Firstgas

GAS TRANSMISSION

Asset Management Plan 2020

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.

TERM	DEFINITION
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.
CRM	Customer Relationship Management – Approach to manage the company's interaction with current and potential customers.
DCVG	Direct Current Voltage Gradient – A survey technique used for assessing the effectiveness of corrosion protection on buried steel structures.
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.
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 of physical assets to maximize their use; save money; improve quality and efficiency; and safeguard health, safety and the environment.

TERM	DEFINITION
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.

TERM	DEFINITION
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.
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.

TERM	DEFINITION
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.
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.

TERM	DEFINITION
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.

TERM	DEFINITION
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.
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.

APPENDIX B: INFORMATION DISCLOSURE SCHEDULES

This appendix includes the following Information Disclosure Schedules:

Schedule 11a – Report on Forecast Capital Expenditure

Schedule 11b – Report on Forecast Operational Expenditure

Schedule 12a – Report on Asset Condition

Schedule 12b – Report on Forecast Demand

Schedule 13 – Report on AMMAT

Schedule 14a – Commentary on Escalation

B.1: Schedule 11a: Forecast Capex

Company Name	**First Gas Limited (Transmission)**
AMP Planning Period	**1 October 2020 – 30 September 2030**

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 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**
9		**11a(i): Expenditure on Assets Forecast**	**$000 (nominal dollars)**										
10		Consumer connection	1,096	1,530	1,561	2,122	2,165	2,208	2,252	2,297	2,343	2,390	2,438
11		System growth	156	1,632	5,306	1,698	1,732	1,767	1,802	1,838	1,875	1,912	1,950
12		Asset replacement and renewal	27,753	23,321	33,713	31,788	30,279	34,923	34,511	37,170	38,808	41,974	37,938
13		Asset relocations	1,586	2,856	2,081	2,122	2,165	2,208	2,252	2,297	2,343	2,390	2,438
14		Reliability, safety and environment:											
15		Quality of supply											
16		Legislative and regulatory											
17		Other Reliability, Safety and Environment		510	520	531	541	552	563	574	586	598	609
18		**Total reliability, safety and environment**	-	510	520	531	541	552	563	574	586	598	609
19		**Expenditure on network assets**	30,591	29,849	43,181	38,261	36,882	41,658	41,380	44,176	45,955	49,264	45,373
20		Expenditure on non-network assets	7,916	17,384	5,541	5,211	6,110	5,242	4,766	8,597	16,169	8,104	7,425
21		**Expenditure on assets**	38,507	47,233	48,722	43,472	42,992	46,900	46,146	52,773	62,124	57,368	52,798
22													
23	*plus*	Cost of financing	329	396	358	371	367	401	394	451	531	490	451
24	*less*	Value of capital contributions	1,428	1,836	1,873	1,910	1,948	1,987	2,027	2,068	2,109	2,151	2,194
25	*plus*	Value of vested assets											
26		**Capital expenditure forecast**	37,408	45,793	47,207	41,933	41,411	45,314	44,513	51,156	60,546	55,707	51,055
27													
28		Assets commissioned	31,134	37,530	33,926	35,149	34,761	37,920	37,311	42,670	50,230	46,384	42,690
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 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**
32			**$000 (in constant prices)**										
33		Consumer connection	1,096	1,500	1,500	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
34		System growth	156	1,600	5,100	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
35		Asset replacement and renewal	27,753	22,863	32,404	29,954	27,973	31,631	30,645	32,358	33,122	35,122	31,122
36		Asset relocations	1,586	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
37		Reliability, safety and environment:											
38		Quality of supply	-	-	-	-	-	-					
39		Legislative and regulatory	-	-	-	-	-	-					
40		Other Reliability, Safety and Environment	-	500	500	500	500	500	500	500	500	500	500
41		**Total reliability, safety and environment**	-	500	500	500	500	500	500	500	500	500	500
42		**Expenditure on network assets**	30,591	28,463	41,504	36,054	34,073	37,731	36,745	38,458	39,222	41,222	37,222
43		Expenditure on non-network assets	7,916	17,043	5,326	4,911	5,645	4,749	4,232	7,484	13,800	6,781	6,091
44		**Expenditure on assets**	38,507	45,506	46,830	40,965	39,718	42,480	40,977	45,942	53,022	48,003	43,313
45		**Subcomponents of expenditure on assets (where known)**											
46		Research and development											

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	30 Sep 20	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27	30 Sep 28	30 Sep 29	30 Sep 30
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	30	61	122	165	208	252	297	343	390	438
System growth	-	32	206	98	132	167	202	238	275	312	350
Asset replacement and renewal	0	458	1,309	1,834	2,306	3,292	3,866	4,812	5,686	6,852	6,816
Asset relocations	-	856	81	122	165	208	252	297	343	390	438
Reliability, safety and environment:											
Quality of supply	-	-	-	-	-	-	-	-	-	-	-
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other Reliability, Safety and Environment	-	10	20	31	41	52	63	74	86	98	109
Total reliability, safety and environment	-	10	20	31	41	52	63	74	86	98	109
Expenditure on network assets	0	1,386	1,677	2,207	2,809	3,927	4,635	5,718	6,733	8,042	8,151
Expenditure on non-network assets	-	341	215	300	465	493	534	1,113	2,369	1,323	1,334
Expenditure on assets	0	1,727	1,892	2,507	3,274	4,420	5,169	6,831	9,102	9,365	9,485

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	30 Sep 20	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25
*Consumer types defined by GTB**	**$000 (in constant prices)**					
Forecast Provision	1,096	1,500	1,500	2,000	2,000	2,000
**include additional rows if needed*						
Consumer connection expenditure	1,096	1,500	1,500	2,000	2,000	2,000
less Capital contributions funding consumer connection						
Consumer connection less capital contributions	1,096	1,500	1,500	2,000	2,000	2,000

11a(iii): System Growth

	30 Sep 20	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25
Pipes	-	1,000	4,100	-	-	-
Compressor stations	-	-	-	-	-	-
Other stations	156	600	1,000	1,600	1,600	1,600
SCADA and communications	-	-	-	-	-	-
Special crossings	-	-	-	-	-	-
System growth expenditure	156	1,600	5,100	1,600	1,600	1,600
less Capital contributions funding system growth						
System growth less capital contributions	156	1,600	5,100	1,600	1,600	1,600

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	30 Sep 20	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25
	$000 (in constant prices)					
Pipes	11,799	14,215	11,602	14,199	12,381	12,231
Compressor stations	4,375	2,500	12,500	11,500	8,580	12,580
Other stations	6,065	4,500	5,000	1,736	4,194	2,694
SCADA and communications	30	106	221	534	950	2,525
Special crossings	20	44	88	44	44	44
Components of stations (where known)						
Main-line valves	307	300	697	612	612	391
Heating system	3,553	474	1,620	385	385	385
Odorisation plants	764	21	89	89	89	89
Coalescers	-	-	88	-	-	88
Metering system	680	400	250	689	439	439
Cathodic protection	32	224	248	87	172	87
Chromatographs	128	79	-	79	128	79
Asset replacement and renewal expenditure	27,753	22,863	32,404	29,954	27,973	31,631
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	27,753	22,863	32,404	29,954	27,973	31,631

11a(v): Asset Relocations

Project or programme*	30 Sep 20	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25
Forecast Provision	1,586	2,000	2,000	2,000	2,000	2,000
**include additional rows if needed*						
All other projects or programmes - asset relocations						
Asset relocations expenditure	1,586	2,000	2,000	2,000	2,000	2,000
less Capital contributions funding asset relocations						
Asset Relocations less capital contributions	1,586	2,000	2,000	2,000	2,000	2,000

11a(vi): Quality of Supply

Project or programme*	30 Sep 20	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25
Category not used						
**include additional rows if needed*						
All other projects or programmes - quality of supply						
Quality of supply expenditure	-	-	-	-	-	-
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	-	-	-	-	-	-

11a(vii): Legislative and Regulatory

Project or programme*						
Category not used						
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

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

for year ended	*Current Year CY* **30 Sep 20**	*CY+1* **30 Sep 21**	*CY+2* **30 Sep 22**	*CY+3* **30 Sep 23**	*CY+4* **30 Sep 24**	*CY+5* **30 Sep 25**
Project or programme*	**$000 (in constant prices)**					
Forecast Provision	-	500	500	500	500	500
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment total	-	500	500	500	500	500
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	-	500	500	500	500	500

11a(ix): Non-Network Assets

Routine expenditure						
Project or programme*	**$000 (in constant prices)**					
ICT	5,524	14,387	4,275	3,679	4,370	3,250
Building refurbishment	1,754	1,464	371	361	404	628
Plant and equipment	300	300	300	300	300	300
Motor vehicle procurement	338	892	380	571	571	571
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	7,916	17,043	5,326	4,911	5,645	4,749
Atypical expenditure						
Project or programme*						
Category not used						
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	7,916	17,043	5,326	4,911	5,645	4,749

B.2: Schedule 11b: Forecast Opex

		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 20	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27	30 Sep 28	30 Sep 29	30 Sep 30
10	**Operational Expenditure Forecast**	$000 (in nominal dollars)										
11	Service interruptions, incidents and emergencies	732	747	762	777	793	809	825	841	858	875	893
12	Routine and corrective maintenance and inspection	14,293	14,581	14,872	15,170	15,473	15,783	16,098	16,420	16,749	17,084	17,425
14	Compressor fuel	5,208	5,313	5,419	5,528	5,638	5,751	5,866	5,983	6,103	6,225	6,349
15	Land management and associated activity	1,541	1,572	1,604	1,636	1,668	1,702	1,736	1,771	1,806	1,842	1,879
16	**Network opex**	21,774	22,213	22,657	23,111	23,572	24,045	24,525	25,015	25,516	26,026	26,546
17	System operations	3,312	3,378	3,446	3,515	3,585	3,657	3,730	3,805	3,881	3,958	4,038
18	Network support	3,807	3,884	3,961	4,041	4,121	4,204	4,288	4,374	4,461	4,550	4,641
19	Business support	15,790	16,107	16,429	16,758	17,093	17,435	17,784	18,139	18,502	18,872	19,250
20	**Non-network opex**	22,909	23,369	23,836	24,314	24,799	25,296	25,802	26,318	26,844	27,380	27,929
21	**Operational expenditure**	44,683	45,582	46,493	47,425	48,371	49,341	50,327	51,333	52,360	53,406	54,475

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 20	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27	30 Sep 28	30 Sep 29	30 Sep 30
24		$000 (in constant prices)										
25	Service interruptions, incidents and emergencies	732	732	732	732	732	732	732	732	732	732	732
26	Routine and corrective maintenance and inspection	14,293	14,293	14,293	14,293	14,293	14,293	14,293	14,293	14,293	14,293	14,293
28	Compressor fuel	5,208	5,208	5,208	5,208	5,208	5,208	5,208	5,208	5,208	5,208	5,208
29	Land management and associated activity	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541
30	**Network opex**	21,774	21,774	21,774	21,774	21,774	21,774	21,774	21,774	21,774	21,774	21,774
31	System operations	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312
32	Network support	3,807	3,807	3,807	3,807	3,807	3,807	3,807	3,807	3,807	3,807	3,807
33	Business support	15,790	15,790	15,790	15,790	15,790	15,790	15,790	15,790	15,790	15,790	15,790
34	**Non-network opex**	22,909	22,909	22,909	22,909	22,909	22,909	22,909	22,909	22,909	22,909	22,909
35	**Operational expenditure**	44,683	44,683	44,683	44,683	44,683	44,683	44,683	44,683	44,683	44,683	44,683

36	**Subcomponents of operational expenditure (where known)**											
37	Research and Development											
38	Insurance											

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 20	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27	30 Sep 28	30 Sep 29	30 Sep 30
41	**Difference between nominal and real forecasts**	$000										
42	Service interruptions, incidents and emergencies	-	15	30	45	61	77	93	109	126	143	161
43	Routine and corrective maintenance and inspection	-	288	579	877	1,180	1,490	1,805	2,127	2,456	2,791	3,132
45	Compressor fuel	-	105	211	320	430	543	658	775	895	1,017	1,141
46	Land management and associated activity	-	31	63	95	127	161	195	230	265	301	338
47	**Network opex**	-	439	883	1,337	1,798	2,271	2,751	3,241	3,742	4,252	4,772
48	System operations	-	66	134	203	273	345	418	493	569	646	726
49	Network support	-	77	154	234	314	397	481	567	654	743	834
50	Business support	-	317	639	968	1,303	1,645	1,994	2,349	2,712	3,082	3,460
51	**Non-network opex**	-	460	927	1,405	1,890	2,387	2,893	3,409	3,935	4,471	5,020
52	**Operational expenditure**	-	899	1,810	2,742	3,688	4,658	5,644	6,650	7,677	8,723	9,792

B.3: Schedule 12a: Asset Condition

Company Name	**First Gas Limited (Transmission)**
AMP Planning Period	**1 October 2020 – 30 September 2030**

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

7				**Asset condition at start of planning period (percentage of units by grade)**						
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	-	1.30%	33.30%	65.40%	-	3	
10	Pipes	Special crossings	km	-	2.00%	40.00%	58.00%	-	3	
11	Stations	Compressor stations	No.	-	-	100.00%	-	-	3	
12	Stations	Offtake point	No.	-	5.17%	93.97%	0.86%	-	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.	-	-	100.00%	-		3	
17	Compressors	Compressors—electric motor driven	No.	-	-	100.00%	-		3	
18	Compressors	Compressors—reciprocating engine driven	No.	22.22%	20.00%	37.78%	20.00%	-	4	22%
19	Main-line valves	Main line valves manually operated	No.	-	10.45%	89.55%	-	-	3	
20	Main-line valves	Main line valves remotely operated	No.	-	-	-	100.00%	-	3	
21	Heating systems	Gas-fired heaters	No.	-	33.65%	37.50%	28.85%	-	3	
22	Heating systems	Electric heaters	No.	-	-	50.00%	50.00%	-	4	
23	Odorisation plants	Odorisation plants	No.	-	17.86%	82.14%	-	-	3	
24	Coalescers	Coalescers	No.	-	-	100.00%	-	-	3	
25	Metering systems	Meters—ultrasonic	No.	16.67%	33.33%	50.00%	-	-	4	
26	Metering systems	Meters—rotary	No.	52.63%	14.04%	33.33%	-	-	4	20%
27	Metering systems	Meters turbine	No.	66.15%	12.31%	16.92%	4.62%	-	4	20%
28	Metering systems	Meters—mass flow	No.	-	-	100.00%	-		3	
29	SCADA and communications	Remote terminal units (RTU)	No.	-	4.76%	74.61%	20.63%	-	3	
30	SCADA and communications	Communications terminals	No.	-	-	-	100.00%	-	4	
31	Cathodic protection	Rectifier units	No.	6.25%	18.75%	56.25%	18.75%	-	3	6%
32	Chromatographs	Chromatographs	No.	11.11%	44.44%	33.33%	11.12%	-	4	11%

B.4: Schedule 12b: Forecast Demand

Company Name	**First Gas Limited (Transmission)**
AMP Planning Period	**1 October 2020 – 30 September 2030**

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

12b(i): Connections

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**
Connection types defined by GTB						
Distribution System	-	-	1	-	1	-
Direct Connect	-	-	1	2	-	1
Bi-directional	-	1	-	-		-
Receipt Point	-	-	-	-	-	-
** include additional rows if needed*						
Connections total	-	1	2	2	1	1

12b(ii): Gas conveyed

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**
Intake volume (TJ)	165,447	162,884	163,198	163,938	164,989	166,175
Quantity of gas delivered (TJ)	164,433	161,850	162,264	163,003	163,953	165,238
Gas used in compressor stations (TJ)	703	703	703	703	703	703
Gas used in heating systems (TJ)	130	130	130	130	130	130
Total gas conveyed (TJ)	165,266	162,683	163,097	163,836	164,786	166,071

B.5. Schedule 13: AMMAT

We explain our approach to forecast escalation in Section 8.1.1 of the AMP. This provides an explanation for differences between nominal and constant price capital expenditure forecasts (Schedule 11a) and operational expenditure (Schedule 11b).

Company Name	First Gas Limited (Transmission)
AMP Planning Period	1 October 2020 – 30 September 2030
Asset Management Standard Applied	PAS 55000 - Transitioning to ISO 55000 Standard

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?	3	Asset Management Policy is authorised, published and communicated to all relevant stakeholders.		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 4.3.1b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1c). 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 4.3.1d) 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 standards		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).

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.

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?	3	The AMP is communicated to all relevant personnel through the Firstgas website. Key stakeholders will be issued with a copy of the AMP for reference.		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 appropriate.		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.		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 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. EMP is tested in emergency exercises regularly. These include emergency service involvement.		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.

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.

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 a person 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 4.4.1g).	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?	2	Firstgas has controls in place for the engagement of third party suppliers/contractors that ensure the provision of services is in line with Firstgas objectives.		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.

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.

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)?	3	Firstgas has training needs of personnel well developed and implemented. There are some known holes in training implementation, however these areas are being rectified.		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?	2	Firstgas aligns training requirements with established competencies in pipeline 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 appropriately trained. These have been developed in accordance with the requirements of AS2885 and audited by Lloyd's Register as part of the Certificate of Fitness. Training of personnel is incomplete		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?	3	Firstgas aligns training requirements with established competencies in pipeline 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 appropriately trained. The validation of competency forms part of the Pipeline Certificate of Fitness provided by Lloyds Register.		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.

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.

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?	3	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.		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 describes the main elements of the asset management system. This covers the main elements.		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	Firstgas use Maximo, Qmap, NRams and Meridian as an Asset Management Information systems. These systems contain data to be able to support the whole life cycle. This includes information originating from both internal and external sources.		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	Firstgas has developed controls that will ensure the data held is of the requisite quality and accuracy. Audits are undertaken. Firstgas uses a number of interrelated systems to retain asset information. Maximo – maintenance and event management, Qmap for procedures, NRAMs for non routine asset planning and Meridian for asset information. Controls are in place and being further developed to ensure the accuracy of the data is consistent and maintained.		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.

