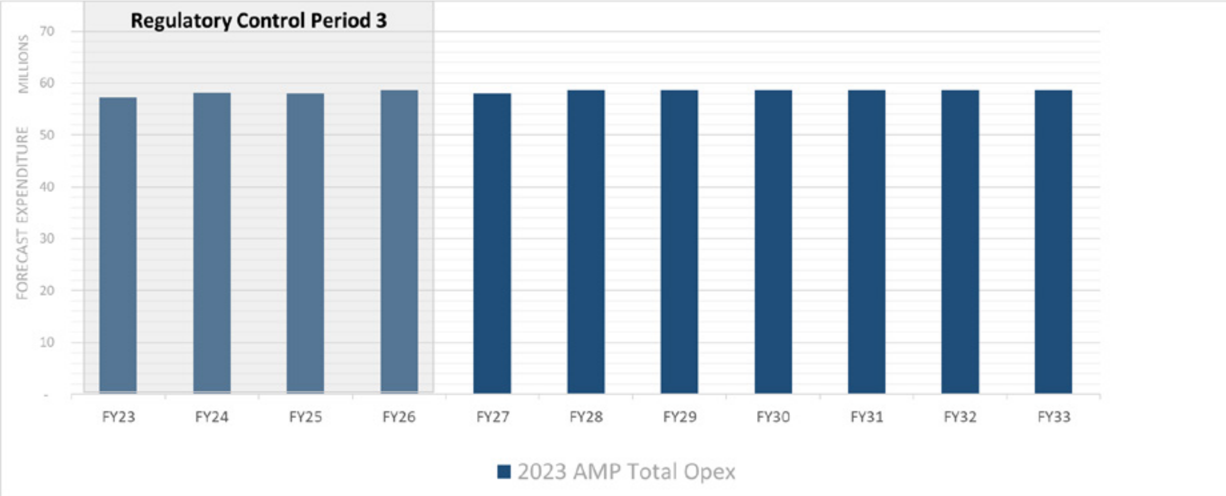
J.3.2. TOTAL OPEX

The Opex forecast includes expenditure relating to the following activity categories discussed in Appendix H:

- Maintenance related expenditure.
- System Operations and Network Support related expenditure.
- Compressor fuel and land management expenses.
- Business support activities.

The total forecast Opex for the planning period is shown in Figure 49 below.

Figure 49: Total Opex during the Planning Period



Opex for the period is generally forecast using FY2023 as a typical (or base) year. Individual forecasts have specific adjustments based on expected activity over the period.

Table 21 below sets out the expenditure per year. These are consistent with Schedule 11b disclosures included in Appendix B.

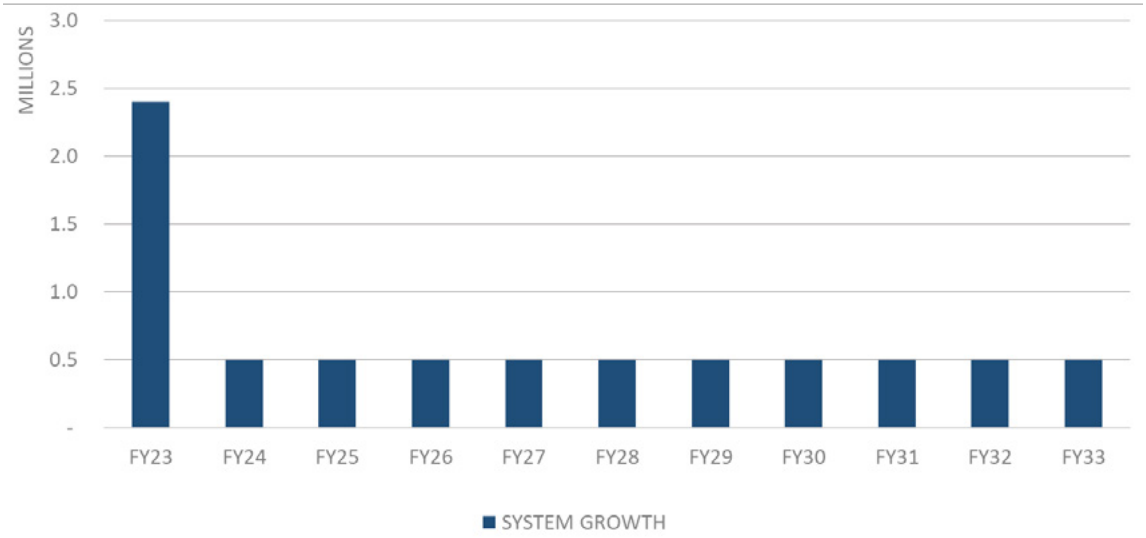
Table 21: Total forecast Opex during the planning period ($000 in real 2020)

YEAR	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Opex	54,632	61,538	61,539	62,062	62,062	62,585	62,585	62,585	62,585	62,585	62,585

J.4. SYSTEM GROWTH CAPEX

In this section expected investments are summarised in system development with further detail on the relevant projects provided in Appendix F.

Figure 50: System Growth Capex during the Planning Period



System development expenditure over the period will be mainly driven by third party requirements. The peak in expenditure in FY2023 is related to expenditure to enable biogas injection into Transmission network. A proportion of the expenditure is also attributed to upgrading assets to enable in-line-inspections to occur on the pipeline. On completion of the work a proportion of the cost may be allocated to asset replacement and renewal expenditure category.

Table 22 below sets out the expenditure per year. These are consistent with Schedule 11a disclosures included in Appendix B.

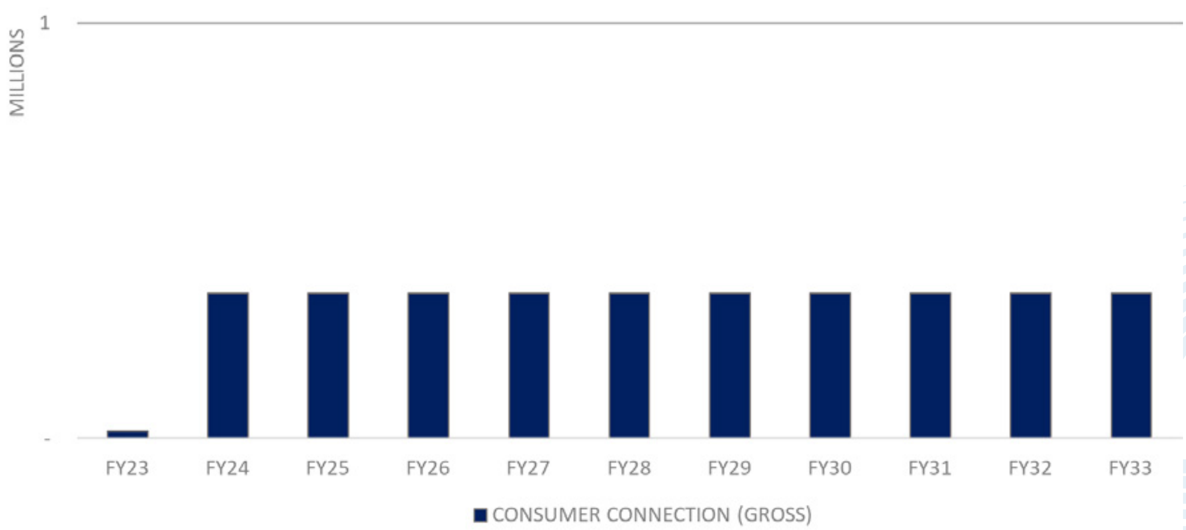
Table 22: System Development Capex during the Planning Period ($000 in real 2023)

YEAR	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPEX	2,398	500	500	500	500	500	500	500	500	500	500

J.5. CUSTOMER CONNECTIONS CAPEX

This section summarises expected investments to enable customer connections.

Figure 51: Total Customer Connection Capex during the Planning Period



Customer Connection expenditure over the period will be mainly driven by third party requirements. For the planning period a baseline amount has been included to allow for the front-end work to be completed should there be a potential customer connection. Potential connections that would require significant one-off investments. These have not been included in forecast as they are not sufficiently developed to include in the forecasts.

Table 23 below sets out the expenditure per year. These are consistent with Schedule 11a disclosures included in Appendix B.

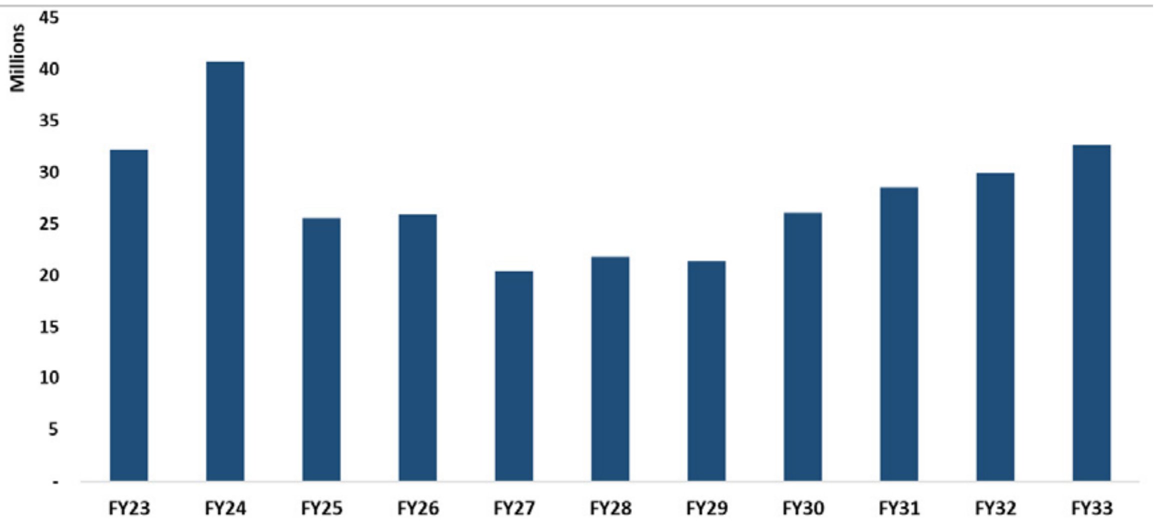
Table 23: Gross Customer Connection Capex during the Planning Period ($000 in real 2023)

YEAR	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPEX	18	350	350	350	350	350	350	350	350	350	350

J.6. ASSET REPLACEMENT AND RENEWAL CAPEX

In this section expected investments to replace and renew asset fleets are summarised with further detail on the included work and associated drivers provided in Appendix H.

Figure 58: Replacement and Renewal Capex during the Planning Period ($000 in real 2023)



Replacement Capex includes replacing assets with like-for-like or new modern equivalents. Renewal Capex is expenditure that extends an asset's useful life or increases its functionality. These investments are generally managed as a series of programmes focused on a particular asset fleet, such as compressors.

As discussed in Appendix H, the key drivers of the expenditure profile over the period are several large projects. These include the following: The network optimisation and compression strategy project and the SCADA master system replacement project.

Table 24 below sets out the expenditure per year. These are consistent with Schedule 11a disclosures included in Appendix B.

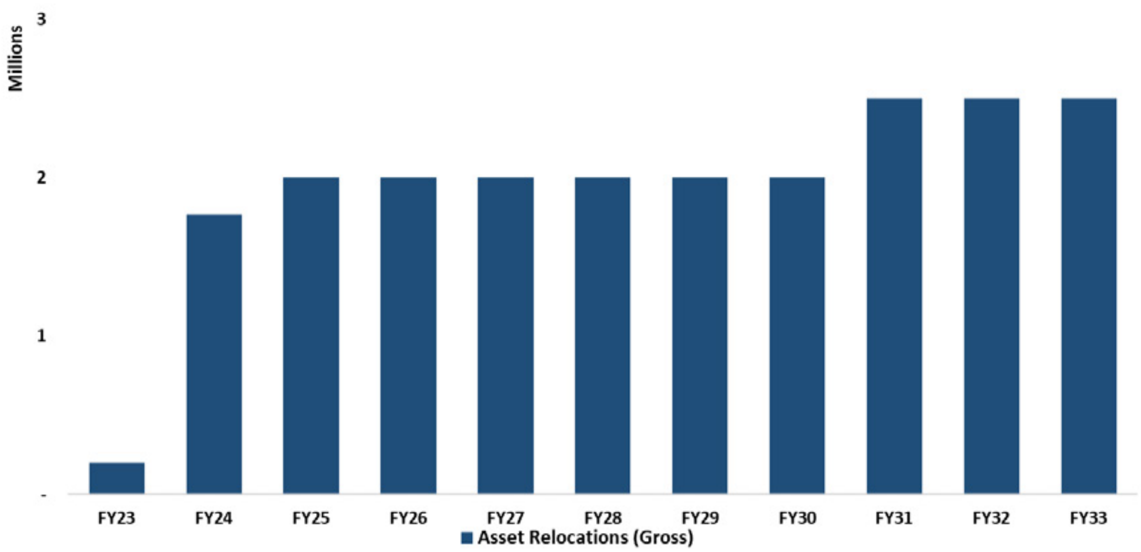
Table 1: Replacement and Renewal Capex during the Planning Period ($000 in real 2023)

YEAR	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPEX	32,178	40,749	25,550	25,900	20,400	21,750	21,400	26,050	28,550	29,900	32,600

J.7. ASSET RELOCATIONS CAPEX

This section summarises expected investments to relocate assets on behalf of third parties. Further detail on this expenditure is provided in Appendix H.

Figure 52: Gross Asset Relocations Capex during the Planning Period



Consistent with average historical trends, forecasting is based on a constant trend of asset relocations Capex over the period. Relocation projects are driven by third party needs and typically align with the customers timelines, as a result, project delivery timing can shift significantly. The uplift towards the end of the planning period is in anticipation of the need to relocate assets due to changing land use and urban development.

Table 25 below sets out the expenditure per year. These are consistent with Schedule 11a disclosures included in Appendix B.

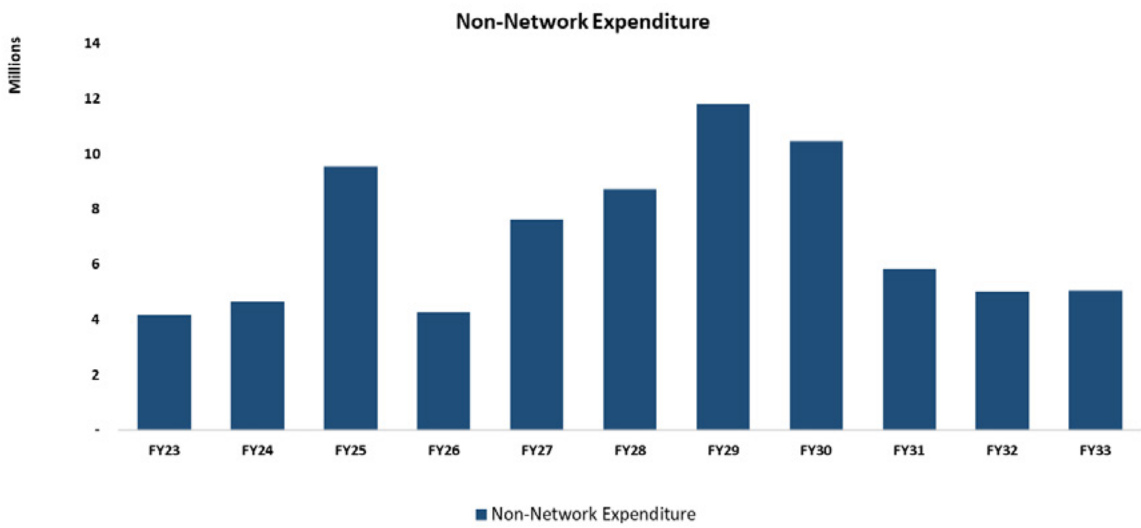
Table 25: Gross Asset Relocations Capex during the Planning Period ($000 in real 2020)

YEAR	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPEX	195	1,767	2,000	2,000	2,000	2,000	2,000	2,000	2,500	2,500	2,500

J.8. Non-Network Capex

This section summarises expected investments in non-network assets to support asset management activities and further detail on the included projects is provided in Appendix H.

Figure 53: Non-network Capex during the Planning Period



Non-network Capex is allocated between Firstgas transmission and distribution businesses based on factors such as size of asset base (RAB) and staff headcount. Over the planning period Firstgas expect to invest in lifecycle-based asset renewals for IT equipment and office assets.

As part of the improvement programme new IT capabilities and office refurbishment in the early years of the period will be invested in. Further detail can be found in Appendix H.

Table 26 below sets out the expenditure per year. These are consistent with Schedule 11a disclosures included in Appendix B.

Table 26: Non-network Capex during the Planning Period ($000 in real 2023)

Year	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
CAPEX	4,147	4,000	8,092	46,84	4,585	5,895	7,421	12,112	4,050	4,301	4,552

J.9. Network Opex

This section summarises the Network Opex expected to incur over the planning period. To align with Information Disclosure, the following expenditure categories are defined.[1]

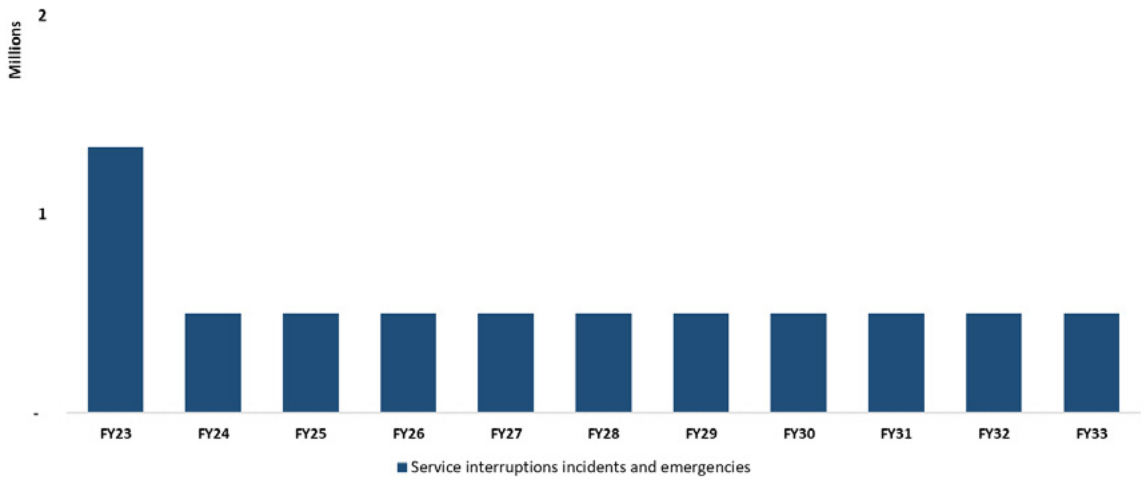
- Service interruptions, incidents and emergencies.
- Routine and corrective maintenance and inspection.
- Compressor fuel.
- Land management and associated activity.

Detail on the activities included in these categories is provided in Appendix H.

J.9.1. Service Interruptions, Incidents and Emergencies

SIE Opex forecast for the planning period is shown in Figure 54 below.

Figure 54: SIE Opex during the Planning Period



It is expected both the cost of undertaking reactive maintenance (SIE) and overall work volumes on the transmission system to remain stable over the period. The exception is FY2023, due to 2 significant weather events that occurred in the first quarter of 2023

Table 27 below sets out the expenditure per year. These are consistent with Schedule 11b disclosure included in Appendix B.

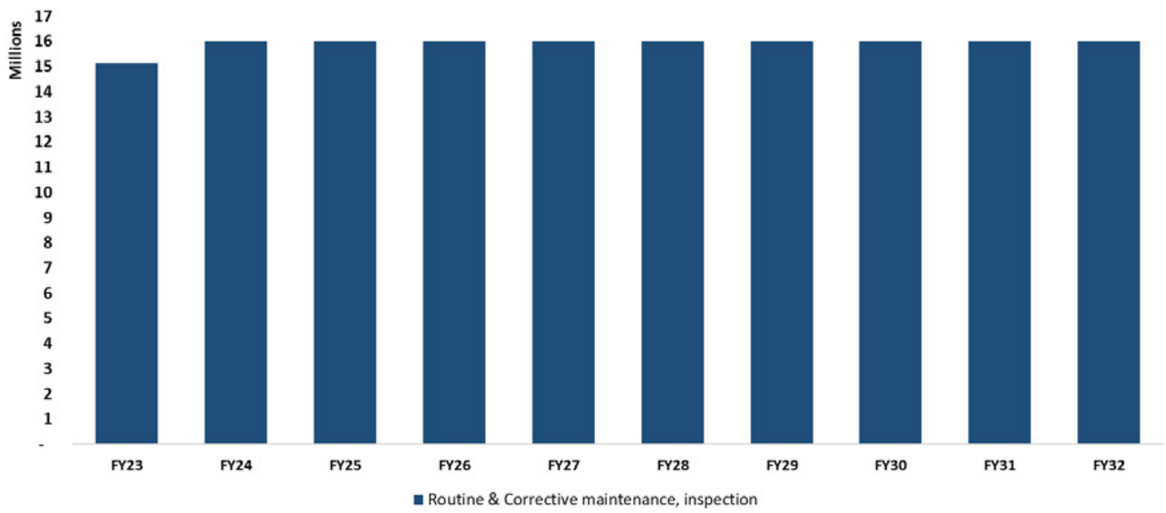
Table 27: SIE Opex during the planning period ($000 in real 2023)

Year	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
OPEX	1,340	501	501	501	501	501	501	501	501	501	501

J.9.2. Routine and Corrective Maintenance and Inspection (RCMI)

RCMI Opex forecast for the planning period is shown in Figure 55 below.

Figure 55: RCMI Opex during the Planning Period



It is expected the cost of undertaking scheduled maintenance to be stable over the period but also expect to see additional cost drivers over the period (see below). However, expenditure has not be increased over the period as it this can be achieved through delivery efficiencies.

Some examples of upward cost pressures are set out below:

- Increases in costs from external service providers
- Significant increases in freight costs
- Significant increases in materials cost

Table 27 below sets out the expenditure per year. These are consistent with Schedule 11b disclosure included in Appendix B.

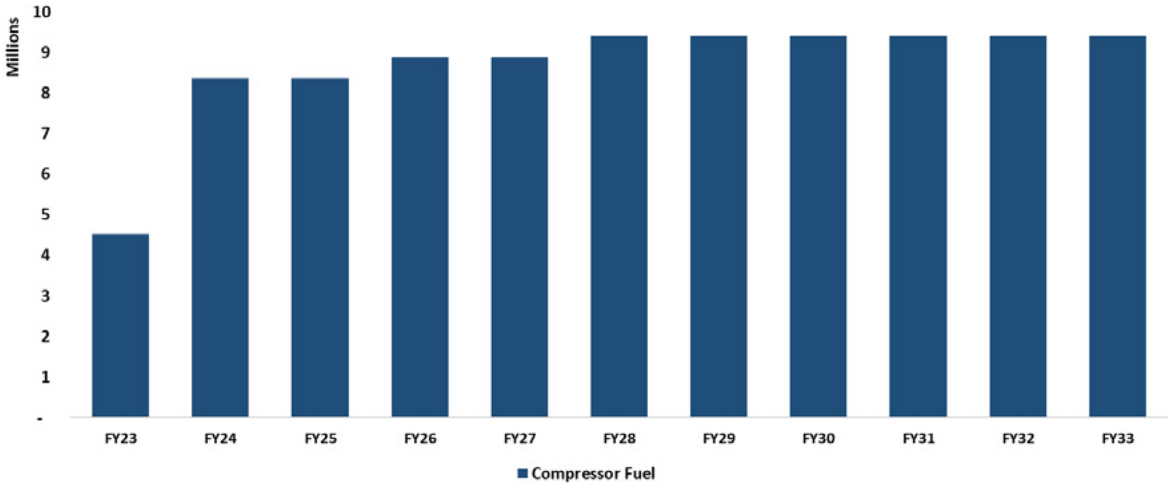
Table 27: RCMI Opex during the planning period ($000 in real 2020)

YEAR	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
OPEX	15,139	16,010	16,011	16,011	16,011	16,011	16,011	16,011	16,011	16,011	16,011

J.9.3. COMPRESSOR FUEL

The Compressor Fuel Opex forecast for the planning period is shown in Figure 56 below.

Figure 56: Compressor Fuel Opex during the Planning Period



The cost of compressor fuel is expected to be largely stable over the period.

Table 28 below sets out the expenditure per year. These are consistent with Schedule 11b disclosures included in Appendix B.

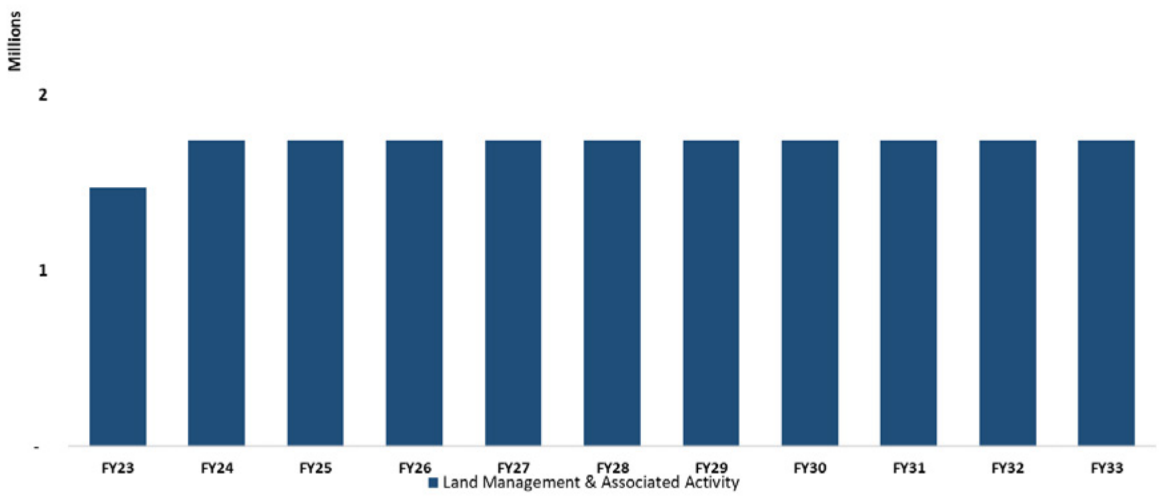
Table 28: Forecast Compressor Fuel Opex during the planning period ($000 in real 2023)

YEAR	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
OPEX	4,537	8,369	8,369	8,892	8,892	9,415	9,415	9,415	9,415	9,415	9,415

J.9.4. Land Management and Associated Activity

The forecast for costs associated with land management during the planning period is shown in Figure 57 below.

Figure 57: Land Management Opex during the Planning Period ($000 in real 2023)



These costs are expected to be stable over the period.

Table 29 below sets out the expenditure per year. These are consistent with Schedule 11b disclosures included in Appendix B.