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.

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 an asset management information system which aligns with its asset management requirements. A recentexternal review of the system by AECOM confirmed that it is relevant to our needs.		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 assessed on a five yearly basis through formal Safety Management Studies. New assets and modifications to assets are assessed of operational risk through a formalised HAZOP process.		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 ensure proper close out. Where resource or training needs are identified,		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 the Worksafe, Commerce Commission and industry bodies to maintain an awareness of changes in legislation. The General Manager Regulatory and Commercial is responsible to ensure changes are incorporated into the		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	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.		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.

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.

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 control cost, risk and performance?	3	Firstgas has documented review processes in place for all critical documentation. The review process includes the auditing of the documents and processes by an internal auditor to ensure that the processes work. Action derived from these audits are incorporated into the asset information system for completion by a document owner.		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	Firstgas has asset performance monitoring linked to asset management objectives in place. There are a number of leading indicators and analysis of this data.		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 fully developed processes for the handling, investigation of asset related failures, incident and emergency situations. This is documented in the position descriptions for those leading these processes. Mitigation strategies developed from investigations and assigned an owners and included in the asset information system for		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 is required to undertake an external audit of the Asset Management System every five years to maintain a Certificate of Fitness of the transmission system. This is performed and documented by Lloyd's Register. Firstgas employs an internal auditor for the sole purpose of ensure internal processes associated with the asset management system are met and any deficiencies identified and remediated.		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.

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 control cost, risk and performance?	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.

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 an non conformance is identified , an investigator is assigned to perform 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 responsible to ensure the actions are implemented. An audit is carried out on completed investigations by the internal auditor to ensure that the actions have been		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	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.		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?	3	Firstgas actively engages with stakeholders and industry groups to share information on technology practices. Where improvements are identified they are reviewed at a concept level and if they provide a benefit they are implemented as appropriate.		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.

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	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.
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?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically 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.
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?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	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.

B.6: Schedule 14a

We explain our approach to forecast escalation in Appendix J of the AMP. This provides an explanation for differences between nominal and constant price capital expenditure forecasts (Schedule 11a) and operational expenditure (Schedule 11b).

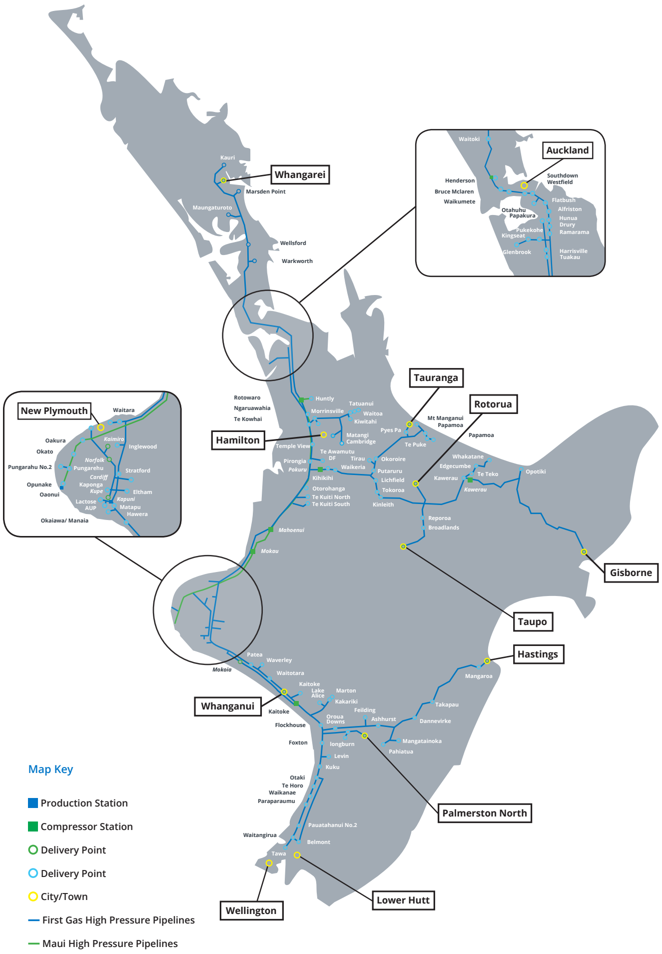
APPENDIX C: NETWORK OVERVIEW

This appendix provides an overview of our gas transmission network.

C.1. OUR GAS TRANSMISSION NETWORK

Figure 1 below shows the areas of the North Island served by our gas transmission network.

Figure 1: Map of gas transmission pipelines



C.2. NETWORK OVERVIEW

First Gas Limited (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 2,514 kilometres of which approximately 133 kilometres 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 in diameter. Buried pipelines are both externally coated and protected by cathodic protection systems. The pipelines are constructed to recognised standards in accordance with appropriate legislation. In certain areas sections of pipeline are installed above ground, such as special crossings over major natural features or manmade features.

The pipelines connect 252 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 our gas transmission system at a number of receipt points. The majority of our 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.3. KEY STATISTICS

Table 1 below sets out key statistics for our gas transmission network (as at 31 March 2020).

Table 1: Key Statistics

STATISTIC	VALUE
System length (km)	2,514
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**.

Asset Categories

Gas transmission networks are made up of a number of distinct asset types. We use a number of categories to organise our asset base.

Pipelines

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

Main Line Valves

Compressor Stations

- Reciprocating
- Gas turbine
- Electric

Station Components

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

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

C.4. PIPELINES

Our 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, the majority of 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.

Our 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.

The majority of pipelines are installed on land over which we have formal easement rights documented with landowners. This ensures we have 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 we have statutory rights of access. 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 we have no formal access rights. The landowners in these situations are private, government, Iwi, business or local authorities. In the majority 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 a number of activities or changes in condition which 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
- Findings from routine monitoring
- System improvements
- System modifications
- Inspections and 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 takes into account 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 last review was conducted in 2017.

In addition to remaining life reviews, Safety Management Study (SMS) reviews are conducted at a minimum of every five years, or when there is a signification change to the transmission system design or operations. The SMS and subsequent reviews are conducted in accordance with pipeline standard *AS 2885* and address any issues that could impact on pipeline condition.

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 2: Pipeline age profile

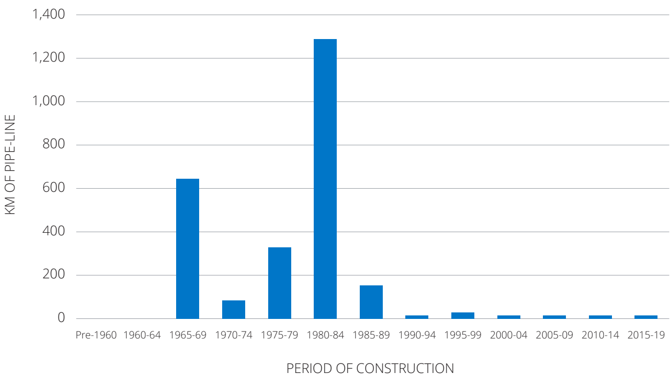


Figure 2 illustrates that the majority of our pipelines are over 30 years old. Pipelines are not typically replaced or realigned unless there are specific triggers to do so. However, as the pipeline age profile increases pipeline coatings, particularly older coal-tar enamel coatings, can deteriorate.

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 a number of specific instances where remedial work will be required to maintain integrity.

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' (Pipeline-Inspection-Gauge). The tool is inserted into the pipeline at dedicated launch and receive locations, and allows the maintenance and inspection activity to be completed without stopping 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 condition reports on the pipeline.

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 our transmission system, as defined in the Pipeline Integrity Management Plan (PIMP) is shown in Table 2.

Table 2: 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[1]
300	Frankley Rd-KGTP	500	47	10 years
400	Oaonui – Frankley Road	850	45	10 years
400	Frankley road – Huntly Offtake	750	247	5[2] years[3]
400N	Rotowaro-Southdown	350	92	5 years
403 (I)	Huntly Power Station	400	9	10 years
430[I]	Westfield – Henderson	200	35	5 years
500 [II]	Kinleith-Kawerau	200	103	10 years
601/605	Otaki SS-Belmont	300	17	10 years
602/603/604/606	Hawera-Kaitoke	300	88	5 years
700	Feilding Offtake-Hastings	200	153	10 years
715	Stratford-Ahuroa	450	8	10 years

Excavations to verify ILI data and repair any defects found are undertaken following ILI surveys. Cleaning PIG runs are conducted at varying interim intervals for each pipeline based on operational knowledge and the history of each pipeline.

ILI vehicles are able to be fitted with geospatial mapping tool units that gather very accurate, three-dimensional positioning of pipelines. This data can be used to calculate pipe bending strain that is commonly associated with land movement around pipelines. We are continuously considering the deployment of these units during ILI surveys in areas where land movement is known or anticipated to assess pipeline integrity risk.

Risks and Issues

Geo-hazard Risk

The impact of geo-hazards and how this translates to pipeline integrity risk is a current focus for Firstgas. Our analysis has identified a number of high geo-hazard risk areas, and a dedicated programme has been initiated to identify the individual risks on these sections. The resultant risk will then be assessed by the Pipeline Integrity team. Additionally, the review of the Geohazard Management Strategy in 2019 lead to a revision of the ILI frequencies for several lines. A 5 yearly strain-based mapping (IMU) ILI inspection was added to support the geohazard management programme.

1. The interval period has been reduced from 10 to 5 years. In 2019, Firstgas completed a piggability study alongside a review of the Geohazard Managenent Strategy. The result of these reviews lead to a revision of the ILI frequencies for the 200 line. In future, as part of Geohazard Management a 5 yearly strain based mapping (IMU) ILI inspection will occur on the 200 line.
2. 5 yearly ILI run for Strain assessment, & 10 yearly for MFL.
3. The Tihiroa to Huntly Offtake Section of the 400 Pipeline has a 10 year interval for ILI Pigging.

Geo-hazard risk

Geo-hazard is the term we use for land instability events, such as landslides, erosion or movement of rocks or debris, that has the potential to affect the integrity of transmission pipelines.

Our geo-hazard management processes consider the risks posed by activities that can result in a geo-hazard event, including:

- Earthquake
- Landslides
- Heavy rainfall
- Human activity

Landslides that penetrate to burial depths (typically 0.9 to 2.5 metres), or induce damaging stresses at those depths, pose a hazard to a pipeline. For example, surface erosion may result in a loss of pipeline cover leaving the pipeline exposed and at risk to operating outside minimum code requirements, or damage from being struck by debris or machinery. Furthermore, deeper landslides can induce enough stress or strain to a pipeline to result in deformation, or potential loss of pipeline integrity and containment.

Land Movement and Erosion Issues

Monitoring of threats to the pipeline from ground instability slips and/or erosion is detailed in the PIMP and works are scheduled in the planned maintenance system or completed as capital work.

Extreme weather events impact on parts of the transmission system that may result in riverbank erosion or slumping and in some areas, land slippage reducing cover over the pipeline. These events trigger reactive work to remediate the issue or additional monitoring.

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 our asset integrity management system, along with the ILI and cleaning pigging reports, has enabled us to understand more about the pipeline integrity risk.

As a result, we have begun to investigate further monitoring activities aimed at achieving a greater understanding of the condition of our pipelines.

These activities include:

- Reviewing piggability options for small diameter pipelines (100mm or less). A review of the smaller diameter lines was completed as part of the recent piggability study. Whilst the study touched on new technology for smaller diameter lines, it did not make a specific recommendation. Firstgas is in the process of determining the best technology to apply to suit the different pipelines. The next stage is to take the study into FEED for those pipelines that have been identified "easily modifiable", or thoselines that have been identified as having higher integrity risk profiles.
- Investigating suitable methods to measure pipeline corrosion at cased crossings.
- Investigating suitable methods to inspect un-piggable pipelines and short laterals.

Key projects

A number of key projects have been identified over the planning period. As our understanding and monitoring of geo-hazards improves, additional areas may be identified for remediation.

Key projects planned for, or underway include:

- The 100 pipeline supplying gas between Kapuni gas treatment plant and Wellington is critical for maintaining supply and accommodating demand growth in Wellington. A recoating programme is being prioritised and is planned to be initiated in FY2021 to recoat some sections of the pipeline. The existing coating has been in service for over 50 years. The programme to address the issue will continue throughout the remainder of the 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**.

Over the page is a table of the identified high risk geohazards and actions undertaken.

Table 3: Status of significant geohazards

LOCATION	HAZARD	NOTABLE POINTS TO HIGHLIGHT	ACTIONS	ASSESSED RISK[4]	CHANGE IN RATING	STATUS
Gilbert Stream	Loss of pipeline integrity due to erosion of the cliff face.	Coastal monitoring indicates that minor erosion is ongoing and that the clifftop is within 10 metres from the pipeline.	Relocation project released to detailed design and materials ordering Routine monitoring ongoing.	High	No change	The project to mitigate risk has been initiated, with execution planned for FY2022. Geohazard feature monitoring has been implemented and managed by Pipeline Integrity team.
Pipeline Awakau Road No.1	Pipeline traverses near the crest of a ridge.	Pipeline within 0.7 metres from the crest of the steep sided ridge.	Pipeline integrity review required. Routine monitoring ongoing.	Intermediate	No Change	Site is on the Geohazard remediation works list. Firstgas completed the design phase of this location in FY2019. This will allow the execution phase to be completed during the summer months of FY2021.
Awakau Road No.2	Slope Stability.	Pipeline traverse, and area has been identified historically.	Pipeline Integrity review and Field Assessment required.	Intermediate	No Change	This site was identified in the FY2019 geohazard remediation works plan. Execution phase was completed during the summer months of FY2020. Minor punchlist items to complete.
Mokau Land Movement	Slope Stability.	Pipelines ascend a steep slope from State Highway 3.	Ongoing monitoring monthly Pipeline Integrity review required.	Intermediate	Changed from High to Intermediate	Project already underway, and Pattle Delamore Partners (PDP) engaged in FY2019 to complete detail design. This will be completed at the end of FY2020 and earthworks project will be completed in FY2021 during the dry season.

4. Based on Firstgas geohazard risk ranking tool.

Table 3: Status of significant geohazards

LOCATION	HAZARD	NOTABLE POINTS TO HIGHLIGHT	ACTIONS	ASSESSED RISK[5]	CHANGE IN RATING	STATUS
200 Pipeline Huhu Road Weir Remediation	Landslide	Remediation of the stream bed is required to prevent further erosion and bed degradation around the 200Line.	Place rock filled gabion baskets and Reno mattresses around the pipeline and complete fish pass works.	Intermediate	No change	Ecological assessment completed. Progress to detailed design, requested installation prices. Consent application preparation.
300 Line Managawhete Stream Erosion Remediation	Erosion	The Mangamawhete stream near Derby Rd is eroding on the extrados of a bend on the true left bank. This is immediately upstream of a major pipeline crossing on the 300 line.	Install bank stabilisation in form of RipRap placement and riparian planting in backfill.	Intermediate	Changed from High to Intermediate	Project is in progress to address the risk. It covers the installation of a bank stabilisation in form of rip rap placement and riparian planting in backfill.
Mangapukatea (White Cliffs)	Loss of pipeline integrity due to the erosion of cliff face.	Coastal monitoring indicates that erosion is ongoing and that the clifftop is within 25 metres from the pipeline. There are areas of additional interest noted.	Coastal erosion assessment review being completed by GNS Jan 2017. Routine monitoring ongoing.	Low	No change	A project technical review, supported by geotechnical engineering consultants and GNS has been completed in FY2020. Emergency response plan strategy is up to date.
Gibbs Fault Above Ground Pipe Corrosion Remediation	Fault	Extensive pitting corrosion was found on the lower segment of the 100-line. The corrosion affected the lower segment of the pipeline/s near the bridge that crosses over the pipelines.	The bridge drain slots should be blocked to prevent water from running off the bridge deck directly onto the pipes.	Low	No change	Site remediated with ease of access for inspection and reduced risk of re-occurrence of corrosion. Avoid future pipeline repair due to corrosion becoming active.

5. Based on Firstgas geohazard risk ranking tool.

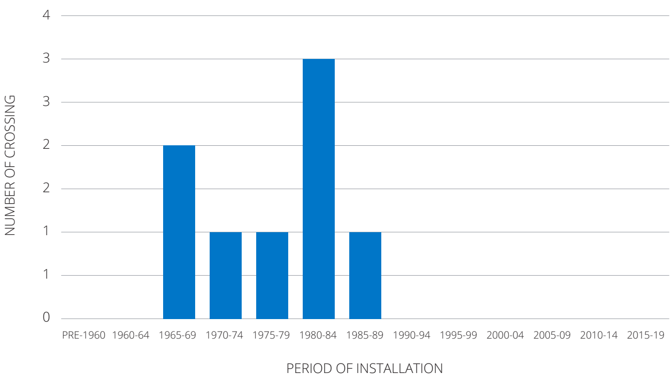
C.5. SPECIAL CROSSINGS

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 3: Age profile of Special Crossings



Typically, the structures are not replaced or subject to major refurbishment. Any remedial works beyond routine maintenance would usually be an upgrade to the existing structure to extend the asset life.

However, the results of ongoing routine maintenance assessments and surveys of pipelines at special crossings is anticipated to require future annual expenditure.

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.

Figure 4: Pipelines at Gibbs Fault near Wellington

Risks and Issues

The biggest issue with special crossings is limited access. 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 land owners, NZTA, local or regional councils.

Key Projects

There are currently no major projects planned for our special crossings. However, provision is provided within the forecast for minor works to ensure that if any of the structures do require refurbishment or upgrade it will be possible to complete them.

C.6. 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 cathodically 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.

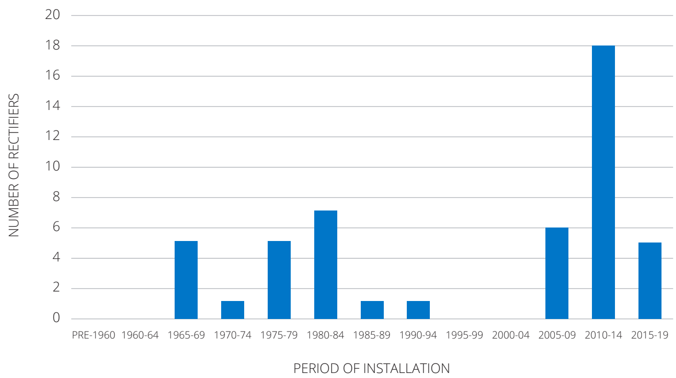
A rectifier site consists of the following items of equipment:

- 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. The majority of insulating joints are located at stations. A provisional amount is included in the forecast for replacement of failed insulating joints.

Figure 5: Age profile of rectifiers



The age profile above shows that approximately 40% of the fleet of rectifiers are over 25 years old, with the oldest being more than 50 years old. The older rectifiers have a design life of 25 years.

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. A prioritised replacement programme has been initiated to manage the replacement.

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, we can determine which anode beds are reaching the end of their life. This is normally observed over years not days or months so there is sufficient lead time to plan replacement. Replacement of failing anode beds is included in the rectifier replacement expenditure forecast.

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 program. 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

Currently, there is a project to replace CP test points that need to be replaced or upgraded to the current Firstgas standards. The scope of this work is to replace or upgrade multiple locations across Firstgas' transmission pipeline assets.

Figure 6: Typical pole mounted rectifier unit

C.7. 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 that 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.

A programme is underway to establish an inventory of all the off-pipeline assets. Once complete, the condition and current maintenance practices will be evaluated. All the off easement assets of the 400line have been captured and identified. The program is still in progress.

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 our asset management approach.

Key Projects

We are continuing with a programme of identification of all transmission system off-pipeline assets to ensure that appropriate routines are in place for the long-term management of our assets.

Figure 7: Typical off-pipeline assets

C.8. 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 that fits into the pipeline and is pushed along by the gas flow. PIGs can be used for internal cleaning (or scraping) of pipelines. 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 receivers 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 is underway and planned to be completed 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 has 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.

C.9. 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 32 kilometres throughout the length of the gas transmission system, except in the Auckland metropolitan area. In Auckland, MLVs are nominally spaced at 13 kilometre intervals due to the higher consequence of pipeline failures. The MLV fleet consists of 86 main line valves, that 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.

A 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. In the event that the actuator fails to operate the valves can be operated manually by the use of a hand pump.
- Automatically operated via a local LPT (low pressure trip) unit that 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 Nominal Bore (NB) 400mm manually operated MLV fitted with a gas over oil actuator is shown in Figure 23 below.

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 operate the gate valves and rotary actuators are used to operate the ball valve types. Both systems use

Figure 8: Typical manually operated MLV

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.

MLVs 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 MLV remote actuation upgrade project was instigated in response to observations from the OSH Pipeline Inspectorate following the 2002 Himatangi pipeline rupture incident findings. Upgrades were carried out in stages over several years and are based on a risk assessment priority order.

Key Projects

Firstgas is currently undertaking a strategic review to identify the MLV assets that require replacing or relocating.

A large proportion of the main line valves were installed during construction of the pipeline and as a result, we are facing ageing fleet of assets, with associated age-related issues. A number of MLV actuators are now obsolete and valve sealing capability degrades over time, requiring more maintenance to be able to achieve an effective isolation. These issues together with a review of MLV locations due to urban encroachment around major cities has led to the need to review of our existing strategy and approach to MLV investments.

The ouptout of our review will define a programme of works to address the multiple issues across these assets.

C.10. 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. We have 9 compressor stations containing 20 compressor units in total. Our compressor fleet and configuration has been designed to give N-1 security of supply, either through multiple compressors on a site or a combination of compressor sites and network configuration.

Compressor units are either gas turbines driving centrifugal gas compressors, 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.

The main isolation valves at compressor stations are powered by hydraulic or pneumatic valve actuators and all stations have automated emergency shutdown (ESD) systems. All of the compressor stations have the capability of continuous operation. However, gas demand and network configuration determine the actual operating hours at each station.

Compressor stations may contain a number of other assets for example: buildings, MLVs, water bath heaters, metering systems, chromatographs. A list of the compressor units is included in Appendix D.

Fleet overview

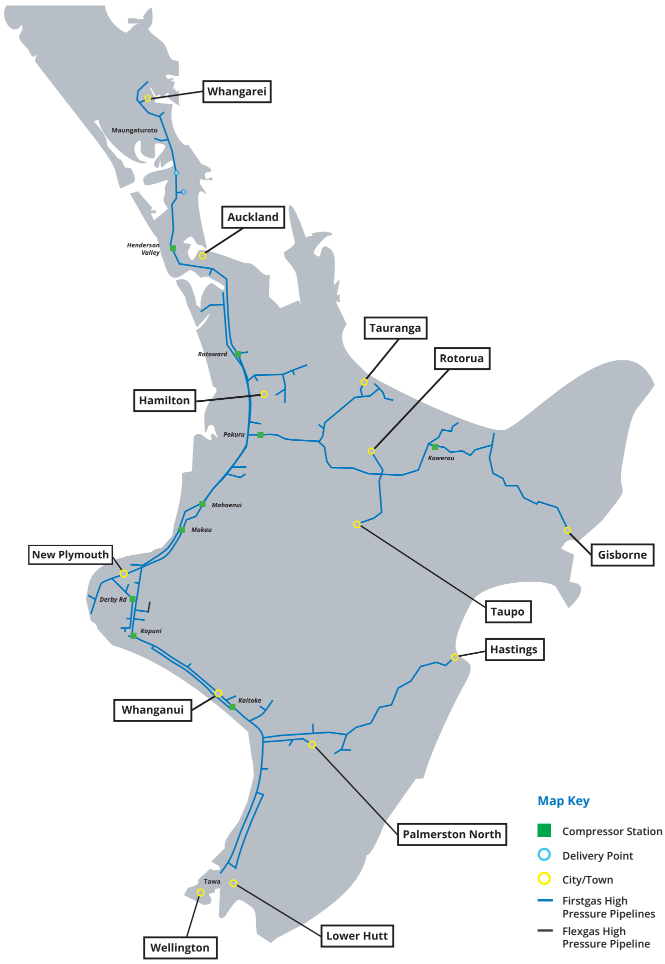
Gas compression sites do not just comprise compression units. The sites need to hold a considerable amount of auxiliary equipment to facilitate compressor operations. Gas detection, control systems, actuated valves and back up electrical generators are all part of the system that makes up a compressor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

Reciprocating engines

As the global fleet reduces, the manufacturing costs of parts increases due to the loss of economy of scale to the Original Equipment Manufacturer (OEM) who only make small production runs. In a manner similar to that of the turbo machinery, the reciprocating units were installed with an expected life of 30 years, and have been subject to review at the major inspections in order to allow extension of the life beyond that originally planned.

The OEMs are involved in the ongoing technical development of equipment resulting in new more efficient models being available, as well as upgrades to existing fleet machines. No significant upgrades to the units in Firstgas' fleet have been identified by the OEM. However, OEM service bulletins are provided as a guide to ensure continued effective and efficient operation of the machines is achieved.

Figure 9: Gas transmission compressor map



Overhaul costs are assessed to determine if it may be more financially prudent to replace an engine. Replacement is considered when an overhaul exceeds 60% of the cost of a replacement. If the capacity of the equipment is found to be lower than the forecast demand, then consideration is given to replacement of the asset with one of greater capacity. If the asset is likely to become redundant due to reduction in demand, then provided that N-1 redundancy can be maintained, the overhaul could be postponed.

Reciprocating engines have pneumatic control systems that are not sensitive enough to support the equipment operating regime and 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 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.

The upgrading of the control systems of the reciprocating equipment will allow operating data to be exported to a historian, and eventually online performance monitoring.

The technology being utilised for the control system upgrade is proven and mature and will remain supported for at least 30 years. The specific application of the technology will also lead to future proofing. For example, the use of local fibre optics for data / signal transmission means that as current copper cable equipment is replaced by direct fibre optic terminations, Firstgas will directly connect to the fibre optic networks installed.

The significant control system risk for the upgrade from pneumatic through to digital systems, is the reliance upon a stable power supply. We have implemented a strategy of upgrading the relevant Uninterruptable Power Supply (UPS) systems. We are also putting into place mitigation to provide short notice provision of auxiliary generating capacity, either through stand by generators on the specific compressor station or contracts to guarantee the supply of a temporary generator within a specific timeframe related to the UPS capacity.

Current vibration analysis is performed using external accelerometers applied by a third party on a routine basis (every two months), with the reporting of findings following on. This is not conducive to maximising the life of components as it prevents accurate prediction of when a component has entered a failure mode. If the component fails before being replaced, this can lead to more serious consequential damage.

The current philosophy is to replace components on an "hours run" basis, but this is not reflective of the actual remaining life when the operating conditions are considered, i.e. some components may have seen very little stress in operation and could survive a further inspection cycle.

The control system and associated monitoring equipment upgrade will facilitate online vibration monitoring.

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.

Specialist gas leak detection combined with the installation of Line of Sight gas detection systems has identified significant gas escapes from the compressor crankcases into the building. The root cause is that the current piston rod packing cases provide poor gas sealing when pressurised at start up and shut down i.e. when stationary. While they provide reasonable sealing under dynamic conditions, it is intended to upgrade the seal packing and packing cases. Also, it is intended to provide a vent path outside the building should the packing leak gas in future and indication remotely via the addition of a temperature sensor.

The age profile in Figure 24 reflects the installation of the compressors 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

Our newest compressors in the fleet consist of reciprocating compressors driven by electric motors with variable speed drives. These were installed at Henderson compressor station in 2017, in response to the increased demand on the pipeline due to the upgrade at Refinery NZ.

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

Turbine compressors

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

Gas turbines do not have a finite asset life as the design basis is for parts to be removed and overhauled at set frequencies. The planned change out of these parts is managed by the Capex expenditure programme. The basic design life of the gas turbine frame and enclosure is 30 years, but it is possible to extend the life based on the as-found condition, safety compliance and economic justification.

When an overhaul exceeds 60% of the cost of replacement, then replacement is considered. If the capacity of the equipment is found to be lower than the forecast demand, then consideration is given to replacement of the asset with one of greater capacity. If the asset is likely to become redundant due to reduction in demand, then provided that N-1 redundancy can be maintained at the compressor station, the overhaul could be postponed.

Major items and sets of parts that have a significant cost are not held or stocked by the OEM, though raw materials may be held, and as a result, procurement of spares can have an extended lead time. We do not hold major items or sets of parts on stock, though critical day to day spares are held.

Obsolescence of the rotating equipment is not an issue, as the OEM provides reverse compatibility data for upgrades. The technology is also suitably mature for alternate reverse engineered parts to be available, though this would then preclude the OEM supporting the machines going forward.

The gas turbine units require significant mechanical devices such as hydraulic pumps, pneumatic valves, relays and actuators that are subject to deterioration and obsolescence. While a reasonable level of stock is maintained to support local replacements and incidents, obsolete parts will generally become unsupported within three years of being declared obsolete and require a programmed change out. Major components such as gear boxes and clutches that have long lead times and have a significant impact on the ability of the unit to operate, are being identified and provisions for spares holding created.

The HOW fire gas and fire detection system monitors the atmosphere inside the turbine modules. It is no longer manufactured and became obsolete in 2014. Support for the system is via replacement of components only until OEM stocks are exhausted, this is estimated by Siemens to be in 2020. It is planned to replace in FY2020/2021.

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, we will be required to self qualify 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.

The Capex forecast is based upon further installation of the latest technology fire and gas detection systems and the potential ventilation and enclosure modifications required to the buildings.

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.

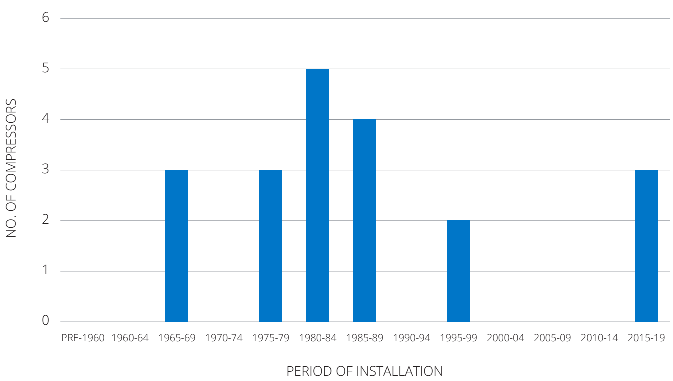
The changes in operating philosophy and upgrades allow for a more robust method of collecting and analysing the performance data. An effective historian system that is dedicated and developed for collecting and storing operating data provides the appropriate level of data and information investigation 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 Henderson compressor station it is intended to provide the same facility in Hamilton. This will provide readily available spares support for the northern area.

Gas coolers

New gas coolers were installed at Kaitoke #1 in FY2019 and there are other projects ongoing at Kapuni #3 and Pokuru #2 to address condition and performance issues. Localised repairs are available from the OEM, where a replacement is either not mandated or required. As the coolers are external and subject to both erosion and corrosion, a routine inspection programme is in place and a regular allowance for repair costs written into the ongoing cost of operation.

Figure 10: Age profile of compressors



Condition

Although the compressors age profile ranges from 1969 to current, major refurbishment and overhaul projects is condition based. Maintenance of all the compressors is completed in house, with support from contractors where required.

We have a support agreement with Rockwell Automation who supply PLCs for Rotowaro and Pokuru compressor stations. They are the preferred PLC supplier for gas transmission. This ensures that Firstgas receives the latest patches and updates on the installed systems. Our instrumentation and electrical technicians also receive Rockwell product training. Local external support is available for engineering and maintenance support on an ad-hoc basis.

Remaining life reviews conducted on four of the gas coolers have prompted the study to be undertaken on all the units. Further reviews will allow us to get a better understanding of the condition and provide better planning for the future.

Risks and issues

A condition and life expectancy study were completed to assess and advise on the life expectancy of the gas and water coolers across the fleet. To date Pokuru #1, Kaitoke #2 and Kapuni #2 and #3 assessments have been completed. Kaitoke #1 and Kapuni #2 and #3 have been assessed as needing replacement. Kaitoke #1 is completed, Kapuni #2 is yet to be replaced and Kapuni #3 is underway and expected to be commissioned in FY2020.

A technical study was conducted as part of a risk assessment on the hazardous areas of compressor stations. The recommendations from the report will be used to create a programme of works to ensure that all the compressor buildings reach an ALARP risk status.

Key projects

Our recent review[6] of transmission system compression requirements has identified that significant benefits can be realised by implementing a programme of upgrades to our existing compression fleet and operating the fleet as a single system.[7] We have subsequently developed a compression strategy that seeks to:

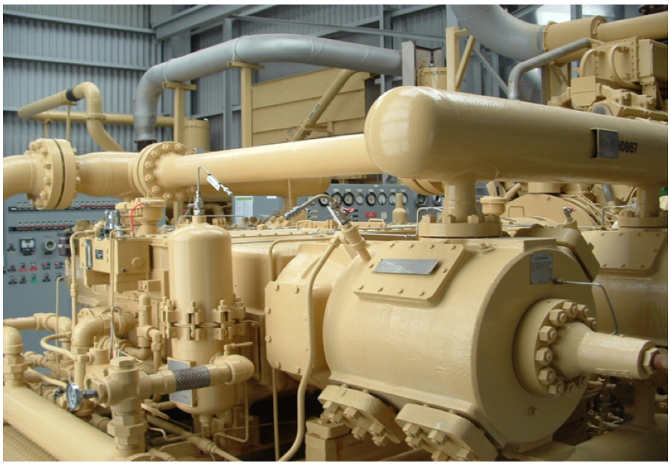
- Update and simplify an ageing fleet of compressor units, by utilising singular modular compression packages
- Minimise lifecycle capital and operational expenditure
- Improve reliability, security of supply and emergency response
- Provide flexibility to allow units to be relocated to match future changing system loads and opportunities
- Reduce asset integrity, security of supply and operational risks.

Four of our key compression sites are planned to be upgraded, Rotowaro compressor station, Kapuni gas treatment plant compressors, Mokau compressor station and the Pokuru compressor station. We anticipate that the Rotowaro compressor station will be upgraded first, with the work incorporating the construction and installation of the new modular compressor units, and modifications to the existing pipework to tie in the new units.

Shifting our focus from dealing with individual issues on compression sites to improvements across the network compression has resulted in a number of projects being cancelled:

- Planned replacements on the outdated pneumatic control systems at Rotowaro compressor station
- Replacement of the gas coolers at Pokuru
- Rewheeling of unit #1 Turbine at Mokau compressor station

Figure 11: Typical reciprocating gas compressor



C.11. 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 located 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.

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

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

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

6. The review was initiated in 2018 and was signalled in the 2019 AMP.
7. Historically the Maui and Non-Maui have been under separate ownership and considered as two systems for technical reviews.

C.12. ODORISATION PLANTS

Firstgas owned and/or operated major and minor odorant injection facilities together with the associated odour level and odorant concentration monitoring points. The major odorant injection facilities are Kapuni and Rotowaro compressor stations, Pokuru offtake and Pirongia delivery point. The minor odorant injection facilities are some delivery points in the gas transmission network.

Delivery points deliver gas and are odorised upstream. Odour level and odorant concentration monitoring points for Firstgas are determined by the field operations manager. The odorant used by Firstgas usually is a blend containing 80% tertiary butyl mercaptan and 20% iso propyl mercaptan. Any change to the existing 80/20 blend shall be approved by the transmission operations manager.