Table 29: Land Management Opex during the Planning Period ($000 in real 2023)

Year	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
OPEX	1,473	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742

J.10. Non-Network Opex

This section summarises the non-network Opex expected to incur over the planning period. To align with Information Disclosure, wthe following expenditure categories are defined:

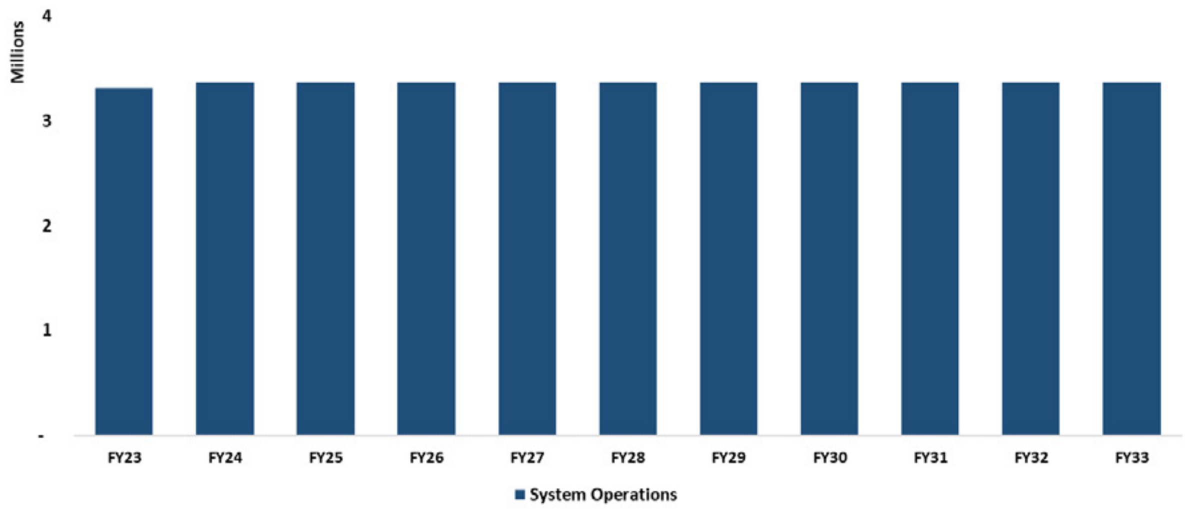
- System Operations
- Network Support
- Business Support

Detail on the activities included in these categories is provided in Appendix H.

J.10.1. System Operations

Our System Operations Opex forecast for the planning period is shown in Figure 58 below.

Figure 58: System Operations Opex during the Planning Period ($000 in real 2023)



Overall costs for System Operations Opex will be consistent with average historical spend.

Table 30 below sets out the expenditure per year. These are consistent with Schedule 11b disclosures included in Appendix B.

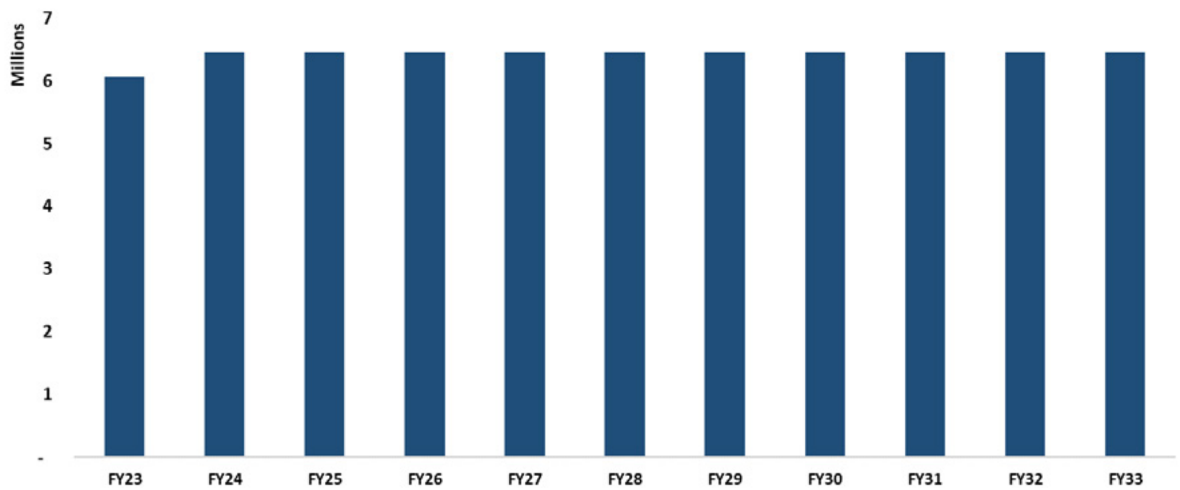
Table 30: System Operations Opex during the planning period ($000 in real 2023)

YEAR	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
OPEX	3,314	3,368	3,368	3,368	3,368	3,368	3,368	3,368	3,368	3,368	3,368

J.10.2. NETWORK SUPPORT

Our Network Support forecast for the planning period is shown in Figure 59 below.

Figure 59: Network Support Opex during the Planning Period ($000 in real 2020)



Appendix K Scheduled Maintenance

In general, the philosophy is to keep assets in use for as long as they can be operated safely, technically and economically. Firstgas maintenance policies support this goal with a comprehensive set of processes, standards and schedules.

This appendix summarises the main scheduled maintenance activities by asset fleet.

K.1. Pipelines Maintenance

Detailed philosophy and guidelines for pipeline maintenance and renewal are contained in the PIMP. The PIMP sets out the pipeline monitoring and maintenance activities to be undertaken to support the safe and reliable operation of the asset.

The PIMP is reviewed annually and considers monitoring data and pipeline activities from the previous year and identifies any change in risks associated with the pipelines from a wide range of threats, which can be broadly categorised as:

- Third party interference
- Corrosion
- Natural events (flooding, earthquakes, slips etc.)

A Safety Management Study (SMS) of the asset was conducted in 2016 in accordance with AS 2885. There are several events or changes which can impact on the pipeline system which may result in a change of the identified risk level and hence maintenance routines. Such changes include:

- Urban encroachment
- Pipeline related incidents
- Findings from routine monitoring
- System improvements
- System modifications
- Inspections and audits

Any required changes to routine maintenance activities identified by the SMS are incorporated into the PIMP and corresponding maintenance schedules. Any required non-routine activities identified by the SMS are registered in the Corrective Actions database or assessed, prioritised and assigned in the Asset Risk Register.

There are several specific pipeline authorisation conditions required as part of the routine maintenance plan. Each of the specific requirements is scheduled as a routine activity. Overall, the asset ages are now approaching mid-life but are considered appropriate for a mature, well-functioning gas transmission pipeline business.

Currently, FGL is running a SMS on a rolling program in a 5-years period. In the below table, the SMS schedule for the next financial year.

Table 32: Safety Management Study Schedule

Pipelines	Area	YEAR	STATUS
715 Pipeline	Taranaki	FY2024	Planning
700 Pipeline and laterals	Manawatu/Hawkesbay	FY2024	Planning
500 Pipeline	Waikato	FY2024	Planning
800 Pipeline and laterals	Bay of Plenty	FY2024	Planning
200 Pipeline and laterals	Taranaki/Waikato/Auckland	FY2025	Scheduled
300 Pipeline and laterals	Taranaki	FY2025	Scheduled
400 Pipeline and laterals	Taranaki/Waikato	FY2025	Scheduled
100 Pipeline and laterals	Taranaki/Manawatu/Wellington	FY2026	Scheduled
430 Pipeline and laterals	Auckland/Northland	FY2026	Scheduled
600 Pipelines and laterals	Taranaki/Manawatu/Wellington	FY2026	Scheduled

Pipeline Surveillance

Regular inspections, aerial surveillance and vehicle/foot patrols are conducted and are scheduled in the ERP system. Non-routine patrols such as post flood/storm and post seismic event inspections are carried out as determined by field technicians and the Transmission Services Manager. Pipeline easement surveillance reports are completed for all patrols. These reports form part of the annual integrity management review.

Pipeline surveillance is used to monitor activities over or near the assets, and in particular, to ensure that no unauthorised activity is occurring or has occurred.

The frequency of pipeline patrols is higher in urban areas. Daily road patrols are the primary surveillance mode in Auckland since most of the pipeline route is located within the road reserves across the isthmus. Road patrols are also carried out monthly in the Whitby area in greater Wellington because of the increased risk of urban developments.

Aerial surveillance features more prominently in the other regions given the rural nature of the pipeline environment.

Aerial inspections of pipelines using helicopters and fixed-wing aircraft are performed in accordance with the PIMP to check for land disturbances, evidence of gas escapes or any unauthorised building, tree planting or construction work over the pipeline easements.

Table 33: Pipeline Surveillance Activities

Frequency	Activity
Daily	Road patrols in Auckland urban area
Monthly	Road patrols in the Whitby area.
Monthly	Road patrols Line flights Surveillance of special areas of interest
Three Monthly	Line flights Surveillance of special areas of interest
Ad Hoc	Post storm, flood or seismic event pipeline route inspections

Technologies now available for pipeline surveillance included unmanned aerial vehicles or drones and use of fibre optic cables buried in pipeline easements to detect activity adjacent to the pipeline. Where possible Firstgas are implementing new technologies if the benefits prove to be advantageous.

Cathodic Protection Inspections

Below inspection schedules are set out:

- Weekday CP rectifier monitoring
- Three monthly CP 'on' monitoring for selected test points
- Six monthly CP Test Point 'on-off' surveys in selected T1 areas
- Yearly CP test point 'on-off' survey of entire system (with the exception of test points to which access was not available at the time e.g. landowner restrictions)
- Yearly cased crossing electrical isolation testing
- Yearly rectifier unit integrity and verification
- Yearly anode bed integrity checks
- Yearly test point inspections
- Yearly ER probe inspections
- 4 Yearly power earthing and bonding check.

Preventative Inspections

Below is a list of typical preventative inspections set out:

- Stress Corrosion Cracking (SCC) investigation/survey
- Coating defect surveys of un-piggable pipelines using Direct Current Voltage Gradient (DCVG) and Alternative Current Voltage Gradient (ACVG) techniques
- Above ground pipe work coating inspections.

Erosion Monitoring

- Erosion monitoring and surveying at selected waterways
- Geotechnical surveys Additional geo-hazard condition monitoring routine inspections are expected to be implemented from FY2018
- Ground movement monitoring.

Reactive Maintenance – Faults and Defects

- Coating faults - inspection, repair and rectification of selected defect indications
- CP - structures and equipment
- Minor third-party damage repairs.

Special Crossings

- Inspection of aerial crossings
- Condition assessment and inspection of selected of cased crossings
- Survey of waterway crossings.

K.2. Compressors Maintenance

Routine maintenance and inspection activities are described in detail in this section for the following asset components contained at compressor stations:

- Gas turbines
- Electrical Motor Driven
- Centrifugal gas compressors
- Reciprocating gas engines
- Reciprocating gas compressors
- Electric drive compressors
- Control systems
- Gas coolers
- Fire and gas protection
- Buildings
- Gas chromatographs
- Associated pipe work
- Valves and regulators

A provision for the improvement of condition monitoring and predictive maintenance practices is included based on the results of recent investigations into component failures.

Routine vibration monitoring is completed on all engine and compressor packages. Frequency of the routine monitoring is based upon criticality of the compression operation.

Gas Turbines

The gas turbines are subject to a "maintenance and overhaul" schedule based upon an Equivalent Operating Hours (EOH) that uses actual operating parameters, number of starts and hours in operation to determine an effective timeframe for specified overhauls. The EOH consumption is based upon the design life of the components from the Original Equipment Manufacturer (OEM). Each start stop cycle consumes some of the creep life of the component; each hour at rated output consumes component life and situations where excess temperatures in the machine through over fuelling etc. and/or surging also consume life. Typically, a start stop sequence incurs a 10-hour penalty and an over firing uses an equivalent of two hours per fired hour.

Maintenance and overhaul intervals have historically followed the OEM fired hour calculations as described above. The OEM calculations and guidelines that trigger invasive maintenance and component replacement do not take into consideration the operational conditions in which the engines typically perform. The engines have generally operated under low loads and below maximum speed and are supplied with clean fuel gas. Further to this it is expected that the engines will for the foreseeable future be running at or near idle as the load downstream of the station has fallen significantly in the past few months.

Firstgas have reviewed the OEM maintenance schedule and have engaged with Turbine Efficiency, an independent turbine specialist, to initiate a condition-based maintenance and overhaul program. Under this regime all components that are normally replaced under the OEM guidelines are inspected and where necessary laboratory analysed and then where prudent are returned to service. Siemens also now offer a more condition-based approach and FGL would usually tender to both companies. It is expected that the engines will achieve their full life expectancy of 48,000 fired hours without the requirement for expensive component replacement.

It is intended to operate the machines equally as the mismatch in EOH offers some degree of protection against age related failure occurring on both machines in close succession.

Table A34: Typical gas turbine maintenance and inspection activities

FREQUENCY	ACTIVITY
8,000 hours	Basic Inspection and replacement of consumables (Type A)
8,000 hours	Inspection and blade sampling.
48,000 hours	Type B + Core exchange (Type C)

The Type A activity is classed as Opex and included in the expenditure forecast. The Type B and Type C overhauls, life extension inspection and blade sampling and core exchange activities are classed as renewal and replacement, capex and expenditure forecasts for these.

The OEM continually monitors the installed fleet service performance and materials technology, to develop retrofit and upgrade parts and materials to extend the life of the machine and components. They will also advise when there is sufficient concern to remove or replace components or parts that have not yet failed, outside of the normal replacement programme.

Firstgas staff do not have the skills or access to the technical documentation required to perform the overhauls, hence the OEM Technical Authority is utilised to oversee the work. Local skilled labour is used to provide the “hands-on” resource, supported by field staff who have received specialist training overseas and form an integral part of the overhaul team, including fault finding.

Predictive maintenance is utilised to monitor the health of the gas turbine, which includes vibration monitoring, temperature monitoring, and oil analysis and bore scope inspections.