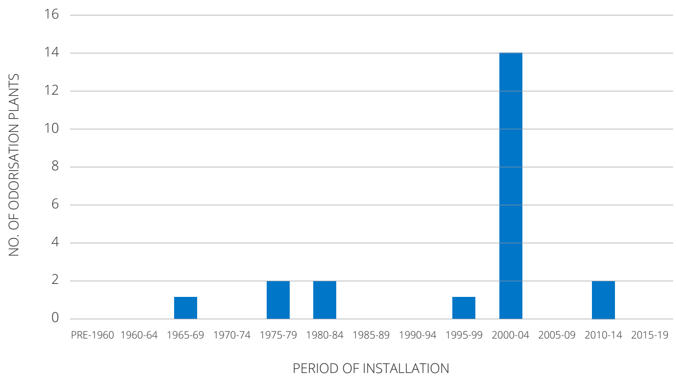
The minimum odorant (mercaptan) concentration throughout any distribution system is 3 mg/m^3. The odour level shall be readily detectable and of an unpleasant and distinctive smell at a concentration of gas in air of 1/5th of the lower explosive limit – i.e. 1/5th of 4.5% or 0.9% gas in air. This is measured by use of the heath odorator. No maximum limits are specified, but staff should be aware that higher than normal concentrations (i.e. above 15 mg/m^3) may give rise to an increased number of reported gas escapes and complaints of smells from appliances (particularly unflued types).

In order to maintain odorant tank levels, the gas control advises relevant field technician when minor sites odorant tank levels get to 25%, by raising a Maximo service request.

Fleet overview

Odorisation plants comprise of a number of components such as odorant injection tank, pumps, valves and instrumentation. Odorisation plant maintenance and inspection activities can be found in **Appendix K**.

Figure 12: Age profile of odorisation plants



Condition

More than 80% of the odorisation plants are in good conditions, with normal deterioration requiring regular monitoring.

Risk and issues

The odour levels and odorant concentrations are set by the requirements of NZS 5263 to ensure minimum levels are exceeded at the extremities of all the networks. Monitoring of both odour level and odorant concentration testing is carried out in accordance with NZS 0020. In the event of odour fade or masking being detected the actions detailed in NZS 0020 are in place to institute precautionary actions and provide awareness to consumers, emergency services and media as appropriate.

Key projects

There are no major projects planned.

C.13. 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 come in 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.

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

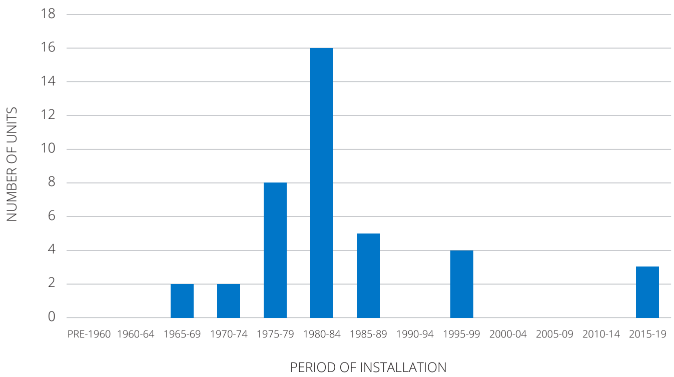
Coalescers are installed on the discharge side of compressor stations to prevent oil mist carry over into the pipelines from compressor units. Filter separators are installed on the suction side of compressor units to protect the prime movers from contamination. Coalescers and filter separators are also 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 a number of components including:

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

Figure 13: Typical reciprocating gas compressor

Figure 14: Age profile of coalescers



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*.

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.

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

There are no risks or issues identified with the filter separators/ coalescers.

Key Projects

Currently, there are no facilities to control contamination that may be present in the 300 line with the line terminating at KGTP, and the contamination could be brought in during pigging operations. A project was initiated to identify what contamination control facilities are required on-site to ensure that future pigging operations will have minimal impact on normal functioning within the plant. The project identified filter replacement was required.

Before work can begin on filter replacement we need to replace the valves that will allow isolation of the equipment required to allow the filter to be installed. A major project to replace the valves is scheduled for FY2021.

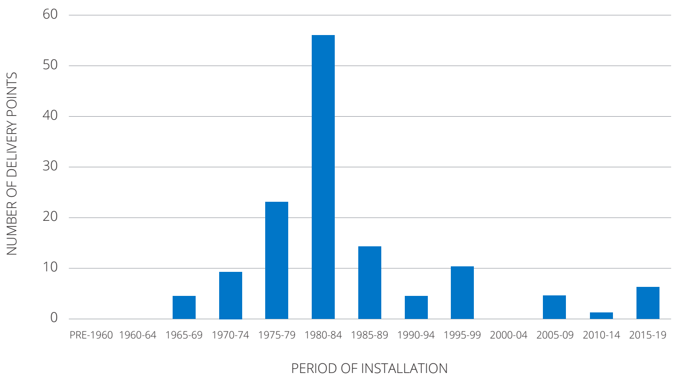
Firstgas will also complete a written strategy on filter and coalescer replacement in FY2021.

C.14. DELIVERY POINTS

Delivery points reduce the gas pressure in the system prior to it being delivered to customers and/or into downstream distribution networks.

Figure 15: Typical delivery point

Figure 16: Age profile of delivery points



Fleet overview

Delivery point equipment can include a number of components including:

- Filters
- Heating systems
- Isolation valves
- Pressure regulators and control valves
- Pressure safety valves and slam-shut valves
- Metering systems
- Pilot valves
- SCADA and communications
- Gas chromatographs
- Station ancillaries

Condition

More than 90% of the delivery points are in good conditions, with normal deterioration requiring regular monitoring.

Key projects

Components of delivery points are part of other sections such as filters, heating systems, SCADA and so on; which include key projects in the next planning period.

C.15. 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 as long as external corrosion is prevented. Non-destructive testing (NDT) of large filter vessels sometimes reveals material defects that require remediation. These filter material defects tend to come from the original construction.

Risks and issues

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

Key projects

A programme will be developed to plan the replacement of existing small filters with current good practice models. The programme will start in FY2021.

For odorisation plants an allocation is included in forecasts to conduct minor works.

C.16. 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 a number of 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 a number of components including:

- Electric heater pressure vessel including electric elements
- Control system

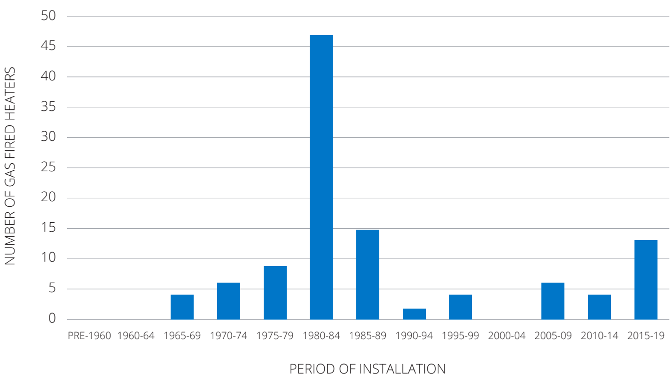
Heating systems are typically incorporated within the following stations:

- 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.

Firstgas has initiated a replacement programme for aging WBH and it is part of the key projects for this fleet. Water bath heaters are typically installed at the time of delivery point or station construction. Maintenance reports and system modelling will highlight those stations where the existing heater performance needs to be reviewed and acted upon if required.

Figure 17: Age profile of water bath heaters



In order to provide sufficient heating to the gas entering a station, various sized water bath heaters are in service. The heaters are referenced according to their inlet piping sizes.

Although heater age is in excess of 40 years in some instances, the WBH refurbishment programme extends the asset life, which aligns with our asset management strategy.

Condition

Improvements in equipment design and corrosion inhibitors has significantly improved water bath heater internal condition. Over 60% of the gas fuelled WBHs have been refurbished within the last 10 years. The intention is to continue with the strategy until all the heaters have been replaced. Once the strategy has been completed alternative inspection techniques will be assessed for suitability.

Corrosion inhibitor protects the internals of the shell and tube while external corrosion is managed through our corrosion management strategy. This allows any corrosion defects to be risk assessed and remediation prioritised. As part of the routine maintenance programme, WBH corrosion inhibitor samples are tested.

Electric heaters do not use water as a heating medium and are therefore are not subject to the same internal corrosion concerns.

Risks and issues

A number of issues have been identified associated with heating systems including:

- Automatic low water level cut-out switches are not fitted as standard on heating systems and consideration will be given to retrofitting these protective devices.
- Electronic controls are mandatory *(AS3814)* for WBHs above 275 kW. These are relatively complex control and protection systems designed to detect main flame failure within three seconds and to prevent explosive mixtures being generated in the combustion chamber when a fault occurs. Some large WBHs do not incorporate appropriate control and protection systems and thus may require upgrading.
- On some WBHs the existing over pressure protection on fuel gas trains and burner control systems have been identified as requiring upgrades.
- Environmental operating conditions at some locations can be an issue effecting the reliability of the WBH, particularly in windy areas. Although considered low risk, installation of minor improvements such as flame stabilisers or down draft preventers improves heater performance and reduces callouts.

Key projects

The current focus for WBHs is to initiate and maintain our new WBH replacement programme, to ensure that we are compliant with our pressure equipment management plan. Moreover, electronic controls are mandatory *(AS3814)* for WBHs above 275 kW.

The new WBH strategy will be developed in subsequent years.

C.17. 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.

The majority of 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 8,000 valves throughout the gas transmission system. A central register for all outstanding asset related issues is used to prioritise and plan when the works are to be completed. 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 by the use of 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.

Key projects

Faulty valve replacements are undertaken through a coordinated programme of works. Individual valves are risk assessed to prioritise replacement. The complexity of the replacement can significantly drive up the cost of the programme.

C.18. 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 diaphram designs through to pilot operated valves and more complex pressure control valves. Pressure regulators that use 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 therefore, are an essential component for the prevention of over-pressurisation of a downstream pipeline. Typically, a second 'monitor' pressure regulator is fitted asa 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 that 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. In some cases, serious reliability problems resulting in loss of pressure control can be manifested suddenly as a result of changed pipeline conditions etc. The failures may include shaft breakage, pilot failure/blockage, diaphragm failures or tube swelling. Regulators which exhibit serious reliability problems will be replaced on an as required basis.

Maintainability is the ease with which a regulator can be maintained. In general, complex pilot operated regulators are more difficult and expensive to maintain than simple-direct-acting regulators. In-line maintainability (whether a regulator can be serviced without being removed from the pipe) is considered desirable although it is not a critical factor.

Regulators are considered to perform well if they are capable of delivering 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.

The serviceable life of pressure regulators depends on regular maintenance and inspection. However, experience has shown that when pressure regulators reach ages of 30 years and older the probability of malfunction increases.

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

The obsolescence of the Grove Flexflo regulators has driven a North Island-wide replacement programme over the course of the last 5 years. In addition to replacement of the regulators, we have taken to opportunity to review our pressure regulation controls onsite. Where possible, we now incorporate slamshut vales as an additional safety device to prevent over pressure incursions.

As a result of the replacement programme we have seen an uplift in the overall condition of the pressure control equipment on site.   Provision is included in the expenditure forecast to complete the replacement of all 1 inch – 3 inch Grove Flexflo regulators. To ensure that all the regulators are replaced before the spares have been depleted or are out of date, the regulator replacement programme has been accelerated over the last three years.

As well as regular function check routines on regulators, external condition inspections are carried out on all our assets. This allows for the prioritisation of corrosion defects if required.

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 still be in service. Failure to replace the existing Grove regulators before depletions of spares will result in a considerable risk to the organisation and the equipment becoming non-maintainable.

There are other regulator risks around the network. There has been a number of o-ring issues in Gorter regulators that have resulted in serious failures. The solution may be relatively simple (change of O-ring material), but if it is not successful, a more dramatic solution may be needed.

Key projects

The Grove Flexflo replacement programme has been the focus for regulators asset replacement and renewal. Firstgas is completing replacement at the last stations on the list, with the Grove replacement programme expected to be completed in FY2021.

C.19. 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. 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.

Some relief valves in the statutory testing programme are not identifiable. While they continue to test correctly on a five-yearly basis, there is no known documentation to support them and consequently have uncertain spares support. A review of these relief valves was conducted during FY2014 and they were found to be satisfactory.

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

- Reliability
- Performance
- Obsolescence.

Condition

The need to manage relief valve obsolescence has driven a significant replacement programme.In addition to the regulator replacement programme described above, a large proportion of the assets have been replaced over the last 10 years. resulting in a general uplift in condition of the assets.

External condition issues are managed through the corrosion management process to identify and prioritise corrosion remediation.

Risks and issues

There are no significant risks or issues associated with relief valves.

Key projects

There are no major projects planned for pressure relief valves. An allocation is included in forecasts to conduct minor works.

C.20. 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 the majority of cases, metering data is transmitted to our gas control at Bell Block by either RTUs connected to the SCADA system or by Autopoll telemetry units. A few minor sites rely on periodic manual download of data.

Energy quantities are calculated on site at some major delivery points and receipt points. In the majority of cases however, energy quantities are calculated using office based applications.

Metering systems contain a number of 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

Figure 18: Typical ultrasonic metering system

Figure 19: Age profile of rotary meters

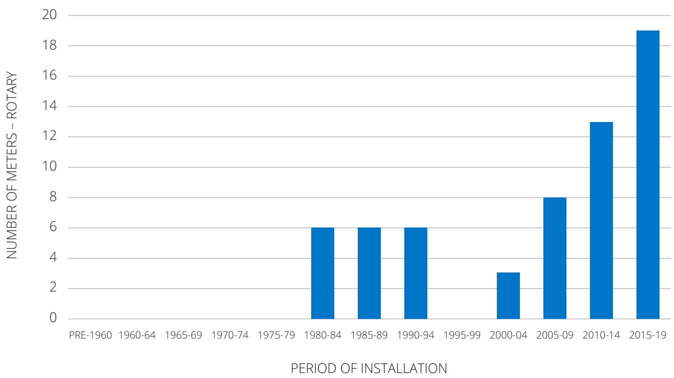
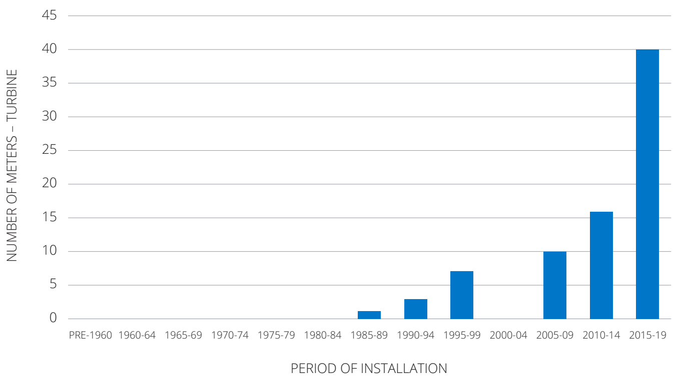


Figure 20: Age profile of turbine meters



Some metering systems incorporate two meters. These are termed primary and verification meters, and provide for redundancy and testing. Some stations have more than one metering system e.g. where gas is delivered to separate downstream systems from the same delivery point.

Fleet overview

As an alternative to turbine meters, ultrasonic and Coriolis meters are also now available. This has opened up 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.

By having a continuous replacement programme, meter technology advancement can be incorporated in the replacement programme that can reduce overall maintenance requirements and provide more accurate metering.

Condition

A programme of meter replacement has been in progress since 2009. At present, this is focused on metering systems incorporating obsolete turbine meters, metering system components are usually replaced on a time basis to prevent obsolescence and end-of life failures.

A trial conducted during FY2015 has demonstrated that a typical metering system incorporating an obsolete turbine meter is almost 1% slower when compared with a new turbine meter. Typically, the cost of a new turbine meter would be recovered with one year due to increased accuracy.

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. A number of larger meters are now approaching or have exceeded 20 years and becoming obsolete and spare parts are no longer available from manufacturers.

A number of 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.

Key projects

The two metering systems at the Ammonia Urea Plant (AUP) are obsolete, and neither set of meters complies with good metering practice. For that reason, work is underway to replace the existing metering equipment. The main detailed design has been completed, and additional work is required as a consequence of operations advice such as the incorporation of a reliable twin stream gas chromatograph and appropriate instrumentation on the gas filtration equipment. The project target date to complete execution of the works is FY2021.

C.21. SCADA AND COMMUNICATIONS

The gas transmission system is monitored and partially controlled by a SCADA system on a 24/7 basis. The system is also used for coordinating the supply and delivery of gas through the pipelines, balancing available supply against forecast demand, and receiving metering system data.

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, which is backed up by two six-hour reserve battery banks and an emergency generator.

The system consists of a master station at Bell Block and RTUs installed at various stations to monitor the system. The master station communications tower is also located at Bell Block providing direct communications within the local area. The primary systems used are provided by Schneider Invensys Process Systems (IPS), using a Foxboro SCADA Rev-7 system, communicating with remote field RTUs linked to station equipment and instrumentation. Communications utilise internet protocol over fixed cabling and radio where a cable service is not available.

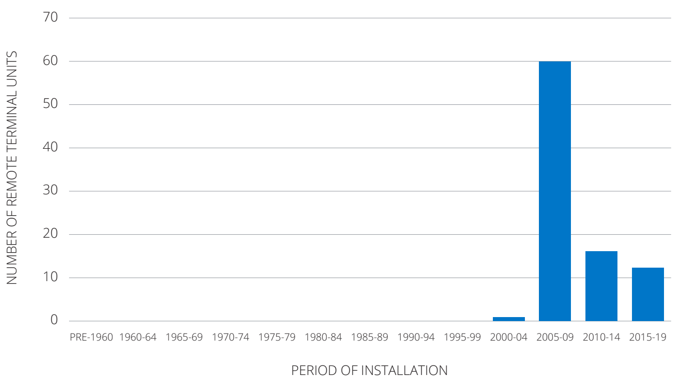
The SCADA system constantly monitors asset operating conditions at strategic pipeline locations including high-volume delivery points and delivery points at pipeline extremities. It also provides remote control of compressors and some MLVs.

Data gathered by SCADA is transferred to commercial allocation and metering systems. Hence it is subject to strict security and confidentiality requirements and is regularly audited by independent parties.

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.

Figure 21: Age profile of RTUs



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 break-downs. We will work with communications 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.

The current design life of RTUs is approximately 10 years, and although there are no specific issues associated with them, a replacement program allows new technology to be incorporated in a staged manner.

Condition

Although operational, the master system has exceeded if design life, is obsolete and is now unsupported.

There are currently no major issues associated with the existing SCADA RTUs and communication system. The Capex forecast for FY2019 – FY2022 has allowed for migrating communications services to fibre optic connections at existing RTU stations. New SCADA RTUs are installed at sites where demand has grown, or sites have become more strategically important.

Risks and issues

The expected useful design life of these systems was expected to be between 7 – 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.

Key Projects

The planned replacement of the SCADA RTU Central Processing Unit (CPU) is underway with the project to be completed no later than FY2022. There are 33 SCADA sites affected. Therefore, it is expected that the migration will take between 12 – 18 months to complete. The CPU replacement programme will address the risk before obsolescence becomes an issue.

C.22. 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, that are relayed to the flow computer to facilitate the calculation of gas energy flow. GCs contain a number of 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 taking into account 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 dew-point.

Risks and issues

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

Key projects

As part of the meter upgrade at the AUP, a GC will be installed. The main detailed design of this work has been completed. The project target date to complete execution of the works is FY2021.

C.23. STATION ANCILLARIES

A number of station equipment items are considered to be 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.

It is intended to develop a standard design and testing/acceptance criteria, to determine the life of all 24 volt DC battery charger units, and assess all stations against these criteria to determine priority for replacement.

A report was produced in 2011 on the issues and interactions between copper based electrical multiple earths neutral systems, carbon steel piping buried in the ground, and CP techniques and system. Many of the stations were built decades ago without a clear understanding of the electrochemical affects one system has upon another.

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 the majority of 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.

A schedule for condition assessment and implementation of CP on below ground piping in stations is included in the PIMP. The programme described in the schedule has not been implemented to date. Condition assessments have been carried out on an ad-hoc basis in conjunction with other excavation works in stations. To date, severe corrosion has been identified at ground-air interfaces only and mostly on non-pressure piping. Little or no significant corrosion has been identified below the interface.

The below-ground condition assessment and CP implementation schedule are ongoing.

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 two yearly). Defects that may constitute an immediate integrity threat receive an engineering assessment and are remediated as soon as practicable after 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.

The majority of 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.

Pipes 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. The replacement program work scope, is to cut down and remove the existing support, and replace with maintainable inspect-a-lift type pipe supports. A corrosion assessment is done once the pipe support has been removed. Outcomes of the assessment will determine if additional remediation work is required on the affected hardware.

Gas detection equipment (not associated with compressor units)

A review of all gas detection systems has been conducted which confirmed that our gas detection installations comply with *AS/NZS 60079*. The report did, however, identify that 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 a number of modifications being required at station assets. Provision has been made in the expenditure forecast for this activity. The Wellington area, Hawkes Bay area and Taranaki area EHMP studies have been completed. Waikato area, Manawatu-Wanganui area, Auckland area, Northland area and Bay of Plenty projects are underway.

Station fencing

A large proportion of the station fencing was constructed simultaneously and is now reaching the end of its service life. Although fencing can be repaired, often the cost to fully replace is comparable with the patch repairs. Where this is the case, the fences will be replaced.

Risks and issues

The earthing/bonding system for underground piping is often formed using copper or copper clad electrodes, and is connected via the station mains power supply to a much larger power network that also uses copper to form the earth. When copper and steel are electrically connected together, and both are exposed to soil, the steel will become sacrificial, resulting in corrosion to underground earthed piping. Stations with underground piping should be using zinc as the earthing system electrodes, and sacrificial zinc should be bonded to the underground piping in order to achieve protection. The 2011 report referred to above gives post-project performance test results for Kaitoke Compressor Station, which was upgraded to a zinc earthing system in 2011, with successful outcomes.

Many of the small to medium sized stations are using a single galvanised steel earth electrode to form the main earthing point. Based on the stations being gas hazardous areas and the earthing and bonding systems being of significant importance in order to achieve electrical safety, all sites with single galvanised earth pegs will be reviewed to establish if this is satisfactory to achieve required standards (including factoring in earth resistivity), and will be upgraded if required.

Most stations that have a 230V main power supply are not equipped with isolation transformers. Modern wiring standards require the installation of isolation transformers for risk mitigation. Consideration should be given to installing the appropriate isolation transformers as the opportunity arises.

Many stations do not have any form of Earth Potential Rise (EPR) protection. EPRs exist or are created when a fault current is passed through earth, due to the soil not being a perfect conductor (but in fact a resistor). This forms a voltage gradient across the ground. This may sometimes be referred to as step potential or touch potential. When these faults occur, which can be due to lightning strike on pipelines, electrified railway lines, electrical network system ground faults or power station faults, there is a possibility for EPR in nearby stations and pipelines. To mitigate this, a zinc ribbon conductor is normally trenched into the soil up to 500mm deep, which causes the EPR within the station to rise to the same magnitude as the steel piping in that station, thus if someone is touching both the ground and the piping when the fault occurs, they are not exposed to any potential difference in voltage. Very few sites have zinc ribbon installed, and a review of these sites has been completed to determine requirements at each station and provision has been made in the forecast for the required upgrade work. Factors such as proximity to power stations, proximity to electrical networks will be considered.

Where cross country pipelines enter into stations, generally the first flange set is used to electrically decouple the pipeline from the station piping. This is done using a Flange Insulation Kit (FIK). A surge diverter is required across a FIK in order to channel any surge voltages/current from the pipeline down to the earth system within the station, and dissipate the fault, rather than have the fault jump across the FIK which would result in the FIK being damaged and becoming conductive. There is however, an inconsistent application of surge diverters on the transmission system, and the more popular model used (Critec) does not give rise to adequate personnel protection nor does it have a power system fault duration rating. A review and further investigation will be conducted in order to determine a standard design for FIK protection. The types of surge diversion required will be based on the Pipeline Electrical Hazard Management Plan, which has now been completed.

Building issues: McKee Mixing Station, Henderson compressor Station, Papakura DP, Papakura Pressure Reducing Station (acoustic insulation, ventilation and alarm), Pokuru OT, Pokuru oil shed, Te Rapa DP (acoustic insulation).

Emergency gates: provision has been made in the AMP for the inclusion of additional emergency egress crash gates for AS 2885 compliance. This provides provision for safe exit from a station in the event of an emergency.

Power earthing and bonding: many of the power supply units are in excess of 20 years old, and are now unsupported for parts. There are two models of 24V DC power supplies to be replaced, to avoid unplanned outages.

Key projects

Typically, the issues identified under the station ancillaries are incorporated into broader projects scope where possible to provide some efficiencies in project delivery.

Currently, Firstgas is in the process of finalising and implementing the EHMP touch potential mitigation, and associated specifications and procedures. The EHMP study reports were completed in FY2018 and FY2019. The EHMP touch potential mitigation is expected to be finished in FY2021.

C.24. CRITICAL SPARES AND EQUIPMENT

We own a stock of critical spares and equipment for an anticipated range of pipeline repairs. Whenever new assets are introduced, an evaluation is made of the necessary spares and equipment items required to be retained to support the repair of any equipment failures.

Critical spares include items that are low volume turnover or have long lead times for purchase, are no longer produced (obsolete), or where the level of risk associated with not holding a spare is considered high.

The majority of the critical spares and equipment are held in our main stores facility in Bell Block. Critical spares and equipment includes:

- Steel pipes and fittings
- Composite repair materials
- Drilling equipment
- Stopple equipment
- Repair sleeves and clamps
- Spherical tees
- Valves.

In general the condition of the critical spares is satisfactory as found by regular inspection and maintenance. Critical spares are subject to compliance with technical standards and processes for their acquisition, management and maintenance.

Equipment

Plant and equipment is acquired or replaced as the need arises.

Risks and Issues

The two air transfer provers used for meter certification are now over 20 years old with limited availability of parts and an obsolete control system. Interim maintenance is keeping the equipment serviceable as it approaches the end of its life, with possible replacement being required in FY2019. It was necessary to rebuild the wiring and add mass proving capability to the liquid prover in FY2015 and it was replaced in FY2020.

Key projects

Firstgas operates plant and equipment in the measurement laboratory at the Bell Block site for the calibration and certification of metering system components owned by Firstgas and others. Issues identified with this equipment include:

- The two air transfer provers used for meter certification are now over 20 years old with limited availability of parts: One of the provers has been replaced, the other will be overhauled.
- The liquid prover is over 25 years old: Many parts are no longer available for the prover, and parts do not meet current standards such as the electric motor for the prover. The liquid prover will be replaced at the end of its serviceable life.
- Some calibration test equipment is over 20 years old and close to the end of its serviceable life: the PPC 3 (Pressure Controller and Calibrator) has intermittent bad faults, Firstgas is looking into the option to repair the kit.
- There has been an upgrading of the meters over the last several years. Therefore, there is a request for additional new rotable spare meters. Firstgas will acquire four new meters in FY2021.

APPENDIX D: ASSET DETAILS

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
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

STATION NUMBER	STATION NAME	ADDRESS	INSTALL YEAR
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
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

STATION NUMBER	STATION NAME	ADDRESS	INSTALL YEAR
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
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

STATION NUMBER	STATION NAME	ADDRESS	INSTALL YEAR
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
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

STATION NUMBER	STATION NAME	ADDRESS	INSTALL YEAR
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
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

STATION NUMBER	STATION NAME	ADDRESS	INSTALL YEAR
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
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

STATION NUMBER	STATION NAME	ADDRESS	INSTALL YEAR
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
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

STATION NUMBER	STATION NAME	ADDRESS	INSTALL YEAR
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
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	Whirokino Trestle Bridge Realignment	0.978	8620	May-18	219	200	6.35	API 5L X52	2 Layer FBE
100B	Duck Creek Realignment	0.548	8620	Sep-17	219	200	6.35	API 5L X46	3 Layer Polyethylene
100C	Endeavour Drive Realignment	0.373	8620	Sep-17	212.8	200	6.4	API 5L Gr X56 HFW	2 Layer FBE
100D	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
100E	Pig Pen Realignment	0.073	8620	Sep-17	212.8	200	6.4	API 5L Gr X56 HFW	2 Layer FBE
100F	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
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	6.751	8620	Jan-69	219	200	5.56	API 5L X42	Coal Tar Enamel
11A	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

PIPE #	PIPE NAME	LENGTH (KM)	MAOP (kPa)	DATE COMMISSIONED	OUTSIDE DIAM (mm)	NOMINAL BORE (mm)	WALL THICK (mm)	MATERIAL GRADE	COATING SYSTEM
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 – Yellow
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	API 5L GrB	Polyken
200	Kapuni – Papakura	335.263	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)
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	API 5L GrB	Extruded Polyethylene

PIPE #	PIPE NAME	LENGTH (KM)	MAOP (kPa)	DATE COMMISSIONED	OUTSIDE DIAM (mm)	NOMINAL BORE (mm)	WALL THICK (mm)	MATERIAL GRADE	COATING SYSTEM
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	8620	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	0.172	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
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

PIPE #	PIPE NAME	LENGTH (KM)	MAOP (kPa)	DATE COMMISSIONED	OUTSIDE DIAM (mm)	NOMINAL BORE (mm)	WALL THICK (mm)	MATERIAL GRADE	COATING SYSTEM
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[8]	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

8. 404 Line lateral is only suspended, Firstgas still manages the pipeline.

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	8620	Jan-83	60	50	3.20	API 5L GrB	Extruded Polyethylene – Yellow
419	Alfriston Lateral	0.059	8620	Jan-83	60	50	3.20	API 5L GrB	Extruded Polyethylene – Yellow
420	Huntly Town Lateral	0.029	8620	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 GrB	Extruded Polyethylene – Yellow
430B	Henderson Vly CS – Ruakaka	120.473	8620	Jan-82	168	150	6.40	API 5L X42	Extruded Polyethylene – Yellow
430C	Ruakaka – Maungatapere	29.020	8620	Jan-82	168	150	4.80	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

PIPE #	PIPE NAME	LENGTH (KM)	MAOP (kPa)	DATE COMMISSIONED	OUTSIDE DIAM (mm)	NOMINAL BORE (mm)	WALL THICK (mm)	MATERIAL GRADE	COATING SYSTEM
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
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

PIPE #	PIPE NAME	LENGTH	MAOP (kPa)	DATE COMMISSIONED	OUTSIDE DIAM (mm)	NOMINAL BORE (mm)	WALL THICK (mm)	MATERIAL GRADE	COATING SYSTEM
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
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

PIPE #	PIPE NAME	LENGTH (KM)	MAOP (kPa)	DATE COMMISSIONED	OUTSIDE DIAM (mm)	NOMINAL BORE (mm)	WALL THICK (mm)	MATERIAL GRADE	COATING SYSTEM
605	Waikanae – Belmont Loop	38.547	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
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
800	Lichfield – Tirau	14.099	8620	Jan-80	168	150	7.10	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
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
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
100	14058	Cased crossing	South Road SH 45	1968
100	95337	Cased crossing	Mosston Rd	1968

LINE	METERAGE	TYPE	LOCATION	YEAR COMMISSIONED
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
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

LINE	METERAGE	TYPE	LOCATION	YEAR COMMISSIONED
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
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

LINE	METERAGE	TYPE	LOCATION	YEAR COMMISSIONED
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
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

LINE	METERAGE	TYPE	LOCATION	YEAR COMMISSIONED
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
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

LINE	METERAGE	TYPE	LOCATION	YEAR COMMISSIONED
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
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

LINE	METERAGE	TYPE	LOCATION	YEAR COMMISSIONED
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
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: SCHEMATIC DIAGRAMS OF TRANSMISSION ASSETS

This section contains seven schematic diagrams of our 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 22 North System