Centrifugal Compressors

Centrifugal compressors are also subject to an operating hours-based inspection programme similar to gas turbine inspections. The OEM typically recommend a Type 3 overhaul at 48,000 hours which is assumed to be at a six-year interval. Due to the relative low running hours of the compressors this overhaul occurs at around 24,000 hours, well within the normal life expectancy of the machine. A condition-based approach has been adopted and based upon expert condition assessment expected to operate the machines to their full 48,000 hours, in turn, extending the time between overhauls. In addition, an annual regulatory inspection is carried out by an independent authorised person to verify ongoing compliance with the pressure system regulations. The maintenance and inspection activities are shown below.

Table 35: Centrifugal compressor maintenance and inspection activities

FREQUENCY (EOH)	ACTIVITY
4,000 hours	Visual, seal gas system, valve operation (Type 1)
12,000 hours	Visual, alignment and run out, seal gas inspection (Type 2)
48,000 hours	Bearing replacement, gas seal bundle replacement, visual and valve operation (Type 3)

Reciprocating Engines

Reciprocating machinery is inspected on operating hour intervals. This is based upon OEM (Waukesha) recommendations but has additional points of inspection based upon internal fleet experience. Corrective actions are generally completed during these inspections and the actual cost of the inspection is dependent upon the amount of equipment and components replaced. The maintenance and inspection activity is shown below.

Table 36: Reciprocating engine maintenance and inspection activities

Frequency (EOH)	Activity
2,000 hours	Gaps and clearances, timing
4,000 hours	2,000 hours routine plus replace valves
8,000 hours	4,000 hours routine plus replace valve stem seals

Data gathered during these inspections, such as cylinder compression ratios, clearances and acoustic inspection results are recorded and trended to assist in the evaluation of asset condition in general.

Major overhauls are planned at 60,000 operating hours, the overhaul point is based upon the results of previous inspection data and current condition. Performance monitoring of reciprocating engines is based on weekly performance records compiled by the site technicians for the compressor stations. These reports are used to gather an operating history of the machines and to check for specific deterioration. In addition, a vibration analysis program is operated. Expertise is supplied by a third-party contractor and also utilises Windrock analysis equipment that can provide a detailed condition assessment of both the engine and compressor unit, with in-house capability to operate this equipment.

In-house capability ensures all maintenance tasks can be carried out on the machines, up to refurbishment of major components. The main rotating equipment is fully supported by the OEM who also provides technical oversight for major overhauls. Local industry support is utilised when in-house resources are unavailable, or for larger tasks for which the required equipment is not managed in-house.

Turnaround time for most work is around two to five days, depending on the availability of spares. Due to the fact that a large fleet of similar machines is operated, a reasonable number of spares are held.

Reciprocating Compressors

Reciprocating compressors are inspected in line with the reciprocating engine programme to ensure efficient use of resources and avoidance of staggered inspection down time. Performance analysis of the gas compressors is also undertaken on a quarterly basis to monitor the ongoing performance efficiency. The maintenance and inspection activity is shown below.

Table 37: Reciprocating compressor maintenance and inspection activities

Frequency (EOH)	Activity
4,000 hours	Replace valves
8,000 hours	Replace packing, rings and valves

Electric Drive Compressors

Table 38: Electric drive compressors maintenance and inspection activities

Frequency	Activity
4,000 hours	Replace valves
8,000 hours	Replace packing, rings and valves
2 Monthly	Vibration Monitoring
Yearly	Electric motor and Variable speed drive checks by OEM - ABB Bearing oil, Windings, vibration, VSD logs and filter cleaning

Gas Coolers

Coolers are inspected on a routine basis to ensure efficiency is not being impacted by infestation, nesting or any other foreign bodies that may become entangled in the system and hence affect performance. Coolers are designed with 110% duty capacity to allow up to 10% of system restriction. When the duty capacity falls significantly below 100%, major capital work is required to be performed to allow the cooler to be brought back to specification. The maintenance and inspection activity is shown below.

Due to the ageing profile of the Gas Coolers a remaining life assessment was conducted in FY2017, the recommendations from this report was used to implement a cooler replacement programme.

Table 38: Gas cooler maintenance and inspection activities

Frequency	Activity
Monthly	Ground based visual check for obvious damage or leaks
Six-Monthly	Access to structure for detailed check of tubing, fins and for evidence of any damage or leaks, paint damage or corrosion. Local repair of any concerns
One Yearly	External Corrosion Inspection
10 Yearly	Independent Internal Inspection for Pressure Vessel compliance.

K.3. Main Line Valves (MLVs)

MLVs comprise of multiple components and maintenance requirements are summarised below.

Table 39: MLV maintenance and inspection activities

Frequency	Activity
Six Monthly	Pneumatically operated MLV: operate valve Bypass valves: operate valves and check for leaks Pipe work: inspect for surface corrosion Verify actuator operation, PCV & PSV operation, hand pump operation, check reference tank pressure, check for corrosion, verify LPT setting
Yearly	Solar panels, batteries and regulators: verify operation, cleaning, replace batteries as necessary Verify communication systems and remote valve position (gas control).

K.4. Stations Maintenance

The philosophy and guidelines for maintenance on all station facilities is outlined in the Station Maintenance Management Plan. This document describes the general approach to maintenance, maintenance management model, planning, KPIs, processes, additional strategy elements, performance measurement and spare parts management. All maintenance on stations facilities including individual components is scheduled in a maintenance plan and monitored through the EAM system. The Maintenance Strategy is complimented through a Risk Based Work Selection Process this ensures that maintenance activities are appropriately prioritised, ensuring that those tasks with high-risk profiles are done ahead of lower risk activities.

In order to ensure existing maintenance resources are deployed effectively, a system for conducting a risk-based assessment review of all station maintenance activity has been completed. The aim of the review is to prioritise all maintenance activity so that resources can be assigned to the highest risk activities and the implications of deferrals can be fully understood and documented.

Where applicable, pressure vessels are inspected to the requirements accordance with AS/NZS 3788: 2006 Pressure Equipment In-Service Inspection and maintained in accordance with document Pressure Equipment Management Plan. This document sets out the requirements for inspection intervals, competent person requirements, non-conformance reporting and standards to be applied.

Station maintenance and inspection activities are described in the following sections for each class of asset.

Heating Systems

Heating systems are integral station components and ensure that gas delivered meets the temperature requirement in NZS5442. Regular checks and maintenance are essential to ensure ongoing safety and reliability.

Smaller gate stations and compressor stations have smaller heaters which typically use pneumatic controls. They still use the same technology as when first installed, and the components remain easily maintainable and readily available. Pneumatic devices performing protective and control functions require a reasonable degree of cleanliness and lubrication to function correctly. This requires periodic overhaul, cleaning and replacement of soft parts (as required).

Heater system outages are usually detected by a flame failure alarm or low temperature alarm from either SCADA or Autopoll or detected during scheduled maintenance and inspection.

WBHs are internally inspected every 10 years to assess their condition and to carry out any identified remedial work.

Heating systems comprise of several components and maintenance requirements and are summarised below.

Table 40: Heating system maintenance and inspection activities

Frequency	Activity
Six Monthly	**WBH** Verify water level, burner operation and temperature control. Rectify as necessary **All heating systems:** Inspect paint condition, instrumentation for corrosion
Yearly	**WBH**

Frequency	Activity
	PCV and PSV operation, instrumentation operation, shut-off valve operation, high temperature trip, low water level trip, water condition sampling **Electric heating systems** Verify operation and trip functions. Check operation of elements Check calibration of thermocouples and temp transmitters. Check terminations for tightness
Two Yearly	**WBH** Replace UV lamps (where installed)
As required	**WBH** Cleaning and overhaul of pneumatic control devices
Ten Yearly	**WBH** In situ Inspection
20 years	**WBH** Removal and Inspection
30 years	**WBH** In situ Inspection
40 years	**End of life assessment – Asset to be replaced**

Odorisation Plants

Odorant vessels are managed under the Pressure Equipment Management Plan to meet and inspected in accordance with AS/NZS 3788: 2006 Pressure Equipment In-Service Inspection. Odorant plants are also certified under the requirements of the Hazardous Substances and New Organisms Act 1996 (HSNO).

Bulk odorant supplies are imported and distributed to the odorant storage tanks.

Odorisation plants comprise of a number of components and maintenance requirements are summarised below.

Table 41: Odorisation plant maintenance and inspection activities

Frequency	Activity
Monthly	Instrumentation and pumps - verify operation Odorant quantity visual inspection, top up as necessary
Six Monthly	Odorant operational checks
Yearly	Odorant vessel (fixed) external inspection Instrument PCV checks Location test certificate renewal
Two Yearly	Odorant vessel (transportable) external inspection Odorant injection pump overhaul
Five Yearly	PSV testing verification
Ten Yearly	Odorant vessel (transportable) internal inspection

Coalescers and Filter/Separators

Coalescers and filter/separators are managed under the Pressure Equipment Management Plan and inspected in accordance with AS/NZS 3788: 2006 Pressure Equipment In-Service Inspection.

Accredited Agency internal inspection intervals are recommended by the inspection body and are based on inspection history. Coalescers comprise of several components and maintenance requirements are summarised below.

Table 42: Coalescer maintenance and inspection activities

FREQUENCY	ACTIVITY
Six Monthly	Check operation and physical condition of level switches, dump valves and pressure controllers. Visual inspection of external surfaces for corrosion
Yearly	Check operation of high-level protection or alarms and recalibrate as necessary
Two Yearly	Statutory external vessel inspection
Four Yearly	Internal visual inspection of accessible vessels. 10% radiography of inaccessible vessels (vessels nominated by Accredited Agency, depending on service and Inspection agency recommendations), filter element replacement
Five Yearly	Maximum frequency of statutory testing by an accredited agency of pressure vessel protecting equipment.
Ten Yearly	Internal visual inspection of accessible vessels and 10% radiography on inaccessible vessels. (vessels nominated by Accredited Agency, depending on service and Inspection agency recommendations)

Metering Systems

The gas metering systems (GMSs) are operated, maintained and inspected in accordance with the Metering Requirements for Receipt and Delivery Point standard, Metering Equipment Operation and Maintenance Plan.

Metering systems are calibrated at frequencies and to limits that are required by applicable codes, standards and manufacturers' recommendations.

Firstgas has developed a meter maintenance and inspection strategy, which is a significant deviation from the historical approach. Currently the maintenance is transitioning over to the new regime.

Metering Systems comprise of several components and maintenance requirements are summarised below.

Table 43: Metering systems maintenance and inspection activities

FREQUENCY	ACTIVITY
Monthly	Base volume indication (BVI), correction factor indication (CFI)and Primary Flow Signal Integrity (PFSI) checks
Three Monthly (Large Station)	All meter types: Series – Prove test. Ultrasonic and Coriolis meter: Electronic accuracy checks. Turbine & Rotary meters: Verify operation & lubrication. Corrector: Verify operation Flow Computer: Verify operation Transmitter: Verify operation
Six Monthly (Small Station)	Turbine, Rotary & Diaphragm meters: Verify operation & lubrication. Corrector: Verify operation
Yearly	Flow Computer & transmitter: Calibrate
Two Yearly (More frequent for some sites)	Turbine meter: Exchange, refurbish & calibrate

Three Yearly	Corrector: Exchange, refurbish & calibrate
Five Yearly	Rotary & Diaphragm meter: Exchange, refurbish & calibrate
Eight Yearly	Coriolis meter: Factory re-calibration
Ten yearly	Ultrasonic meter: Factory re-calibration

The revised maintenance strategy will reduce the on-going maintenance requirements for the fleet of meters. Until fully implemented, existing maintenance and inspection activities will remain in effect.

SCADA and Communications

The SCADA master station and communications systems located at Bell Block are regularly tested, maintained. Field devices and associated control system are maintained, inspected and calibrated by the Transmission Services team.

Improvements in technology are making control systems more reliable and able to perform self-diagnostics. These features also permit a decrease in maintenance frequency. The aim is to achieve the scenario where the majority of maintenance is preventative and the minority due to breakdowns. Firstgas will work with communication service providers to migrate to fibre-based communications media solutions at remote stations. Fibre solutions will align with the future direction and maintainability of the service provider.

SCADA and communications equipment comprise of several components and maintenance requirements are summarised with activities listed below.

Table 44: SCADA and communications maintenance and inspection activities

Frequency	Activity
Master Station Weekly	System performance checks Communication reliability checks
Master Station Monthly	History archiving checks System back-up initiated DR updated
Master Station Three Monthly	Wireless probe System log checks System security checks
RTU Yearly	Inspection, performance and calibration checks
RTU Two Yearly	Full calibration Equipment card/component checks

Gas Chromatographs (GCs)

Gas Chromatographs are operated, maintained and inspected under the Metering Requirements for Receipt and Delivery Point standard.

GCs comprise of a number of components and maintenance and inspection requirements are summarised below.

Table 45: GC maintenance and inspection activities

Frequency	Activity
Weekly	Auto calibration

Monthly	Verify calibration results, verify sampling system and carrier gas system operation, change filtration elements
Yearly	Change filtration elements, visual inspection of shelter Pipeline gas comparison check
As required	Exchange carrier gas or calibration gas bottles

PIG Launchers and Receiver

PIG launchers and receiver's maintenance and inspection requirements are summarised below.

Table 46: PIG launcher and receiver maintenance and inspection activities

FREQUENCY	ACTIVITY
Six Monthly	Visual external inspection as part of routine station checks
Two Yearly	Internal inspection Inspection of door sealing assemblies Leak test of door sealing assemblies

Station Pressure Regulators

Pressure regulators are either a single assembly or have a pilot valve to control operation. Pressure regulators are maintained in similar a similar way as summarised below.