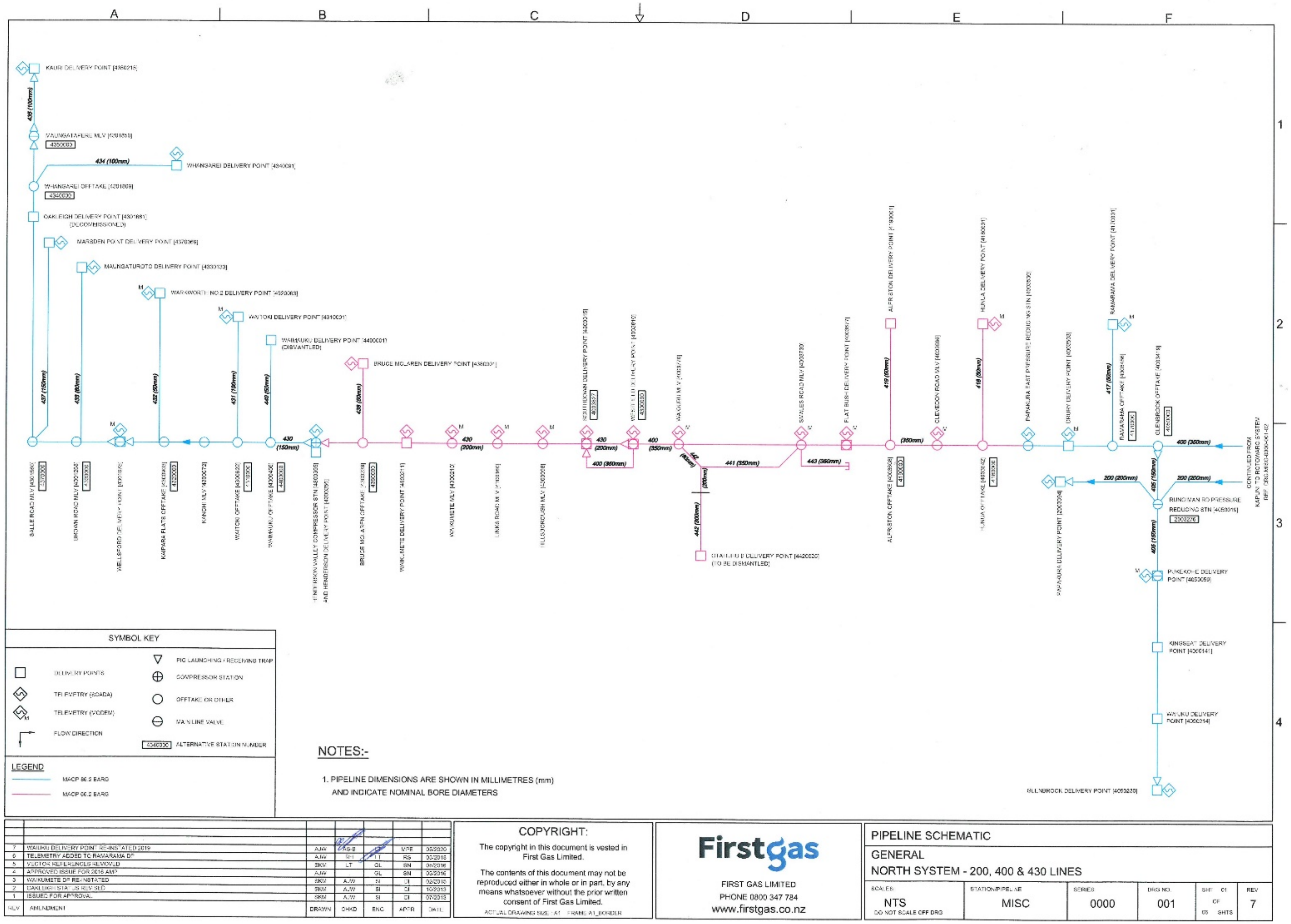


Figure 23 Kapuni, Rotowaro and Morrinsville System

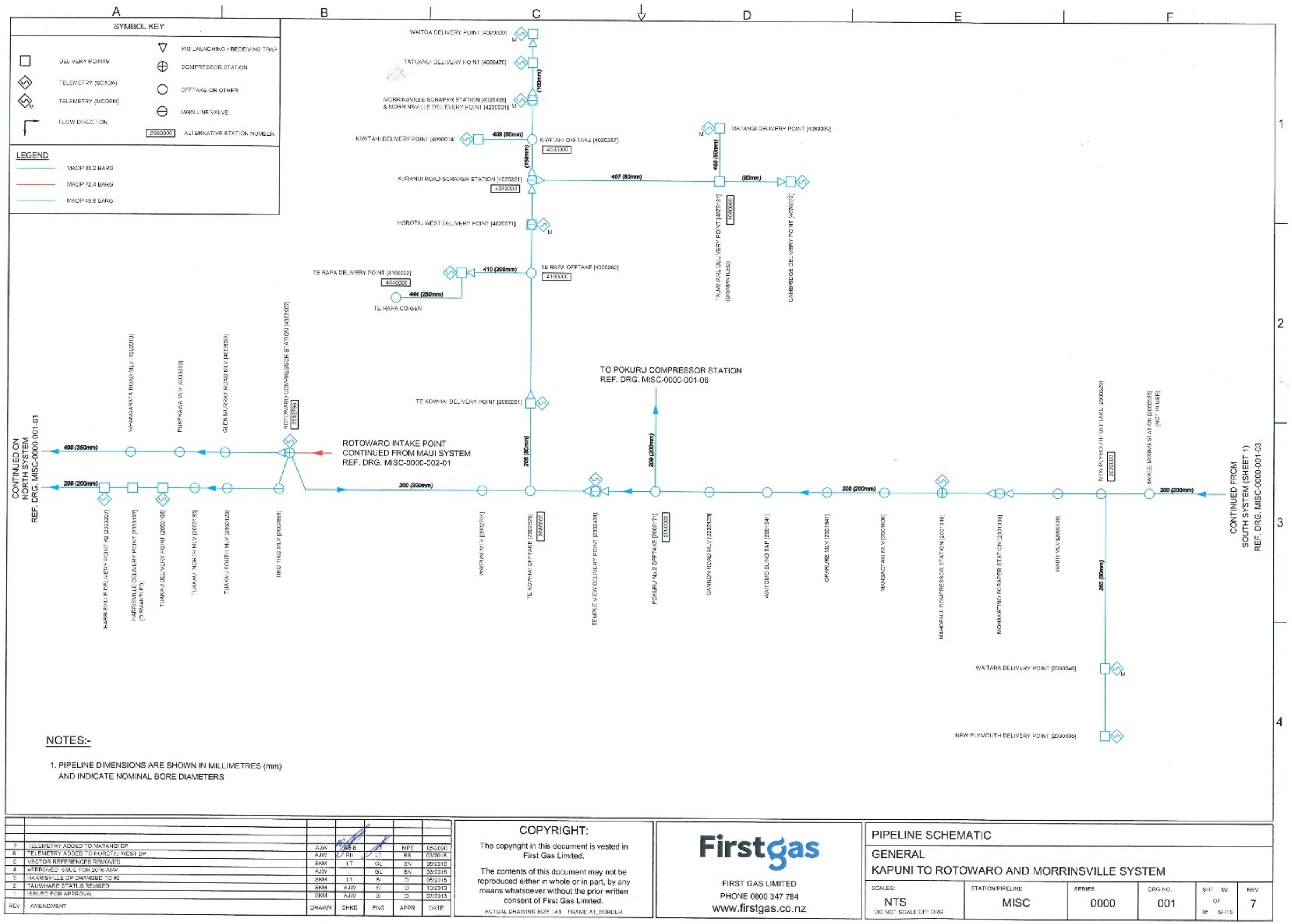


Figure 24 South System 1

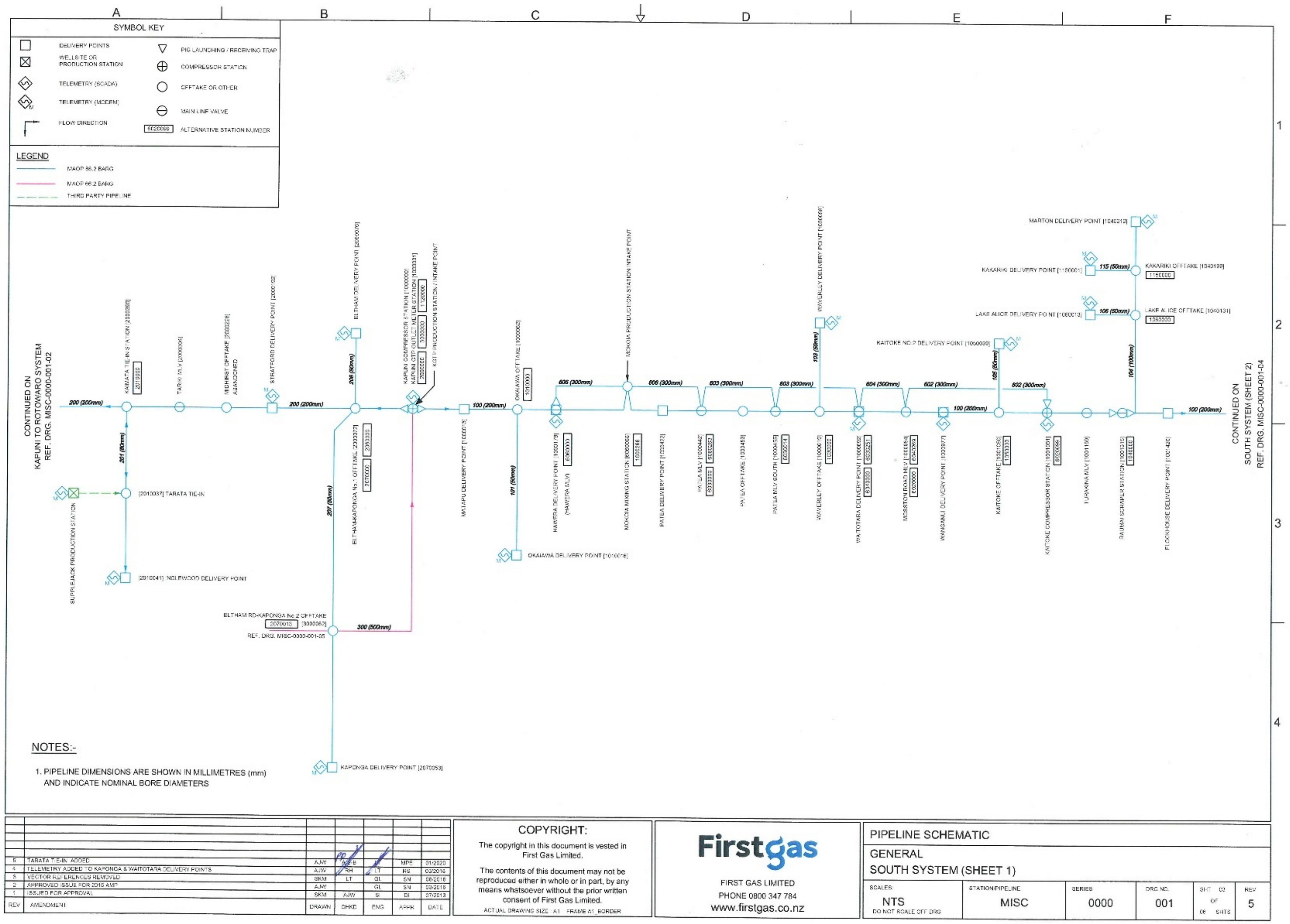


Figure 25 South System 2

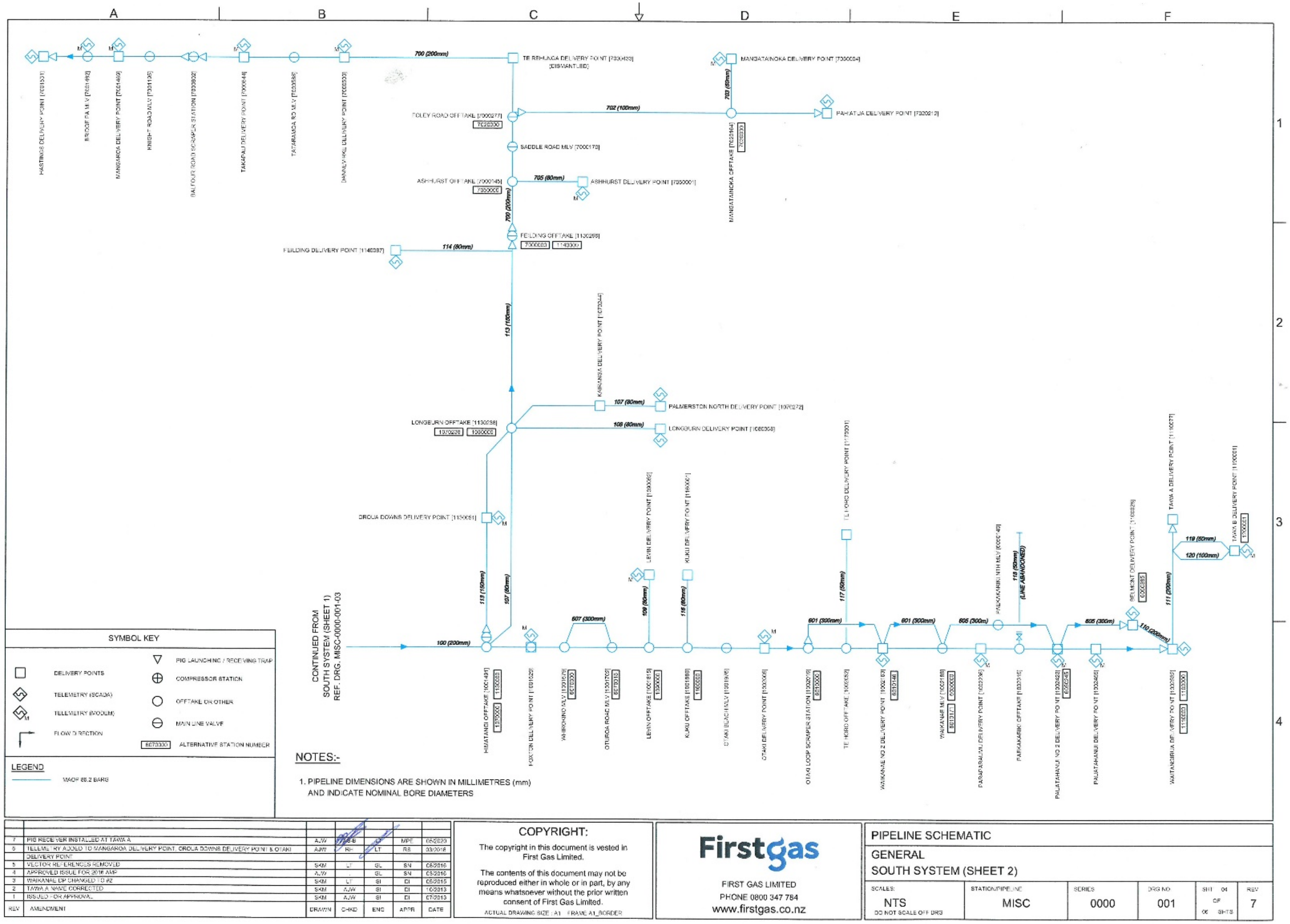


Figure 26 Frankley Road System

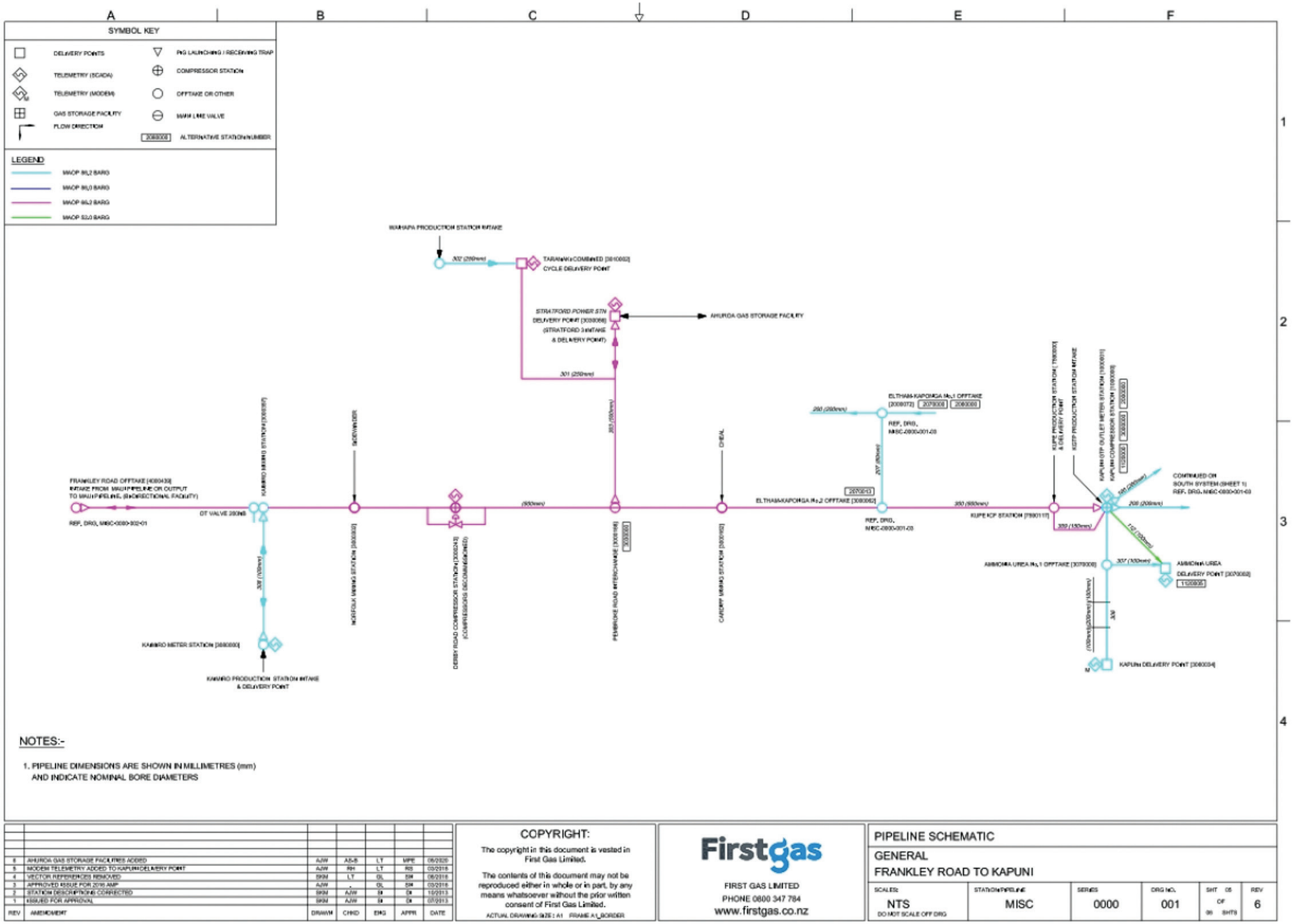


Figure 27 Bay of Plenty System

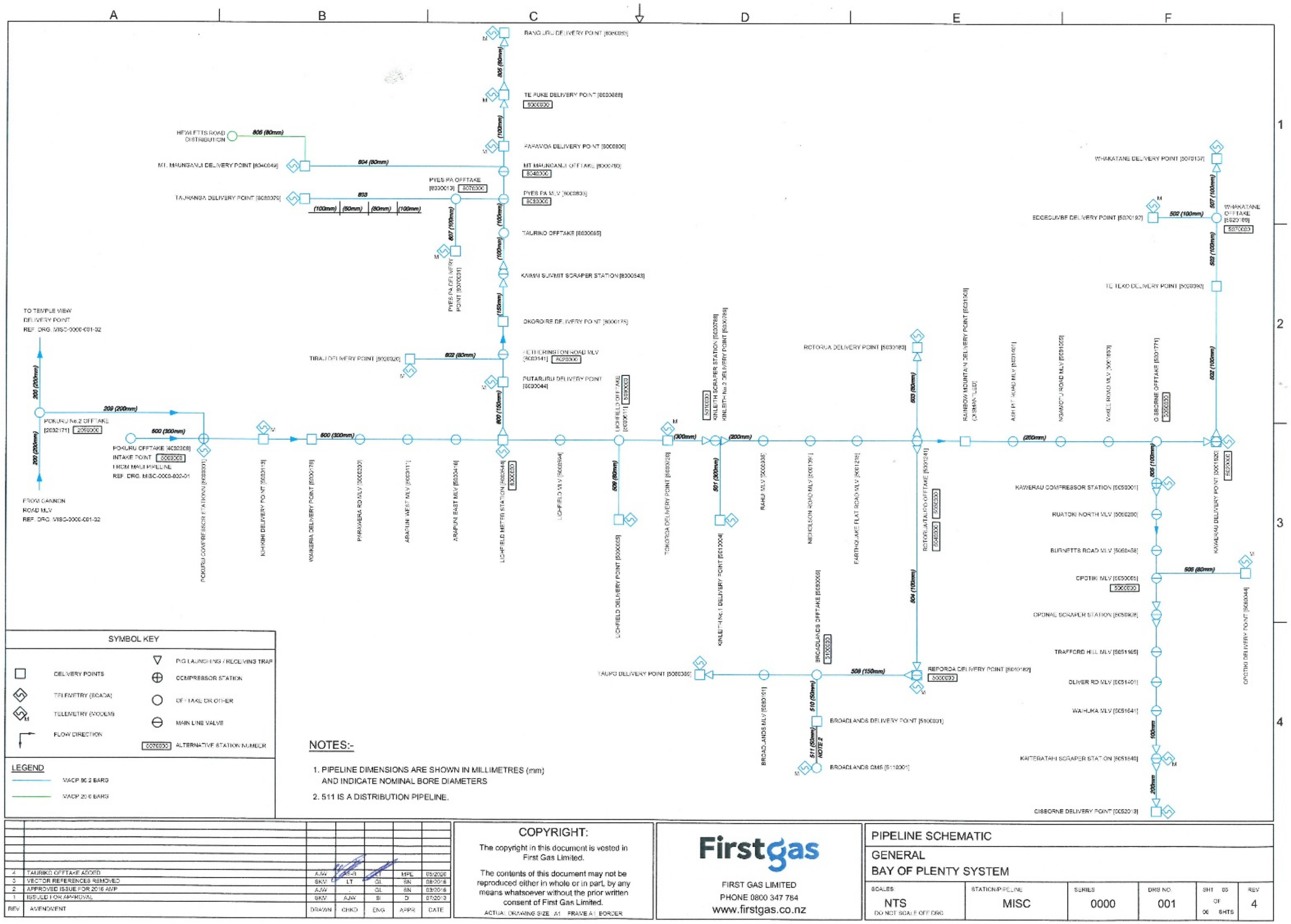
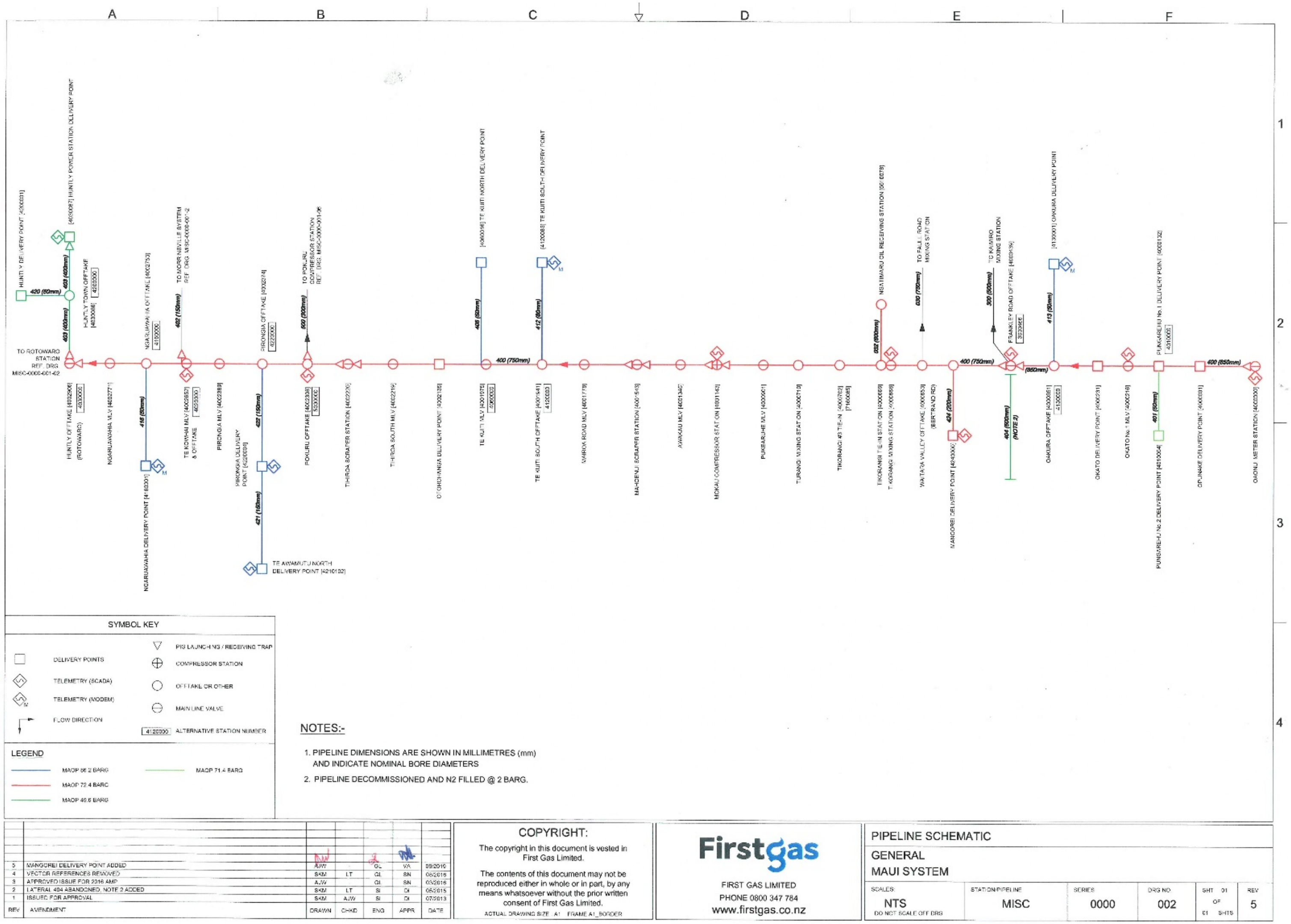


Figure 28 Maui System



APPENDIX F: SYSTEM DEVELOPMENT

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

- **Consumer connections:** expenditure to connect a new consumer to our 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 we can meet demand on our 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.

We are aware of a number of potential consumer connections that may eventuate within the next four years of the AMP planning period. These are summarised by sector in the Figure 29, which also indicates when the expenditure may occur. At this stage, no provision is made in our 10-year Capex forecasts for any specific project expenditure but a general allowance had been made in this category, based on historical expenditure.

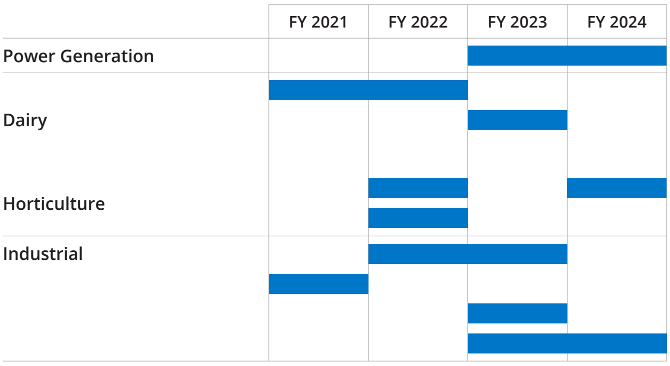
Firstgas forecasts anticipated expenditure throughout the planning period. Growth in any of the above sectors is subject to a range of influences, including:

- The general economic outlook
- 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
- The availability and price of gas

to name just some. These factors often impact on the timing of our forecast expenditure and result in that expenditure being "lumpy" rather than evenly spread. Forecast opportunities may also fail to materialise while other unforeseen prospects eventuate instead. 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**.

Figure 29: Depicting First Gas sector growth forecast



Power generation sector

All the consumer inquiries received in recent years have related to gas-fired peaking plant. This supports the view that gas is increasingly seen as a support for the growing base of renewables generation. Key players in the electricity industry consider that more such plants are required to back up the less reliable renewable sources such as wind and hydro-electric. Wind generation and hydro-electric generation tend to be affected by seasonal weather impacts and the impact from climate change (availability of wind and water).

One new delivery point was required in 2019. Todd Generation built a natural gas fired peaker power plant at Junction Road in Taranaki. This plant was commissioned in 2019, requiring a new delivery point to be built. Other opportunities are less mature.

Direct use of gas

Dairy processing

The interest amongst dairy companies in ceasing to use coal has unfortunately not yet resulted in their companies converting to gas. That is despite the fact that, of the four principal opportunities (in the North Island), in two cases existing gas infrastructure would be sufficient to deliver the gas required.

In the other two cases, transmission capacity limitations mean that significant investment in the transmission system would be required to enable the conversions to gas. Firstgas continues to work with those parties to identify a viable investment option that would make gas available.

Transmission capacity limitations mean that some dairy operators cannot access gas at present. First Gas is actively working with those parties to identify a viable investment option that would make gas available.

The key reasons for converting from coal to gas are well known and compelling. However, the largest operators in the dairy sector still using coal have been reluctant to commit to gas. In the case of Fonterra, biomass is being actively pursued as a substitute for coal.

Significant activity by non-traditional players and new entrants continued in relation to infant formula production for export. Synlait started up its major new greenfield plant at Pokeno in 2019, its first North Island manufacturing plant and the first of its plants to use gas. Further expansion at Pokeno is likely, either by Synlait or by the previous infant formula manufacturer there, Yashili. Firstgas is also working with another company planning a plant in the southern Waikato, which will use gas to provide process heat. In that case, a greenfield interconnection and delivery point will be required.

Horticultural

Glasshouse operators have been a large market for natural gas for over 20 years. In some of the largest glasshouses, CO_2 from the combustion of gas for heating is used to enhance crop growth.

One of the largest existing operators increased its glasshouse area significantly in 2019 and has sufficient land for a substantially greater expansion. Part of that expansion is likely to occur within the current planning period. That will require investment in the North System, mainly for a new pipeline but also for a delivery point upgrade.

Another significant glasshouse operator converted to natural gas from LPG in 2020. This conversion required a new delivery point to be built, at Waiuku.

Industrial

Large greenfield industrial (non-dairy) consumers have been few and far between in recent years. Most industrial growth has occurred on distribution networks, where individual consumers are usually not visible to us.

An inquiry for the largest industrial load we have seen in some years is expected to come to fruition towards the end of the current regulatory period. A section of existing pipelines was recently relocated to make way for the plant to be built. A new delivery point will be required to supply the plant, via a new distribution network in the area.

A major and long-established consumer who undertook a significant expansion in 2018-19 recently inquired about the availability of transmission capacity to fuel further growth. Pipeline capacity is sufficient but an upgrade of the existing delivery point would be required.

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
- Cater for organic load growth or changing consumer demand in existing areas.

Planning Principles

Our gas transmission system is regulated under the *Health and Safety in Employment (Pipelines) Regulations (1999)*, that 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, we design, operate and maintain the transmission system 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 our 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 our Transmission System Security Standard, which includes requirements set out in the *Critical Contingency Management Regulations*
- Consumers' reasonable gas supply (hence transmission capacity) requirements 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
- 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, the more scope we have to optimise design and procurement, and maximise synergies within Firstgas.

For new prospective loads, we undertake growth investments 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 our 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 our Transmission System Security Standard (see **Appendix G**)
- Supply to new developments or areas requiring gas connections
- Supply to existing connections requiring increased capacity

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 we anticipate consumers' needs so that, by timely investment in additional capacity, we avoid potential shortfalls of capacity, or breaches of our security criteria.

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

Our 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 we identify a shortage of uncommitted operational capacity at a delivery point, we will consider investing to increase capacity. This will consider 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 from a heavily-loaded to a less heavily-loaded gate station
- Potential for a change in delivery pressure to alleviate the limitation
- 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
- 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 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 *Gas transmission system security standard* requirements (defined in GTS-01, refer to **Appendix G**).

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: GAS TRANSMISSION SYSTEM SECURITY STANDARD

The purpose of our *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 forecast 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 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 asset performance.

G.1 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 First Gas transmission system, under all reasonably anticipated operating conditions.

G.2. 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 bar g. 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.[9] 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.

G.3 PURPOSE

The System Security Standard fulfils three key functions, by providing:

1. A clear measure for the minimum acceptable transmission system output performance, allowing easy identification of areas where attention may be required.
2. A clear design standard that identifies when investments may be required to augment the transmission system capacity.
3. A clear means of communicating to internal and external stakeholders the level of service they can reasonably expect from the First Gas transmission system. The System Security Standard sets the high-level design requirements for the transmission system to ensure that gas injected 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 of more of the system requirements discussed in Section 3 can no longer be met.[10]

The standard does not refer to the technical and safety aspects of transmission system asset performance.[11]

9. At some receipt points, First Gas owns the metering system that monitors and quantifies the flow of gas into the Transmission System.
10. Alternatively, First Gas 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 First Gas to recover the cost of reinforcing the transmission system at an appropriate rate of return.
11. The First Gas transmission system is regulated under the Health and Safety (Pipelines) Regulations (1999), which requires that the pipelines should be issued with a Certificate of Fitness by an independent Certifying Authority. In order to meet the requirements for Certificate of Fitness, First Gas 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.

G.4 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 under the Regulations. One of the obligations of the CCO is to declare a Critical Contingency when there is a likelihood or actual breach of one or more thresholds set in First Gas' ***Critical Contingency Management Plan (CCMP 08867)***. First Gas' 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 ***CCO Communications Plan*** (document CCO-003) is also prepared in accordance with the Regulations and describes the communications between the CCO and First Gas 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, taking into account the peak profile of gas demand and the operating environment of the asset.

A ***pipeline system*** refers to a part of the overall First Gas 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);[12]
- 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 First Gas's gas demand forecasting methodology;[13]
- 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.

G.5 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.

G.6 PHYSICAL SYSTEM CAPACITY

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

a) **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);

b) **Rotating equipment** – the maximum design gas flow rate or pressure levels (inlet and output) shall not be exceeded;

c) **Delivery point components** (including heaters, valves, metering systems, regulators, etc.) – under stable operating conditions the design capacity of any component shall not be exceeded.

12. Asset redundancy is covered in Section 1.8 of this System Security Standard.
13. First Gas' demand forecasting methodology is described in the First Gas Transmission Asset Management Plan.

G.7 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:

a) The minimum operating pressure defined under the CCMP requirements set out in the Regulations R25(1)(a) for that specified point;[14] or

b) The minimum contractually agreed pressure that First Gas has to 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 4 below.[15] 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.

Table 4: 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	5 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
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).[16]

G.8 COMPONENT REDUNDANCY LEVELS

The following minimum redundancy levels are required for the various components making up the gas transmission system:[17]

Table 5: Component redundancy levels

ASSET TYPE	REDUNDANCY LEVEL
Pipelines	N
Rotating equipment[18]	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

a) N+1 redundancy for rotating equipment at customer connections is not required, unless specifically contracted for.

b) N+1 redundancy for rotating equipment is not required at low-demand compressor stations. On the First Gas Transmission network, this includes Kawerau Compressor Station.

c) 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 Compressor Station via the 200 pipeline, hence, Pokuru Compressor Station is considered to meet the N+1 redundancy standard.

14. R25(1)(a) specifies the permissible limits for thresholds to be specified in the Critical Contingency Management Plan. This is specified as a range. First Gas Ltd 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.
15. With the exception of Bertrand Road Delivery Point on the Maui pipeline, over-pressure situations at delivery points is not considered a design standard, as these are unlikely to arise and, in addition, protection against over-pressure is provided at all delivery points.
16. 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.
17. 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.
18. 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.

APPENDIX H: ASSET MANAGEMENT

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

- **Asset Management Framework:** describes our approach to ensuring alignment between our corporate objectives and our day-to-day asset management activities.
- **Asset Management System:** describes the components of our asset management system and provides an overview of the key elements.
- **Performance Measures:** sets out the overall asset management performance objectives.
- **AMMAT and Benchmarking:** discusses the outcome of our Asset Management Maturity Assessment Tool (AMMAT) review and other benchmarking exercises.

H.1 ASSET MANAGEMENT FRAMEWORK

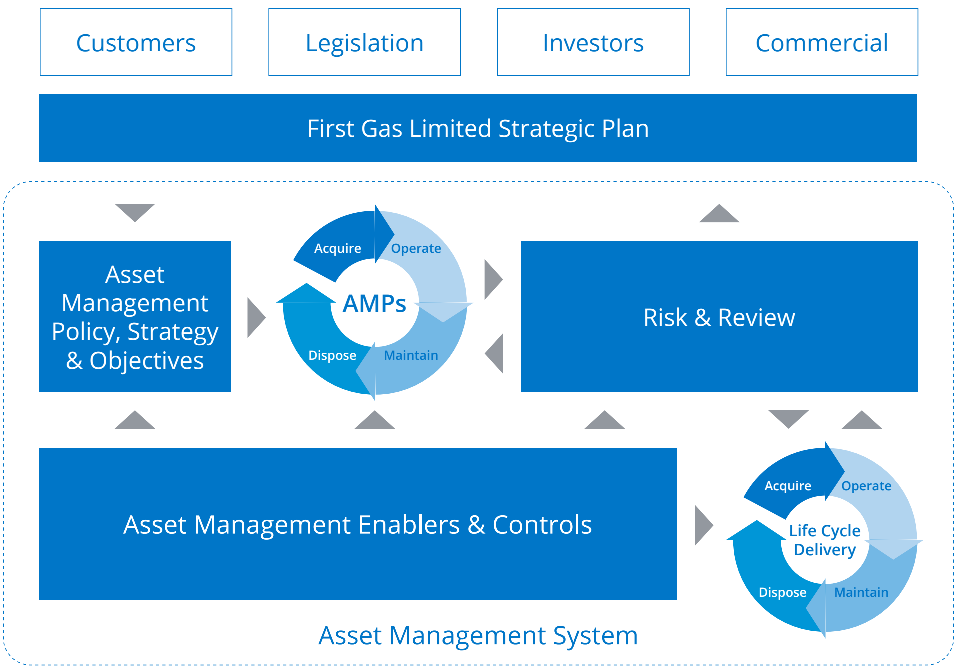
Our asset management framework is primarily designed to support the delivery of our corporate objectives and stakeholder needs and demonstrates how they link with the components of the asset management system.

The Strategic Plan is the starting point for the development of the primary elements in the asset management system, the Asset Management (AM) Policy, Strategy, Objectives and Plans. These, in turn, direct the optimal combination of life cycle activities to be applied across the portfolio of asset systems and assets (based on their criticality, condition and performance).

This connective thread is a key feature of our asset management framework, providing clear "line of sight" from the organisational direction and goals down to the individual, day-to-day activities. Similarly, looking upwards, the monitoring of asset problems, risks and opportunities should provide the factual basis for adjusting and refining asset management strategies and plans, through a process of continuous improvement and should inform stakeholders by way of adjustments to the Business Plan.

The interaction between our strategic plan and asset management system is shown below.

Figure 30: Overview of asset management framework



H.2 ASSET MANAGEMENT SYSTEM

In this section, we explain our asset management system. An important function of this system is linking our corporate objectives and stakeholder needs to specific asset management approaches through our Asset Management Policy.

Our asset management system aligns with the requirements specified by *ISO 55001* and seeks to reflect good practice. This system includes the following components:

- **Asset Management Policy, Strategy and Objectives:** aligns our asset management approach with our corporate objectives. Our 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 our asset lifecycle model and aligns our 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 & Review:** explains our approach to managing risk on our network, including how we identify and classify risk, and how we take appropriate actions to manage the risks that we identify.
- **Life Cycle Delivery:** provides an overview of our approach to managing our gas transmission asset.