Table 47: Pressure regulator maintenance and inspection activities

FREQUENCY	ACTIVITY
Six Monthly	Verify operation of monitor and standby streams, record set values 'as found' and 'as left' (excluding control valves) Test lock up of regulators Inspect valve and mounting arrangements for evidence of corrosion
Yearly	Control valves Verify operation and record set values 'as found' and 'as left' Stroke check valve positioner on pressure control valve Check instrument gas supply regulators
As required	Overhaul regulator valve, overhaul pilot valve, overhaul control valve

Pressure Safety Valves (PSVs)

PSVs are either a single assembly or have a pilot valve to control operation. Pressure relief valves regardless of type are maintained in a similar way as summarised below.

PSVs testing frequency is determined by the Pressure Equipment Management Plan in accordance with AS/NZ 3788: 2006 Pressure Equipment In-Service inspection. PSVs will have varying frequency of test. Routine testing frequency is assigned upon the reliability of the As Found Lift Test results being within specification for that specific PSV.

Table 48: PSV maintenance and inspection activities

Frequency	Activity
Routine Test	Verify operation and record set values 'as found' and 'as left' Test operation of monitor and standby stream PSVs Inspect valve and mounting arrangements for evidence of corrosion. Leak check
Five Yearly	Overhaul relief valve and pilot assembly

Pilot Valves

Pilot valves are usually considered as a sub assembly of the valve that they control, typically pressure control valves and pressure relief valves. Their maintenance and upkeep is therefore included within the schedules of the larger assemblies.

Isolation Valves

Isolation valves maintenance and inspection is summarised below.

Optimal maintenance practice currently requires clarification. Advice from OEMs and valve specialists is not consistent and consequently does not always align with documented instructions given to field technicians. This may result in changes to maintenance and inspection frequencies and activities.

Table 49: Isolation valve maintenance and inspection activities

Frequency	Activity
Yearly	Cycle Valve, lubricate if required, check seat tightness and leak check.
Condition Based Maintenance	Overhaul gas actuator

Filters

Filters regardless of size largely require little maintenance and is summarised below.

Table 50: Filter maintenance and inspection activities

Frequency	Activity
Two Yearly	Inspect and replace element if necessary

Electrical Equipment in Hazardous Areas

Maintaining a "Verification Dossier" of all hazardous area electrical installations is a requirement as laid out in AS/NZS 60079.14 and AS/NZS 60079.17. It is the collection of various design, purchasing, compliance, maintenance, inspection and re-inspection documents needed to ensure that any electrical installation in a hazardous area is compliant with standards, is installed in a safe fashion and will pass an audit.

Three-yearly interval re-inspection is required on all sites, and to the level of detail of each piece of hazardous area certified equipment on each site. Corrective work may arise from re-inspections, which is largely due to environmental impact and deterioration. However, from time-to-time items such as flame path damage on junction boxes can necessitate replacement on larger items.

On some older stations hazardous area certified electrical equipment was certified to old USA or Canadian standards. This equipment is not now recognised for use in New Zealand without additional supporting documentation and engineering approval.

Station Recoating

The coating inspection and review process was put in place in 2015. Station painting is prioritised on condition and criticality, ensuring that the highest risk coating issues will be addressed.

Station Ancillaries

Station ancillary maintenance and inspection is summarised below:

Table 51: Filter maintenance and inspection activities

DESCRIPTION	FREQUENCY	ACTIVITY
Land, security fences (including gates), lighting, signage and buildings	Six Monthly	General station inspection Weed control
Power, Earthing and Bonding Systems	Two or Three Yearly	Sites with RTUs installed. Inspection and maintenance
General Cabling, Cable Trenches, Cable Support Systems, Junction Boxes	Four Yearly	Sites with no RTUs installed Inspection and maintenance to documents
General Instrumentation not associated with other asset categories	Monthly	Transfer of data back to the Gas Control Room at Bell Block via the SCADA system.
	4 Yearly	Alarm or Indicating Instrumentation Calibration
Piping and pipe supports - Above Ground	Two Yearly	Inspection is carried out by a coating specialist
Gas Detection Equipment (not associated with compressor units)	Yearly	General inspection and function checks Calibration of sensors
General Corrosion Remediation	As Required	Corrosion anomalies are reported, reviewed and prioritised on a regular basis via the Anomaly Review Process.

Critical Spares

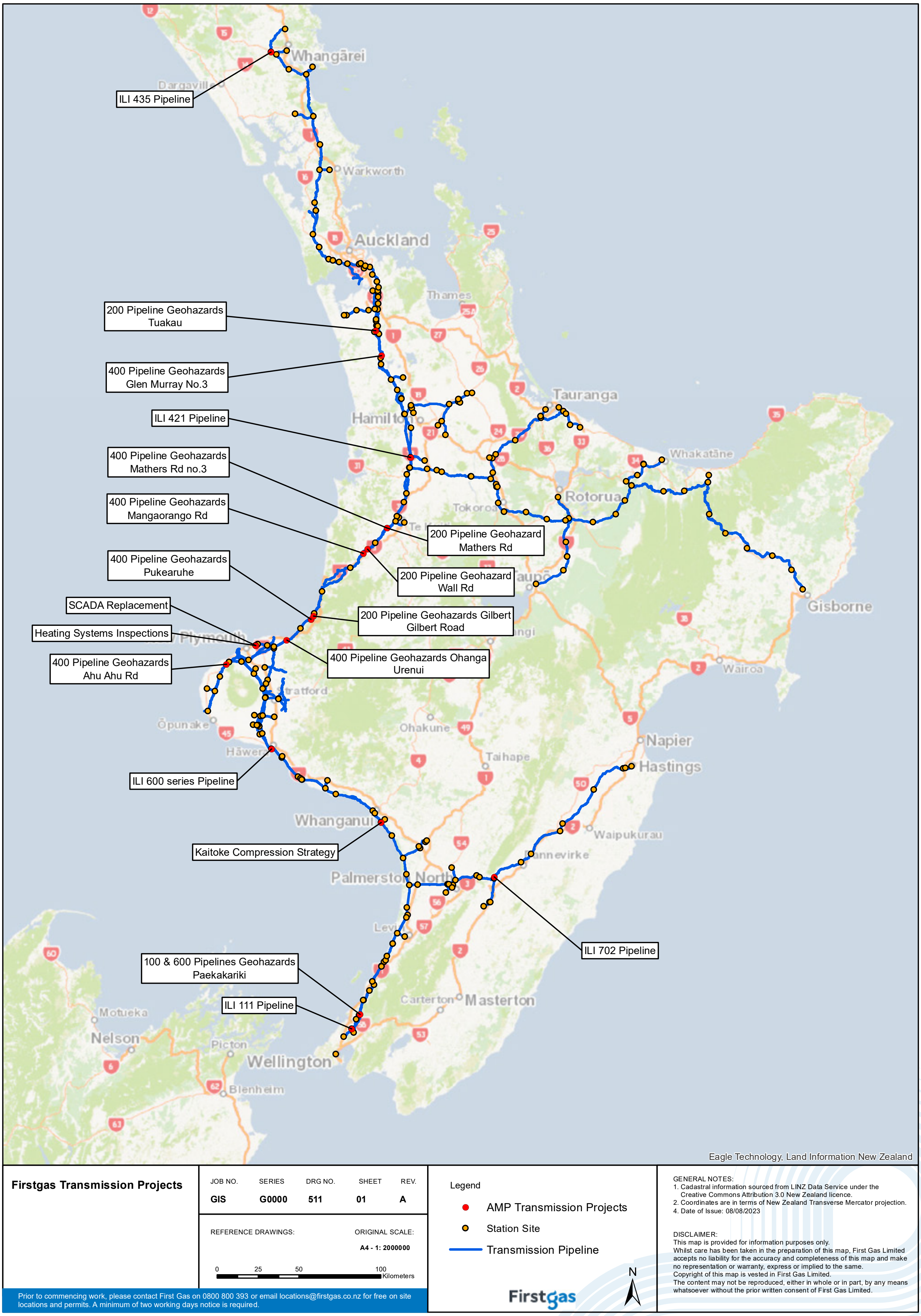
Critical spares are subject to compliance with technical standards and processes for their acquisition, management and maintenance.

Critical spares are subject to regular maintenance and inspection.

K.5. Maintenance Activities Forecast Expenditure ($000's)

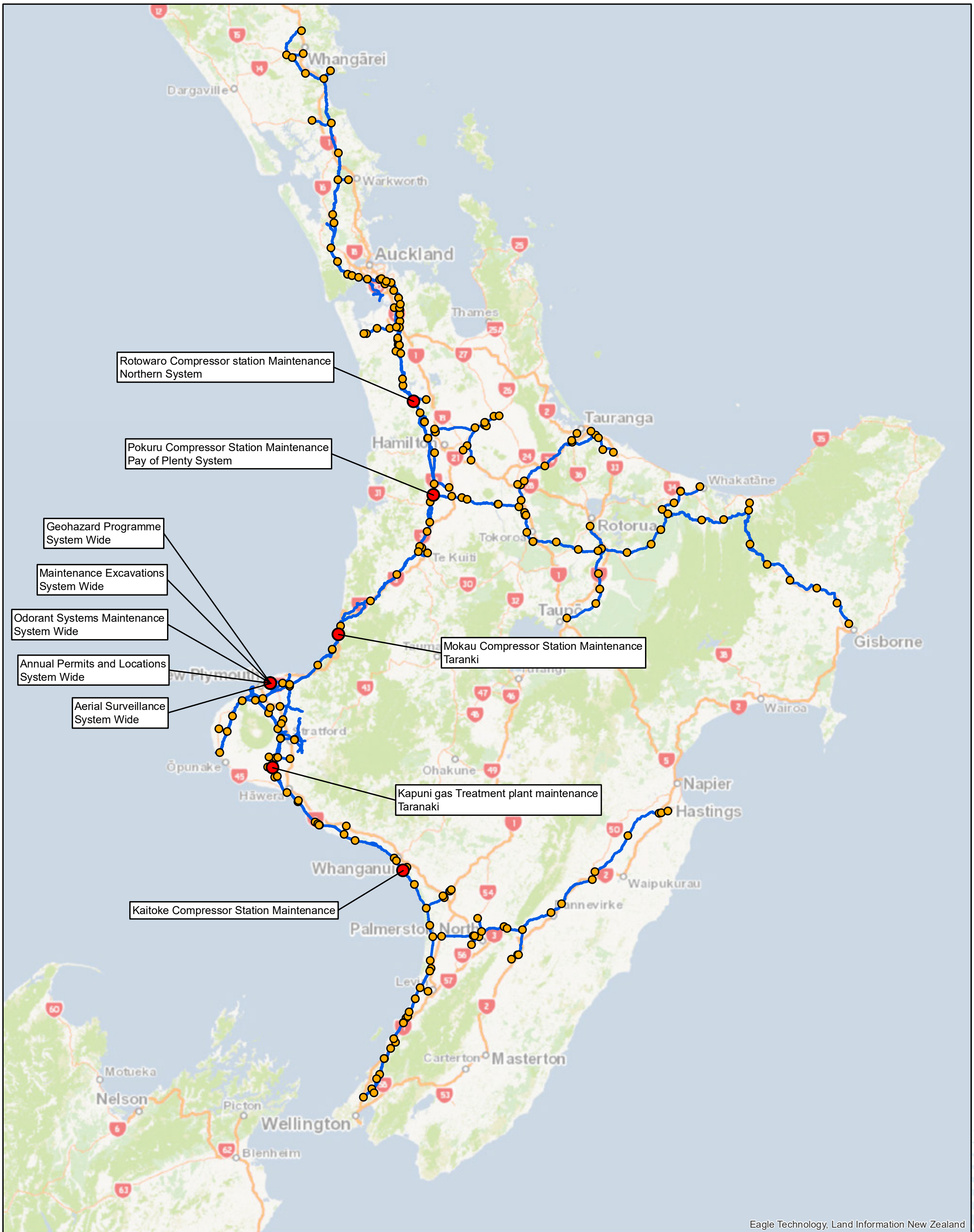
Expenditure Description	Financial Years ($000's)									
	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
RCMI- Pipelines	2,821	2,821	2,821	2,821	2,821	2,821	2,821	2,821	2,821	2,821
RCMI- Compressors	3,420	3,421	3,421	3,421	3,421	3,421	3,421	3,421	3,421	3,421
RCMI- Stations	9,209	9,209	9,209	9,209	9,209	9,209	9,209	9,209	9,209	9,209
RCMI -Special Crossings	41	41	41	41	41	41	41	41	41	41
RCMI- SCADA and communications	20	20	20	20	20	20	20	20	20	20
RCMI- Plant and equipment	500	500	500	500	500	500	500	500	500	500
RCMI -Total	**16,010**	**16,011**	**16,011**	**16,011**	**16,011**	**16,011**	**16,011**	**16,011**	**16,011**	**16,011**
Compressor Fuel	8,369	8,369	8,892	8,892	9,415	9,415	9,415	9,415	9,415	9,415
Land Management and Associated Activities	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742	1,742
Service Interruptions Incidents and Emergencies	501	501	501	501	501	501	501	501	501	501
Total	**26,622**	**26,623**	**27,146**	**27,146**	**27,669**	**27,669**	**27,669**	**27,669**	**27,669**	**27,669**

Appendix L Significant Projects



Significant CAPEX expenditure through period

Activity	Description	Regions	Period	Total Cost
Kaitoke Network Optimisation	Compression optimisation and replacement	Kaitoke Compressor Stn	FY23- FY24	$27m
SCADA Replacement Project	Asset Replacement	Bell Block	FY23- FY24	$9m
Geohazard - 400 Pipeline – Ohanga, Urenui	Geohazard Risk Remediation	Taranaki	FY24/FY25	$0.5m
Geohazard - 400 Pipeline – Ahu Ahu Road, Taranaki	Geohazard Risk Remediation	Taranaki	FY24/FY25	$0.5m
Geohazard - 400 Pipeline, Pukearuhe	Geohazard Risk Remediation	Taranaki	FY24/FY25	$0.5m
Geohazard - 200 Pipeline, Tuakau	Geohazard Risk Remediation	Waikato	FY24/FY25	$0.5m
Geohazard - 100 & 600 Pipelines – Paekakariki	Geohazard Risk Remediation	Paekakariki	FY24/FY25	$0.5m
Geohazard - 400 Pipeline - Feature 3, Glen Murray	Geohazard Risk Remediation	Waikato	FY24/FY25	$0.5m
Geohazard - 200 Pipeline, Gilbert Road	Geohazard Risk Remediation	Taranak	FY24/FY25	$0.5m
Geohazard – 400 Pipeline - Mangaorango Rd	Geohazard Risk Remediation	Waikato	FY24/FY25	$0.5m
Geohazard - 200 Pipeline - Feature No. 4 Mathers Road	Geohazard Risk Remediation	Waikato	FY24/FY25	$0.5m
Geohazard – 400 Pipeline Feature No.3 Mathers Road	Geohazard Risk Remediation	Waikato	FY24/FY25	$0.5m
Geohazard – 200 Pipeline – Feature No.4 Wall Road	Geohazard Risk Remediation	Waikato	FY24/FY25	$0.5m
Heating systems	Heating System inspection maintenance and Refurbishment	System Wide	FY24 – FY28	$0.7m /year
In-Line-Inspection 702 Pipeline	Pipeline Integrity management	Foley Road offtake to Pahiatua delivery point	FY2024	$4.7m/year
In-Line-Inspection 435 Pipeline	Pipeline Integrity management	Maungatapere Main Line Valve to Kauri Delivery point	FY2024	
In-Line-Inspection 421 Pipeline	Pipeline Integrity management	Pirongia to Te Awamutu North Dp	FY2024	
In-Line-Inspection 111 Pipeline	Pipeline Integrity management	Waitangirua DP to TAWA A delivery point	FY2024	
In-Line-Inspection 600 series loop lines	Pipeline Integrity management	Hawera to Kaitoke Compressor Station. This is broken up into 4 sections that will be pigged independently	FY2024	



Firstgas Transmission Projects

JOB NO.	SERIES	DRG NO.	SHEET	REV.
GIS	G0000	511	03	A

REFERENCE DRAWINGS:

ORIGINAL SCALE: A4 - 1: 2000000

0 25 50 100 Kilometers

Prior to commencing work, please contact First Gas on 0800 800 393 or email locations@firstgas.co.nz for free on site locations and permits. A minimum of two working days notice is required.

Legend

- AMP Transmission Projects
- Station Site
- Transmission Pipeline

N

Firstgas

GENERAL NOTES:
1. Cadastral information sourced from LINZ Data Service under the Creative Commons Attribution 3.0 New Zealand licence.
2. Coordinates are in terms of New Zealand Transverse Mercator projection.
4. Date of Issue: 21/09/2023

DISCLAIMER:
This map is provided for information purposes only.
Whilst care has been taken in the preparation of this map, First Gas Limited accepts no liability for the accuracy and completeness of this map and make no representation or warranty, express or implied to the same.

Significant opex expenditure through period

Activity	Description	Regions	Period	Total Cost
Aerial Surveillance	Helicopter and Fixed Wing Surveillance	System Wide	FY2024 - FY2033	$14.1m
Kapuni gas Treatment plant maintenance	Ongoing maintenance associated with assets at gas treatment Plant	Taranaki	FY2024 - FY2033	$13.3m
Geohazard Programme	Inspection, monitoring and assessment of Geohazard Features	System Wide	FY2024 - FY2033	$8.5m
Maintenance Excavations	Defect excavations and inspection	System Wide	FY2024 - FY2033	$7.2m
Annual Permits and Locations	Permitting and locations of pipeline works	System Wide	FY2024 - FY2033	$6.5m
Rotowaro Compressor station Maintenance	Ongoing maintenance costs associated with assets on site	Northern System	FY2024 - FY2033	$5.9m
Mokau Compressor Station Maintenance	Ongoing maintenance costs associated with assets on site	Taranki	FY2024 - FY2033	$2.8m
Pokuru Compressor Station Maintenance	Ongoing maintenance costs associated with assets on site	Pay of Plenty System	FY2024 - FY2033	$2.4m
Odorant Systems Maintenance	Maintenance Costs associated with odorant systems	System Wide	FY2024 - FY2033	$2.4m
Kaitoke Compressor Station Maintenance	Ongoing maintenance costs associated with assets on site	Southern System Maintenance	FY2024 - FY2033	$2.2m

Appendix M Regulatory Compliance Report

This table provides a look-up reference for each of the information disclosure requirements described in the Gas Transmission Information Disclosure Determination 2017 (consolidated 3 April 2018), including attachments and schedules.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP Section identifies where compliance addressed
	Disclosure relating to asset management plans and forecast information
2.6.1 Subject to clauses 2.6.3, before the start of each disclosure year, every GTB must: (1) Complete an AMP that: (a) relates to the gas transmission services supplied by the GTB. (b) meets the purposes of AMP disclosure set out in clause 2.6.2. (c) has been prepared in accordance with Attachment A to the Gas Transmission Information Disclosure Determination document. (d) contains the information set out in the schedules described in clause 2.6.6. (e) contains the Report on Asset Management Maturity as described in Schedule 13.	(1) (a) *Section 1* of the AMP Summary Document describes the purpose of the Transmission AMP and how the AMP correlates to the Firstgas gas transmission system network. (b) and (c) Compliance with Clause 2.6.2 and Attachment A – Asset Management Plans of the *Gas Transmission Information Disclosure Determination*, is summarised in the AMP Summary Document and explained in greater detail in the accompanying appendices to the document, as noted below. (d) The schedules required in clause 2.6.6 are included in *Appendix B - Information Disclosure Schedules* of the AMP and provided to the Commission in native format. Expenditure for the planning period is summarised in *Section 5* of the AMP Summary Document. Other information from the schedules on asset condition and forecast demand is also included, where relevant, in the AMP. *Appendix C – C1.1 - Network Overview* provides information on the condition of asset fleet. (e) The AMMAT report (Schedule 13) is included in *Appendix B* of the AMP.
(2) Complete the Report on Asset Management Maturity in accordance with the requirements specified in Schedule 13.	(2) The Company's approach to asset management is described in *Sections 2, 3 and 4* of the AMP Summary Document. Further detail on the Company's asset management approach is provided in *Appendix H - Asset Management Approach – H.1-H.3.14* and the AMMAT report (Schedule 13) is included in *Appendix B*.
(3) Publicly disclose the AMP.	(3) The AMP Summary Document and its appendices are publicly available on the Firstgas website (www.firstgas.co.nz).
2.6.2 The purposes of AMP disclosure referred to in subclause 2.6.1(1)(b) are that the AMP:	(1)
(1) Must provide sufficient information for interested persons to assess whether: (a) assets are being managed for the long term. (b) the required level of performance is being delivered. (c) costs are efficient and performance efficiencies are being achieved.	(a) - (c) The AMP includes the following information: • The purpose of the AMP outlined in *Section 1* of the AMP Summary Document. • *Sections 2,3 and 4* of the AMP Summary Document includes the Company's asset management improvement programme. This explains the approach on how assets are managed throughout their life cycle and how costs and performance efficiencies are maximised. More detail on the asset management approach is available in *Appendix H - Section H3 Asset Management System*. • *Section 3* of the AMP Summary Document outlines the system development and improvement work Firstgas continues to undertake, while *Section 7* sets out the significant major projects planned for the coming financial year. Further detail on the system development programme for the 10-year planning period is available in *Appendix F - System Development*. • Performance Measures and Targets are included in *Appendix H – Section H5 Performance Measures*.
(2) Must be capable of being understood by interested persons with a reasonable understanding of the management of infrastructure assets.	(2) The AMP has been structured and presented in a manner that is intended to be easily understood by interested persons with a reasonable understanding of the management of infrastructure assets. This includes: • Details of the asset management plan are located in the appendices leaving the AMP Summary Document to deliver the core messages of the AMP • Using common terminology • Inclusion of less common terms can be found in *Appendix A – Glossary* to assist understanding of terminology used throughout the AMP documents • Clear description of expenditure forecasts presented in the AMP.
(3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks.	(3) Risk management policy, framework and high-level risks are included in *Appendix H - Section H3 - Asset Management System*. The path between asset criticality and health, risk mitigation and resulting expenditure are also included. Further detailed risks and issues are included in *Appendix C – Network Overview* against each related asset section.
Clauses 2.6.3 to 2.6.5 relate to AMP updates. 2.6.3 Subject to clause 2.6.4, a GTB may elect to complete and publicly disclose an AMP update, as described in clause 2.6.5, before	Firstgas has provided a full AMP this year.

the start of a disclosure year, instead of an AMP, as described in clause 2.6.1(1), unless the start of that disclosure year is- (1) between 6 (inclusive) and 18 months after the start of the DPP regulatory period; or (2) between 18 (inclusive) and 30 months before the start of the next DPP regulatory period.	
2.6.4 A GTB must not complete and publicly disclose an AMP update instead of an AMP if it has not previously publicly disclosed an AMP under clause 2.6.1.	Firstgas has provided a full AMP this year.
2.6.5 For the purpose of clause 2.6.3, the AMP update must: (1) Relate to the gas transmission services supplied by the GTB; (2) Identify any material changes to the network development plans disclosed in the last AMP under clause 14 of Attachment A or in the last AMP update disclosed under this clause; (3) Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP pursuant to clause 15 of Attachment A or in the last AMP update disclosed under this clause; (4) Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b; (5) Provide an assessment of transmission capacity as set out in clause 8 of Attachment A; (6) Identify any material changes related to the legislative requirements as set out in clause 3.6 of Attachment A; (7) Identify any changes to the asset management practices of the GTB that would affect a Schedule 13 Report on Asset Management Maturity disclosure; and (8) Contain the information set out in the schedules described in clause 2.6.6.	Firstgas has provided a full AMP this year.
2.6.6 Before the start of each disclosure year, each GTB must complete and publicly disclose each of the following reports by inserting all information relating to the gas transmission services supplied by the GTB for the disclosure years provided for in the following reports: (1) the Report on Forecast Capital Expenditure in Schedule 11a. (2) the Report on Forecast Operational Expenditure in Schedule 11b. (3) the Report on Asset Condition in Schedule 12a. (4) the Report on Forecast Demand in Schedule 12b.	The expenditure forecasts are summarised in the AMP Summary Document - *Section 8 - Expenditure Forecast*. The required reports are included in *Appendix B* of the AMP Summary Document and have been provided to the Commerce Commission in native format.
Attachment A: Asset Management Plans	
Section AMP Design	
1. The core elements of asset management: 1.1 A focus on measuring network performance and managing the assets to achieve service targets. 1.2 Monitoring and continuously improving asset management practices. 1.3 Close alignment with corporate vision and strategy. 1.4 That asset management is driven by clearly defined strategies, business objectives and service level targets. 1.5 That responsibilities and accountabilities for asset management are clearly assigned. 1.6 An emphasis on knowledge of what assets are owned and why, the location of the assets and the condition of the assets. 1.7 An emphasis on optimising asset utilisation and performance. 1.8 That a total life cycle approach should be taken to asset management. 1.9 That the use of 'non-network' solutions and demand management techniques as alternatives to asset acquisition is considered.	The asset management approach is aligned to the Company's vision and strategy. This is summarised in *Sections 1 and 2* of the AMP Summary Document and these sections explain Firstgas corporate objectives, purpose of the AMP in meeting those objectives and governance over asset management decisions. The asset management improvement programme is detailed in *Sections 2, 3 and 4*. In *Section 3* a diagram provides an overview of the asset management framework displaying the line of sight from the strategic plan through to the asset management system and life cycle delivery. Key Performance Indicators (KPIs) are included in *Section 3.* For more detail, *Appendix H* describes the asset management approach and: • outlines the asset management approach and the performance measures for the network, including targets. • performance measures and AMMAT results, along with providing details about the approach to continuous improvement and defining several improvement initiatives. • corporate objectives, and the purpose of the AMP in meeting those objectives. • defines service level targets. • defines accountabilities for the asset management plan and asset management governance. • optimisation of asset performance. • total lifecycle management approach.

	• the considerations for deferring asset purchase or renewal/replacement. As part of asset management, Firstgas understands the assets owned, their location and condition. In the AMP the following appendices are provided: • An overview of the network configuration and fleet, including fleet condition, *Appendix C*. • Further information on asset condition, including age, and configuration are included in *Appendix D* (asset details) • *Appendix E* (system schematics).
2. The disclosure requirements are designed to produce AMPs that are based on, but are not limited to: 2.1 the core elements of asset management identified in clause 1.	2.1 The elements identified in clause 1 are described above.
2.2 are clearly documented and made available to all stakeholders.	2.2 The AMP is distributed to major stakeholders and made publicly available on the Firstgas website (www.firstgas.co.nz). The AMP is formatted for stakeholders to focus on the level of detail that is useful to them (e.g. the AMP Summary Document or the more detailed appendices).
2.3 Contain sufficient information to allow interested persons to make an informed judgement about the extent to which the GTB's asset management processes meet best practice criteria and outcomes are consistent with outcomes produced in competitive markets.	2.3 The Company's asset management practices and self-assessment against the AMMAT principles are described in *Section 2.4 – Asset Management Approach*. Further details are provided in *Appendix H - Section H3 Asset Management System*.
2.4 Specifically support the achievement of disclosed service level targets.	2.4 Performance measures and target levels are defined in *Appendix H*.
2.5 Emphasise knowledge of the performance and risks of assets and identify opportunities to improve performance and provide a sound basis for ongoing risk assessment.	2.5 The Company's approach to risk management is included in *Section 2 and 4* of the AMP Summary Document. A more detailed representation of the approach to risk management is found in *Appendix H. Appendix C* considers risks more specifically focussed on Assets along with opportunities and projects related to performance improvements.
2.6 Consider the mechanics of delivery including resourcing.	2.6 Planning and scheduling is part of the asset management framework and system, as described in *Section 1* of the AMP Summary Document. A key part of this is ensuring the required resources are available to deliver on the asset management plans and objectives. The delivery model, including consideration of resourcing, is included in *Appendix H – Section H3.7 Delivery Model*.
2.7 Consider the organisational structure and capability necessary to deliver the AMP.	2.7 The organisational structure in relation to the delivery and responsibilities of the AMP are included in the AMP Summary Document - *Section 1 - Purpose of the Transmission AMP*. Refer *Appendix H – Section H3.7 Delivery Model* for more detail.
2.8 Consider the organisational and contractor competencies and any training requirements.	2.8 *Appendix H – Section H3.3 - Competency and Training* outlines competency and training requirements.
2.9 Consider the systems, integration and information management necessary to deliver the plans.	2.9 Asset management systems, integration and information management are outlined in the AMP Summary Document - *Section 3.2 – Asset Management Approach*, and in greater detail in *Appendix H - Section H3 - Asset Management System*.
2.10 To the extent practical, use unambiguous and consistent definitions of asset management processes and terminology consistent with the terms used in this attachment to enhance comparability of asset management practices over time and between GTBs.	2.10 Throughout the AMP terminology and definitions have been used that are consistent with those used in *Attachment A: Asset Management Plans* of the information disclosure determination and other disclosure documentation. Definitions of less common terms are included in *Appendix A – Glossary* and in the AMP Summary Document to assist understanding of the terminology used in the AMP.
2.11 Promote continual improvements to asset management practices.	2.11 The AMMAT results are detailed in *Section 3.2* of the AMP Summary Document. *Appendix H – H.1 - Asset Management Improvements* describes the approach to continuous improvement.
Section Contents of the AMP	
3. The AMP must include the following: 3.1 A summary that provides a brief overview of the contents and highlights information that the GTB considers significant.	The AMP Summary Document provides an overview of the: • scope and structure of the AMP including the document appendices • key messages and themes • The asset management framework and systems, and planned improvements in these areas • A regional dashboard (in map format) indicating the line of sight between asset health and expenditure • Capex & Opex forecasts and key projects.
3.2 Details of the background and objectives of the GTB's asset management and planning processes.	The asset management framework and policy are described in the AMP Summary Document - *Section 3.2 - Asset Management Approach*. *Appendix H* outlines the asset management background, objectives and planning processes.
3.3 A purpose statement which: 3.3.1 makes clear the purpose and status of the AMP in the GTB's asset management practices. The purpose statement must	*Section 1* of the AMP Summary Document outlines the statement of purpose of the AMP and the corporate focus for asset management. *Section 2* provides an illustrative overview of the asset management framework

also include a statement of the objectives of the asset management and planning processes. 3.3.2 states the corporate mission or vision as it relates to asset management. 3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the GTB. 3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management. 3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans.	showing how the asset management system, including the asset management plan, feeds into, and out of, the Firstgas strategic plan. The asset management policy and framework are outlined in *Appendix H – H.2 - Asset Management Framework*. This appendix links the corporate vision and mission to the asset management approach and also describes how the different asset management plans and documentation relate to each other.
3.4 Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed.	The AMP Summary Document identifies the 10-year period covered by the AMP. This is defined as the "planning period".
3.5 The date that it was approved by the directors.	The date this AMP was approved by directors is included in *Section 1* of the AMP Summary Document and on the Directors' certificate in *Appendix N.*
3.6 A description of each of the legislative requirements directly affecting management of the assets, and details of: 3.6.1 how the GTB meets the requirements. 3.6.2 the impact on asset management.	*Appendix H* identifies where applicable legislations, regulations, and industry codes that affect the management of assets and describes how these requirements are incorporated into asset management.
3.7 A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates: 3.7.1 how the interests of stakeholders are identified. 3.7.2 what these interests are. 3.7.3 how these interests are accommodated in asset management practices. 3.7.4 how conflicting interests are managed.	The AMP Summary Document - *Section 9 – Stakeholder Engagement* describes how the needs and interests of all stakeholders are identified, and how conflicting interests are managed. The diagram of the asset management system in Section 3 illustrates how asset management policies, strategies and objectives reflect stakeholder requirements. *Appendix H* provides greater detail on stakeholder interests and describes how: (1) stakeholder requirements are identified. (2) the interests of each of the key stakeholders are identified. (3) stakeholder interests are included in the decision making and asset management practices.
3.8 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including:	The AMP Summary Document - *Section 2 Overview of Firstgas* describes the Firstgas corporate and organisational structure.
3.8.1 governance - a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors. 3.8.2 executive - an indication of how the in-house asset management and planning organisation is structured. 3.8.3 field operations - an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used.	In greater detail, *Appendix H- H.3.2 Asset Management Plan* and *H.3.7 Delivery Model* describes: • Asset Management Governance and organisational structure. • the field operations delivery model and management of field operations.
3.9 All significant assumptions. 3.9.1 quantified where possible. 3.9.2 clearly identified in a manner that makes their significance understandable to interested persons and including: • a description of changes proposed where the information is not based on the GTB's existing business. • the sources of uncertainty and the potential effect of the uncertainty on the prospective information. • the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Forecast on Operational Expenditure set out in Schedule 11b.	Key assumptions for the development of the AMP are outlined in *Appendix H- H3.2 Key Assumptions*. Expenditure assumptions are outlined in *Appendix J - Expenditure Overview*. • There are no changes proposed in this AMP where the information is not based on current business. • The AMP Summary Document - *Section 3.2.1 Managing Firstgas Assets through Uncertainty* and *Appendix H – H.3.1 Asset Management Strategy* identifies in more detail, any sources of uncertainty and possible effects and describes methods of managing these uncertainties, including the future of gas in New Zealand. • Escalation rates utilised for the purposes of disclosing nominal expenditure are included in *Appendix J - Expenditure Overview*.
3.10 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures.	The AMP Summary Document - *Section 7 The Year Ahead* includes areas of focus for the coming year. Any factors that may lead to a material difference between prospective information and the corresponding actual information recorded in future disclosures are also covered in this section. The AMP Summary Document - *Section 3.2.1 Managing Firstgas Assets through Uncertainty* and *Appendix H – H.3.1 Asset Management Strategy* identifies in more detail, any sources of uncertainty and possible effects and describes methods of managing these uncertainties, including the future of gas in New Zealand.

3.11 An overview of asset management strategy and delivery. To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify – 1 how the asset management strategy is consistent with the GTB's other strategy and policies. 2 how the asset strategy considers the life cycle of the assets. 3 the link between the asset management strategy and the AMP. 4 processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.	The AMP Summary Document - *Section 3.2 Asset Management Approach* describes the approach along with asset management improvement programmes. These sections provide an overview of the asset management strategy including how it aligns with corporate strategy, links with the AMP and life cycle of assets. *Appendix H* describes in detail: (1) the Asset Management Framework and Policy and describes how the framework relates to corporate objectives. (2) how the Asset Management Framework includes asset lifecycle management. (3) the relationship between the Asset Management Framework / strategy and the Asset Management Plan. (4) the financial authority and control, risk management and performance measures and targets. Processes to support the framework and governance described above are detailed throughout the AMP document.
3.12 An overview of systems and information management data. To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe – 1 the processes used to identify asset management data requirements that cover the whole of life cycle of the assets. 2 the systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets. 3 the systems and controls to ensure the quality and accuracy of asset management information. 4 the extent to which these systems, processes and controls are integrated.	The AMP Summary Document *Sections 2, 3 and 4* include asset management programmes and past year/future year activities that support the AMMAT disclosure in *Appendix B – Information Disclosure Schedules – Schedule 13*. The AMP Summary Document - *Section 3.1 – Asset Categories* and *Appendix H – H.3.12 Information and Data* provides a view of systems and information data supporting the AMMAT disclosure and more specifically the following; (1) defines the categorisation and relationships of asset management data and the related systems used to manage the lifecycle of Firstgas assets. (2) identifies the systems used to manage asset data, including the condition and capacity of assets, and asset performance. (3) outlines asset data quality management processes, (4) and system integration.
3.13 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data. Discussion of the limitations of asset management data is intended to enhance the transparency of the AMP and identify gaps in the asset management system.	The AMP Summary Document - *Section 6.3 Asset Management Improvement Programme* and *Appendix H* identifies data limitations and initiatives to improve data quality.

3.14 A description of the processes used within the GTB for: 3.14.1 managing routine asset inspections and network maintenance. 3.14.2 planning and implementing network development projects. 3.14.3 measuring network performance.	The detail of the underlying processes are included in *Appendix H - Asset Management Approach* and *Appendix F - System Development. Appendix H* describes: • maintenance approach and processes • provides detail on development planning • describes the network performance measures and targets. *Appendix F* describes the system development process.
3.15 An overview of asset management documentation, controls and review processes. To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should: 1 identify the documentation that describes the key components of the asset management system and the links between the key components. 2 describe the processes developed around documentation, control and review of key components of the asset management system. 3 where the GTB outsources components of the asset management system, the processes and controls that the GTB uses to ensure efficient and cost-effective delivery of its asset management strategy. 4 where the GDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house. 5 audit or review procedures undertaken in respect of the asset management system.	*Section 3* of the AMP Summary Document describes the approach to asset management. *Appendix H – Sections H.3.3 Competency and Training, H.3.5 Asset Lifecyle Management, H.4.1 Business Support Expenditure* describe the key components of the asset management system including documentation, controls and the review process including; (1) The documentation describing the key components of the asset management system. (2) Structure and financial control. (3) Systems and process for retaining asset knowledge.

3.16 An overview of communication and participation processes. To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should: 1 communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants. 2 demonstrate staff engagement in the efficient and cost-effective delivery of the asset management requirements.	*Section 6* of the AMP Summary Document outlines communication with key stakeholders on aspects of the AMP. *Appendix H* outlines the following: (1) communication with key stakeholders on aspects of the AMP. (2) staff engagement in the preparation of the AMP. Where applicable, throughout the AMP key internal stakeholder teams are referenced in relation to delivery of the asset management requirements.
4 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise.	All expenditure figures are denominated in constant value terms using FY2023 New Zealand dollars as stated in *Appendix J - Expenditure Overview*.
5 The AMP must be structured and presented in a way that the GTB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	The AMP has been structured and presented in a manner intended to simplify the presentation of information relevant to the disclosure. The AMP Summary Document can be read as a standalone document to provide a summarised view of the asset management plans including the development of the asset management strategy and implementation of an asset health and criticality approach to asset management. The appendices provide greater detail on the plans at an asset fleet level, the approach to asset management, and the systems and personnel to ensure the plans can be delivered.
Section Assets Covered	
6 The AMP must provide details of the assets covered, including: 6.1 A map and high-level description of the areas covered by the GTB, including the region(s) covered.	A map of the high-pressure transmission pipelines is provided in the AMP Summary Document – *Section 3 – The Gas Transmission Network*.
6.2 A diagram, with any cross-referenced information contained in an accompanying schedule, of each transmission system of the pipeline owner showing the following details: 6.2.1 all assets in the system with notations showing: (a) internal, external, or nominal pipe diameters used (identifying whether internal, external, or nominal pipe diameters are used). (b) pipe design pressure ratings. (c all stations, main-line valves, intake points and offtake points, including a unique identifier for each item. (d the distance between the items referred to in subclause 6.2.1(c) of this attachment.	*Appendix E - System Schematics* provides regional schematics of the transmission network showing the detailed assets. *Appendix D - Asset Details* lists the asset types within the transmission system. This appendix includes details relevant to the asset types including diameters and pressure ratings. Distance between station explained in *Appendix E - System Schematics*.
6.2.2 if applicable, the points where a significant change has occurred since the previous disclosure of the information referred to in clause 6.2.1 of this attachment, including: (a) a clear description of every point on the network that is affected by the change. (b) a statement as to whether the capacity of the network, at the points where the change has occurred, or other points (as the case may be) has increased or decreased or is not affected. (c) a description of the change.	There have been no significant network changes since previous disclosure.
6.3 The AMP must describe the network assets by providing the following information for each asset category. 6.4 Description and quantity of assets.	*Appendix C – C1.2 Key Statistics* includes an overview and quantity of each asset category.
6.5 Age profiles.	*Appendix C* displays age profiles and condition of assets within each asset category.
6.6 A discussion of the condition of the assets, further broken down into more detailed categories as appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	The AMP Summary Document – *Section 3.2.6 Geohazard Management* details geohazards on the network that may impact when assets are scheduled for replacement and *Section 4* lists the replacement projects planned in the coming year. *Appendix C* provides detail on the condition of the assets, along with risks and issues associated with assets and key projects. *Appendix B* includes information on the condition or core assets, graded from 1 (needing replacement soon) to 4 (in good condition). Refer Schedule 12a.
7. The asset categories discussed in clause 6.3 of this attachment should include at least the following: 7.1 the categories listed in the Report on Forecast Capital Expenditure in Schedule 11a(iii). 7.2 assets owned by the GTB but installed at facilities owned by others.	The asset categories in *Appendix C* are the same categories listed in the Report on Forecast Capital Expenditure in schedule 11a (refer *Appendix B*).

Section Transmission system capacity	
8. The AMP must include an assessment of the extent to which physical pipeline capacity is adequate to address the current and anticipated future needs of consumers, considering expected demands on the transmission system and the GTB's investment plans.	System capacity and development planning is documented in the following appendices; • *Appendix F –System Development* • *Appendix G – Security Standard* • *Appendix I – System Capacity Determination*.
8.1 The assessment must include the following: 8.1.1 Subject to clauses 8.2, 8.3 and 8.4 of this attachment, for each offtake point with a throughput of gas during the system peak flow period of 2,000 GJ or more, an analysis of available capacity, including a description of any potential transmission system constraints. 8.1.2 a description of the extent to which the GTB's planned investments will affect the constraints identified in clause 8.1.1 of this attachment. 8.1.3 a description of the extent to which constraints identified in clause 8.1.1 of this attachment are impacting upon the quality of service provided to existing consumers.	A detailed gate station / off-take capacity analysis is provided in *Appendix F – System Development – F.2.4 Station Capacity Upgrades*
8.2 The analysis of available capacity disclosed pursuant to clause 8.1.1 of this attachment for each offtake point must separately assume that the throughput of gas at the other offtake points on the transmission system. 8.2.1 occurred during a recent system peak flow period. 8.2.2 maintain observed trends, e.g. growth trends, peak demand factors and trendline adjustments, or other modelled behaviours.	Station modelling principles and results are identified in *Appendix I – System Capacity Determination*
8.3 For the purposes of clause 8.1.1 of this attachment, the AMP: 8.3.1 may treat offtake points that are supplied from a common physical connection to a pipeline as a single offtake point, provided that this is noted in the AMP. 8.3.2 must describe the modelling methodology and include all material assumptions, including peak flow period throughputs not contributing to capacity constraints (e.g. interruptible flows). physical boundaries of the transmission system. sources of data used. modelled representation of the transmission systems and its operational constraints. 8.3.3 must identify the recent system peak flow periods used in the clause 8.2.1 analysis and must either set out the peak flow information specified in subclauses 2.5.2(1)(a) and 2.5.2(1)(b) of this determination or provide reference to a website at which interested persons can readily access the same information at no charge as specified in subclause 2.5.2(4) of this determination. 8.3.4 must include the name, version and source of any commercial computer software used to simulate the transmission system.	Capacity and the modelling methodology used to determine capacity is in included in *Appendix I – System Capacity Determination*. This includes naming any software used for the modelling. Recent system peak flows are published on the website: www.firstgas.co.nz.
8.4 If the analysis specified in clause 8.1.1 of this attachment is posted on a website normally used by the GTB for the publication of information and can be readily accessed at no charge by interested persons, the analysis may be incorporated in the AMP by reference subject to the information being retained on such a website for a period of not less than five years.	The AMP is posted on the Firstgas website: www.firstgas.co.nz

Section Service Levels	
9. The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	The AMP Summary Document - *Section 6.4 Performance of the Transmission System* describes key performance indicators, results for 2022 and target for coming year. *Appendix H* provides detail and information on the full suite of performance measures and quantified targets and how they are consistent with the asset management objectives.
10. Performance indicators for which targets have been defined in Clause 9 must include the DPP requirements required under the price quality path determination applying to the regulatory assessment period in which the next disclosure year falls. Performance indicators for which targets have been defined in Clause 9 should also include: 1. consumer-oriented indicators that preferably differentiate between different consumer groups. 2. indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	*Appendix H* provides further detail and information on the full suite of performance measures and quantified targets, including: • Quality standards specified under the price quality path. • consumer-oriented performance measures. • measures of asset performance and delivery.
11. The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	*Appendix H* describes the basis for each performance target.
12. Targets should be compared to historic values where available to provide context and scale to the reader.	The AMP Summary Document - *Section 6.4 Performance of the Transmission System* includes a table of key performance indicators and trend. Firstgas has only operated the gas networks since 2016 and historic comparatives are limited to commencement of ownership. Historical performance values dated back to this year are included in *Appendix H* in order to provide context to the reader.
13. Where forecast expenditure is expected to materially affect performance against a target defined in clause 9, the target should be consistent with the expected change in the level of performance. Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.	Forecast expenditure is not expected to materially affect performance against any performance targets.
14 AMPs must provide a detailed description of network development plans, including:	Network development plans are described in *Appendix F –System Development* and *Appendix I – System Capacity Determination*
14.1 A description of the planning criteria and assumptions for network development. Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated, and the methodology briefly described.	The AMP Summary Document – *Section 4 The Year Ahead* includes significant activities planned for the 2024 disclosure year. Development planning criteria and methodology are detailed in *Appendix I – System Capacity Determination.*
14.2 A description of strategies or processes (if any) used by the GTB that promote cost efficiency including through the use of standardised assets and designs. The use of standardised designs may lead to improved cost efficiencies. This section should discuss: 1 the categories of assets and designs that are standardised. 2 the approach used to identify standard designs.	*Appendix H – H.3.5.3 Lifecycle Management Strategy* includes commentary around the use of standardised designs within the system.
14.3 A description of the criteria used to determine the capacity of new equipment for different types of assets or different parts of the network. The criteria described should relate to the GTB's philosophy in managing planning risks.	Capacity modelling methods are outlined in *Appendix I – System Capacity Determination.*
14.4 A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision. 14.4.1 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand. 14.4.2 Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates. 14.4.3 Provide separate forecasts to at least off-take points covering at least a minimum 5-year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are considered in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts. 14.4.4 Identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period.	The AMP Summary Document - *Section 6.3 - Asset Management Improvement Programme* provides an overview of how all projects approved under the asset management system align with the Company's goals and vision. Further information on load is available in *Appendix I – System Capacity Determination* including: • Load forecasting methods I. Constraints within the system are documented in *Appendix H – H.3.12 ICT Investments* project prioritisation and link back to the corporate investment prioritisation criteria.

14.5 Analysis of the significant network level development options identified, and details of the decisions made to satisfy and meet target levels of service, including: 14.5.1 the reasons for choosing a selected option for projects where decisions have been made. 14.5.2 the alternative options considered for projects that are planned to start in the next five years. 14.5.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	The AMP Summary Document – *Section 7 - The Year Ahead* details the significant projects for the coming year. For more information on network development see *Appendix I*.
14.6 A description and identification of the network development programme and actions to be taken, including associated expenditure projections. The network development plan must include: 14.6.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months. 14.6.2 a summary description of the programmes and projects planned for the following four years (where known). 14.6.3 an overview of the material projects being considered for the remainder of the AMP planning period. For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next 5 years, alternative options should be discussed.	The AMP Summary Document – *Section 7 - The Year Ahead* describes the significant activities planned for FY2024. Many of these activities or programmes of work, extend beyond a single year. A summary of total Capex expenditure is included in the AMP Summary Document – *Section 8 - Expenditure Forecast*. *Appendix F –System Development* and *Appendix I – System Capacity Determination* describe the development projects forecast for the planning period. Associated expenditure projections for network development are included in *Appendix J - Expenditure Overview*.
14.7 A description of the extent to which the disclosed network development plans meet the loads anticipated in current gas demand forecasts prepared by the Gas Industry Company or any Government department or agency.	*Appendix I – System Capacity* covers demand forecasts.
Section Lifecycle Asset Management Planning (Maintenance and Renewal)	
15. The AMP must provide a detailed description of the lifecycle asset management processes, including: 15.1 The key drivers for maintenance planning and assumptions.	The asset management system as illustrated in *Section 3* of the AMP Summary Document shows the line of sight from stakeholders and strategic plan through to life-cycle asset management. Life-cycle management includes maintenance decision. *Section 4* of the AMP Summary Document further illustrates the line of sight between asset health and criticality and capex and opex expenditure. *Section 4* highlights the roll out of a maintenance optimisation programme planned for this year. The key drivers for the asset maintenance are described in *Appendix H* and *Appendix K – Scheduled Maintenance*.
15.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include: 15.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done. 15.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems. 15.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period.	The AMP Summary Document – *Section 8 - Expenditure Forecast* includes the budget for total Opex over the planning period. *Appendix K – Scheduled Maintenance* provides further detailed information on: • Routine inspections and maintenance. • Key risks and issues identified for each categorised asset type's budget for maintenance activities.
15.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include: 15.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based. 15.3.2 a description of the projects currently underway or planned for the next 12 months. 15.3.3 a summary of the projects planned for the following four years (where known). 15.3.4 an overview of other work being considered for the remainder of the AMP planning period.	The AMP Summary Document – *Section 3.2 - Asset Management Approach* highlight a view of asset health leading to investment decisions (whether replacement or renewal). Key asset replacement projects undertaken in FY2023 are included in *Section 3* and key projects for the coming year are described in *Section 7* of the AMP Summary Document. The approach to asset replacement and renewal, and the investment drivers are described in *Appendix H*. Further detail on projects planned for the 10-year planning period are included in *Appendix C*.

Non-Network Development, Maintenance and Renewal)		
16.	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including:	The AMP Summary Document – *Section 3.2 - Asset Management Approach* describes the asset management framework and system. The same approach to life cycle management and line of sight from the strategic plan to the asset management system applies to both network and non-network assets.
16.1	a description of non-network assets.	Non-network assets are described in *Appendix H*.
16.2	development, maintenance and renewal policies that cover them.	Non-network assets are described in *Appendix H*.
16.3	a description of material capital expenditure projects (where known) planned for the next five years.	Non-network asset projects are described in *Appendix H*.
16.4	a description of material maintenance and renewal projects (where known) planned for the next five years.	Non-network asset projects are described in *Appendix H*.
Risk Management		
17	AMPs must provide details of risk policies, assessment, and mitigation, including:	The AMP Summary Document – *Section* provides information on risk management for the transmission system. *Appendix H – Section H.3.4 - Risk and Review* describes asset risk management policy, principles and framework, as well as key risk sources.
17.1	methods, details and conclusions of risk analysis.	The Risk Management Framework and identified general risks are defined in Section 2 of the AMP Summary Document and in *Appendix H- Section H.3.4 - Risk and Review*. Further detail on asset related risks are outlined within each asset section of *Appendix C*.
17.2	strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events.	The AMP Summary Document – *Section 2* considers how Firstgas addresses risks on the transmission system. *Appendix H - Section H.3.4 - Risk and Review* outlines various risk sources, with factors and strategies used to identify vulnerable areas.
17.3	a description of the policies to mitigate or manage the risks of events identified in clause 17.2 of this attachment.	The AMP Summary Document – *Section 2* considers how Firstgas manages risks on the network. *Appendix H - Section H.3.4 - Risk and Review* identifies the policy and processes used to evaluate and treat risks associated with the network.
18	Details of emergency response and contingency plans. Asset risk management forms a component of a GTB's overall risk management plan or policy, focusing on the risks to assets and maintaining service levels. AMPs should demonstrate how the GTB identifies and assesses asset related risks and describe the main risks within the network. The focus should be on credible low-probability, high-impact risks. Risk evaluation may highlight the need for specific development projects or maintenance programmes. Where this is the case, the resulting projects or actions should be discussed, linking back to the development plan or maintenance programme.	*Appendix H - Section H.3.4* outlines the emergency response and contingency plans.

Evaluation of performance	
19. AMPs must provide details of performance measurement, evaluation, and improvement, including:	Performance measures are included in *Section 3* of the AMP Summary Document. Details of performance measurement, evaluation and improvement are outlined in *Appendix H*
19.1 A review of progress against plan, both physical and financial. 1 Referring to the most recent disclosures made under section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances. 2 Commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced. 3 Commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.	The AMP Summary Document - *Section 6.4 - Performance of the Transmission System* reviews the progress against plan for the prior year. Further detail on the progress of development projects and maintenance initiatives / programmes is available in *Appendix H*.
19.2 An evaluation and comparison of actual service level performance against targeted performance. In particular, comparing the actual and target service level performance for all the targets discussed under the 'service levels' section of the AMP over the previous 5 years and explain any significant variances.	The comparison of actual service level performance against targeted performance is included in The AMP Summary Document - *Section 6.4 - Performance of the Transmission System* and in *Appendix H – Section H.5 - Performance Measures*. Historical information for the time Firstgas has owned the transmission network is included for the key performance metrics in *Appendix H – Section H.5 - Performance Measures*.
19.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the GTB's asset management and planning processes.	*Section 4* of the AMP Summary Document includes the AMMAT gap analysis and how it is used to inform the asset management improvement programme. Evaluation of AMMAT results, and future improvement initiatives are found in *Appendix H – Section H.1 - Asset Management Improvements*.
19.4 An analysis of gaps identified in clauses 19.2 and 19.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	Section 4 of the AMP Summary Document includes the AMMAT gap analysis and how it is used to inform the asset management improvement programme. Improvement initiatives based on gaps in the AMMAT results are included in *Appendix H – Section H.1 - Asset Management Improvements*.
20. AMPs must describe the processes used by the GTB to ensure that: 20.1 The AMP is realistic, and the objectives set out in the plan can be achieved.	The AMP Summary Document – *Section 3.2 - Asset Management Approach* sets a line of sight between the corporate strategy and life cycle management. This, alongside the governance and organisation structure outlined in Section 2, ensures the AMP is realistic and the objectives are achievable. *Appendix H – Section H - Asset Management* describes in greater detail the governance and framework to achieve a realistic AMP.
20.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	The AMP Summary Document – *Section 2 - Overview of Firstgas* describes in general the governance and framework of the AMP, as well as the organisational structure that supports the implementation of the AMP. *Appendix H – Section H - Asset Management* describes the governance and framework of the AMP.

Appendix N Director's Certificate

Certification for Year-beginning Disclosures

Clause 2.9.1

We, Mark Adrian Ratcliffe and Fiona Ann Oliver, being directors of First Gas Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of First Gas Limited prepared for the purposes of clauses 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the *Gas Transmission Information Disclosure Determination 2012* in all material respects complies with that determination;

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards; and

c) The forecasts in Schedules 11a, 11b, 12a and 12b are based on objective and reasonable assumptions which both align with First Gas Limited's corporate vision and strategy and are documented in retained records.

Director: Mark Adrian Ratcliffe

27 July 2023
Date

Director: Fiona Ann Oliver

27 July 2023
Date