H.2.1. Asset Management Policy, Strategy & Objectives

Asset Management Policy

The Asset Management Policy provides a high-level statement of our asset management direction, principles and guiding objectives. The policy provides direction for our asset management decisions and everything we do to manage our assets should map back to the policy.

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

The policy also sets out key asset management principles that flow through our processes and systems. This is important to ensure the necessary linkages between our objectives and what we are aiming to achieve through our asset management practices.

The policy is set out below and has been approved by the Firstgas Board and communicated to all staff.

Asset Management Policy

Firstgas' Asset Management Policy is to effectively manage the gas distribution and transmission 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 Firstgas' Mission:

To deliver stable and predictable financial performance through providing safe and reliable gas pipeline and network services.

To deliver on our Asset Management Policy Firstgas 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 First Gas 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

Our Asset Management Strategy or Strategic Asset Management Plan (SAMP) is incorporated across the AMP (reflected primarily in our discussions in the system development and lifecycle delivery sections) and other internal asset planning documents. It has a forward outlook of two years and is reviewed formally on an annual basis aimed at:

- Identifying our desired future performance.
- Identifying our current performance.
- Developing objectives and improvement actions to deliver the required performance.

The AMMAT gap analysis and other external and internal reviews demonstrate that while we have improved in a number of areas since the last AMMAT was completed in 2018, we still have opportunities for improvement. Our asset management improvement programme includes a number of initiatives aimed at achieving improvements in asset management and long-term performance of our assets. These include:

- Embed and evolve our asset management system. Key elements include:
  - Asset Management plans
  - Capital expenditure
  - Maintenance optimisation
  - Asset risk
  - Planning and scheduling
  - Project management
- Further development of our asset health indicators and criticality approaches.
- Development of technology to provide real time dashboards for asset health.
- Further development of Maximo, Firstgas' Enterprise Asset Management (EAM) system to support changes with elements in the asset management system
- Use of technology to collect and provide insights into asset performance and condition.

Over the next few years these initiatives will result in further improvement of our asset management practices, supported by enhanced asset information systems.

Asset Management Objectives

Our Asset Management Policy provides a suite of asset management performance objectives against which we can measure our performance. These objectives are related to our performance measures discussed later in this appendix. The objectives are:

- **Safety:** prioritise the integrity of our assets to ensure the safety of the people and places affected by our 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 our investment plans to stakeholders, particularly the communities that host our assets.
- **Value:** operate in a manner that optimises the long-term financial outcomes for our shareholders.
- **Decision making:** balance the needs of competing objectives in a consistent and transparent manner.

H.2.2. Asset Management Plan

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

This AMP has been developed with oversight and input from our 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 special Board meeting for approval prior to publication.

Key Assumptions

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

- The present gas industry structure will broadly remain the same. For example, we have 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. We make decisions on what work to outsource 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 we aim to increase the use of our gas transmission network, we have adopted prudent 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 our operational and investment decisions – for example, through structural changes to the regulatory institutions or the regulatory mechanisms currently in place that allow us to recover our 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, we have noted the source.

Financial Authority

Each project within our AMP is approved based on our 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 which managers are allowed to authorise expenditure. This is reviewed annually.

Table 6 below sets out our DFA levels.

Table 6: Delegated Financial Authority Levels

GOVERNANCE LEVEL	FINANCIAL AUTHORITY CAPEX ($000)	FINANCIAL AUTHORITY OPEX
CEO	$2,000	Budget
COO	$500	$500
Engineering and Projects Manager	$400	$400
Transmission Operations Manager	$100	$100

Challenge Processes

The material included within the AMP reflects our system development plans, life cycle delivery plans, customer connections forecast, and our 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 Firstgas' 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.2.3. Asset Management Enablers And Controls

This section describes how we ensure appropriate oversight and challenges are in place during the development and execution of our 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, prioritize, plan, budget, execute, control, and closeout capital expenditure projects and major operational expenditures.

- **Pipeline management system:** demonstration of compliance for audit and certification purposes, but also 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 our staff performing design, construction, operations or maintenance on our transmission system meet the competency requirements as specified by our 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, prioritize, 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 chosen to adopt AS 2885 (the Standard) as the guiding document for maintaining appropriate standards of safe and sustainable operational practice.

Section 2 of *AS 2885.3:2012* 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 intention of the PMS Manual is to demonstrate that the GTB management system fulfils the requirements of the Standard. This is achieved by a combination of commentary on the various required activities and reference to the relevant procedures, instructions or other documents that control those activities. The PMS Manual is, therefore, a bridging document providing a map between the Standard and the control processes in place. Where the mapping process identifies any gaps, or opportunities for improvement, action plans will be developed to implement required changes. As changes are implemented, the document will be updated to reflect them.

Not withstanding the statutory obligation for compliance, the GTB regards the Standard as representative of good industry practice and an aid to achieving Firstgas' own objectives in the areas of safety, environmental assurance and security of supply. Firstgas takes very seriously its own duty of care and obligation towards all its stakeholders, whether employees, customers or wider society and is fully committed to the safe, sustainable, reliable and efficient operation of the transmission system.

The PMS manual serves as a demonstration of compliance for audit and certification purposes, but also 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 7: PMS structure

MEASUREMENT AND EVALUATION	MANAGEMENT	PLANNING	IMPLEMENTATION	CONSULTATION, COMMUNICATION AND REPORTING
Data acquisition and analysis	Policy and commitment	Safety management study	Commissioning plan	Landowners
Accident / incident investigation and reporting	Organisational structure	Hazard identification and mitigation	Operating procedures	Emergency authorities
System audits	Responsibilities and accountabilities	Abnormal operating conditions	Environmental management plan	Regulatory authorities
Corrective and preventive action	Training and competence	Emergency situations	Permit to work system	Government agencies
	Resourcing		Pipeline integrity management plan	Community
	Change management		Maintenance and repair plans	Other stakeholders
	Management review		Emergency response plans	
			Abandonment plan	
			Records management plan	

Competency and Training

All our staff performing design, construction, operations or maintenance on our transmission system must meet the competency requirements as specified by our training matrix.

As a part of the contractual agreements with our contractors, 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. We align training requirements 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.2.4. RISK & REVIEW

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

Key Risk and Review elements include:

- **Risk Management:** our core processes designed to manage existing risks, and to ensure emerging risks are identified, evaluated and managed appropriately.
- **Contingency Planning and Response:** ensures that we are prepared for, and can respond quickly to a major incident that occurs or may occur on our 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.

Risk Management Policy

Effective management of risk is central to the growth and success of Firstgas. 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 Firstgas 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.

Firstgas 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;
- 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;
- Governance processes with regular updates and reports to the Board and Executive Management Team;
- 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 our day-to-day asset management approach.

Our asset management information systems and our core processes are designed to manage existing risks, and to ensure emerging risks are identified, evaluated and managed appropriately. Our approach is to seek specific instances where features of our network which should make us resilient, do not suffice or apply. In particular, the following assessments are used:

- **Prioritise safety:** we prioritise those risks that may impact the safety of the public, our staff and service providers.
- **Ensure security of supply:** our works development and lifecycle management processes include formal evaluation of our assets against our security criteria.
- **Address poor condition/non-standard equipment:** our 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:** our 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:** we use structured risk capture and management processes 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 our 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 our top operational priorities.

The gas transmission business unit has a risk management system that is outlined in a controlled document.[19] This procedure outlines the minimum requirements and ensures consistency in risk management by our business.

As risk severity is defined by the combination of likelihood and consequence, our 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. Rather, it is about fully appreciating and recognising all the risks the business carries, and balancing them to take advantage of potential opportunities in an informed manner.

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

Contingency planning and response

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

- **Multiple control options:** we have alternative control and emergency management capability available in the event that our primary site is disabled.
- **Emergency response plans:** we have well tested response plans and demonstrated capability to manage significant natural events and widespread damage to our system.
- **Business continuity plans:** we have structured business continuity plans in place to ensure that the functional support aspects of our business are resilient and can support ongoing operations.

Emergency response plan

To ensure that we are prepared for, and can respond quickly to a major incident that occurs or may occur on our 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), we 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". We are also required to have plans regarding how we will function during and after an emergency and to participate in the development of a CDEM strategy and business continuity plans.

We participate in CDEM emergency exercises and area meetings on a regular basis to ensure CDEM protocols are understood, as well as to test aspects of our 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, as well as 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

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H.2.5. Life Cycle Delivery

This section explains our approach to managing our gas transmission assets. We use a lifecycle-based asset management approach. We discuss this approach and the main activities it entails during the planning period.

Key Life Cycle Delivery elements include:

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

H.2.6. Asset Lifecycle Management

Safety is the key consideration in the design, construction and maintenance of our gas transmission system. We manage our assets in accordance with relevant acts, regulations and industry standards.[20] Our transmission assets are designed and built to deliver gas to service levels set out in our *Security Standard (GTS-01)* and to meet the needs of our customers.

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

The asset lifecycle approach we use includes the following main activity phases:[21]

- **Acquire:** this includes investments in new (or larger) assets to ensure we can meet demand on our network at appropriate security levels
- **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).

We also discuss asset relocation works where existing services need to be moved as a result of the activities of other utilities or developers.

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 our 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.

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.

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

The combination of asset management processes, policies and criteria align with our strategic drivers. These drivers translate into long-term asset development, maintenance, and renewal approaches. The following factors are taken into consideration when making lifecycle management decisions.

Safety:

- Ensure the safety of the public, employees and contractors at all times.
- Ensure our inspection regimes effectively identify safety hazards.
- Protect the integrity of our network and assets by monitoring the activities of third parties.

Security and Reliability:

- Ensure the pipeline system is designed, operated and maintained to the required standard to provide the agreed level of service.
- Maintain an informed and justified view of the expected life of all asset types based on asset information, industry practice, experience and knowledge.

20. In particular the *Health and Safety in Employment (Pipelines) Regulations 1999* and the *AS 2885* standard require Firstgas to operate and maintain a safe and reliable gas transmission asset.
21. Our approach also includes construction and disposal phases.

- Maintain a feedback cycle from maintenance activities to inform current asset information and to continually refine maintenance standards.
- Maintain existing assets in good and safe working order until new assets are built or they are no longer required.
- Ensure pipe system operation is reliable.

Environment:

- Preserve the environment by operating in a manner that mitigates environmental risks.

Compliance:

- Comply with relevant acts, regulations and industry standards.

Communication:

- Ensure an appropriate level of response to customer concerns, requests and enquiries taking into account any pricing and regulatory trade-offs.
- Minimise landowner disruption when undertaking work.

Value:

- Strive to achieve the optimal balance between capital and operational costs.
- Ensure pipe system investments and operating activities are prudent and efficient.
- Strive for continual innovation and efficiency improvements in our lifecycle activities.

Decision Making:

- Coordinate asset replacement and new asset creation programmes.
- Maintain a business funding approval process aligned to the anticipated replacement or decommissioning of assets.
- Apply innovative approaches to solutions, development and projects execution.

H.2.7. 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 we look to replace or renew them.

- **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, we also assess other alternatives, 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 our assets. From this evaluation, we are able to schedule asset renewals. 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 taken into account 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 our inspection regimes effectively identify safety hazards. We also focus on protecting the integrity of our network and assets by monitoring and managing the activities of third parties.

A Safety Management Study (SMS) of the assets was conducted in 2016 in accordance with AS 2885. Further studies are to take place periodically at a maximum of five-year intervals, or when any significant change to the system or operations is made.

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

Safety-in-Design

We are committed to ensuring that our operations do not put our employees, contractors or the public at risk. This extends to safety being a key focus of the design phase of the work we do. 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 our work practices.

Such changes can include:

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

The system is designed to meet our *Transmission System Security Standard*, which 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.

Legislation and Standards

Our 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 our 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 our personnel and others involved in the design, construction and maintenance of our 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/NZS 3000:2007* Electrical installations. This refers to:

- *AS/NZS 60079.14 – Explosive atmospheres – Electrical installations design, selection and erection.*
- *AS/NZS 60079.17 – Explosive atmospheres – Electrical installations inspection and maintenance.*

Asset Health and Criticality

We assess asset condition, performance and risk to determine the Asset Health index. The health index helps determine whether an asset requires planned repairs, replacement or renewal.

These assessments are based on:

- Results of field surveys, inspections, tests and defect work schedules.
- Analysis of data associated with equipment condition e.g. compressor oil analysis, vibration monitoring of rotating equipment and water bath heater water sampling.

Maximo improvements this year is to develop, test and deploy a proof of concept asset health tool. Firstgas and a third party supplier have worked collaboratively in developing a proof of concept using the Maximo Asset Health Insight (MAHI) tool. The project aims to deliver a centralised interactive asset health data visualisation, centralises and structures the score of data sources, flexible and configurable, and fully integrated to Maximo data and information. Meeting these objectives are fundamentally essential, enabling us to drive our business improvements. The development of Asset Healt tool into production environment has been approved, and it is underway.

MAHI is an add-on tool to Maximo, which brings together data from different sources such as operation, maintenance, engineering and asset management in one place. This enables users to obtain clear and well-founded insights into the health of their assets.

The Asset Health tool forms part of a bigger picture and fits in with our Asset Management Plans to give a clear line of sight between strategy, risk, condition and management of our assets. In addition to condition, other drivers for determining the asset health index are based on factors relevant to the particular asset and may include the following:

- They are irreparably damaged.
- The risk of asset failure as determined through a failure-mode effect analysis (FMEA).
- Reliability and performance has become unacceptable.
- The operational and/or maintenance costs over the remaining life of the asset will exceed that of replacement.
- Assets become obsolete and hence impossible or inefficient to operate and maintain.
- Factors affecting the rate of degradation such as the environment.
- Failure and outage rate – historic and projected.
- Known defects in certain assets or groups of assets.
- Issues affecting acceptable life such as compliance with safety or environmental regulations.
- Asset age and the life expectancy of the asset fleet.

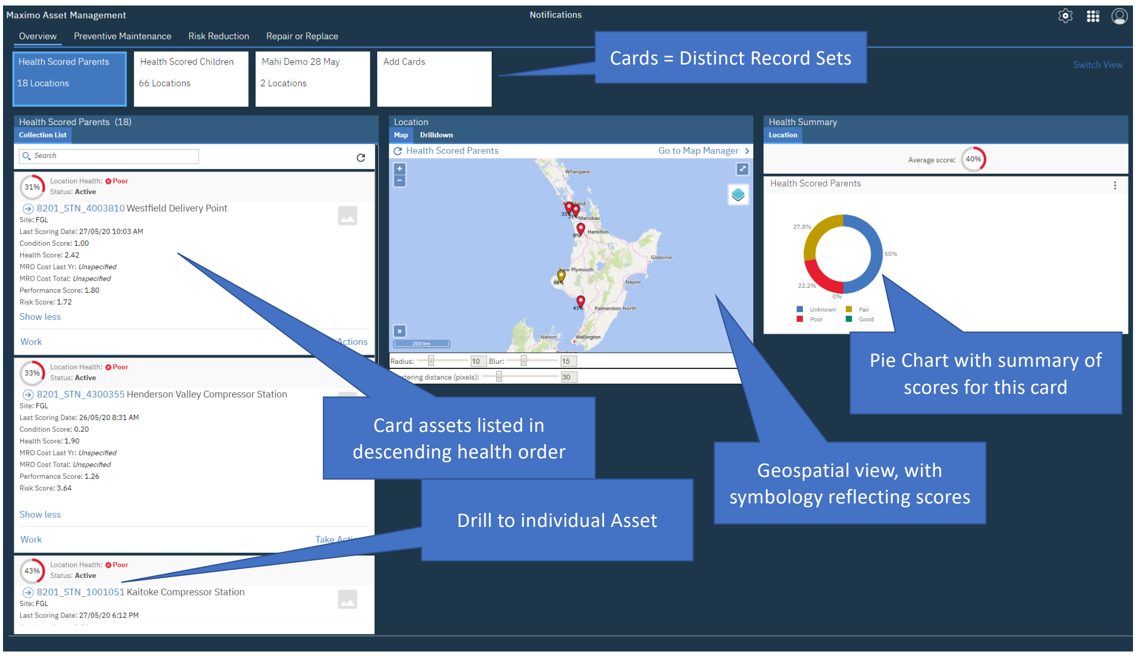
Where practical, all ARR investments are made taking into account the asset health index and the asset criticality which is an indication of the importance of the asset.

Overall lifecycle cost

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

- Estimation of maintenance costs over the remaining life of the asset relative to cost of replacement.
- Determination 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.

Figure 31: Asset Health dashboard and parameters



Summary of ARR capex

Once an asset is identified for replacement or renewal, our 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.

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

H.2.8. Relocations

We relocate existing services 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 our assets may require us to relocate the assets. Relocations are identified following third party works notifications. Typically, asset relocations projects are predominantly funded through capital contributions by the third parties requesting the relocation.

Examples of relocations work are outlined below:

- **Ports of Auckland:** will undertake a development in the northern Hamilton area. In order for the development to take place, our high-pressure pipeline needs an increase in depth and to be reinforced.
- **200 Line Ladies Mile:** New Zealand Transport Agency has a significant ongoing works project on State Highway 3 (SH3) to widen a straight stretch of road, located North-East of Awakino in the Waikato, known as Ladies Mile. A realignment using more robust pipeline materials is required.

H.2.9. Maintenance

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

Maintenance approach

Our maintenance approach is designed to ensure that our assets safely achieve their expected life and performance levels. We use information obtained in the course of maintenance work to guide our future maintenance programmes and to inform renewal decisions.

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.

We have a comprehensive suite of asset maintenance standards that describe our approach to maintaining our 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.

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

- Regularly review the effectiveness of routine maintenance for each asset type and update our maintenance standards and activities as required to deliver optimum performance.
- Regularly review the effectiveness of our monitoring programme 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 our assets, and taking appropriate action to ensure the integrity of our network is not compromised.
- Educate the public, landowners and customers through regular communication about the dangers of working near our network.

Activity drivers

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

A number of considerations are taken into account 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 our main reference for these activities. Other obligations fall into the category of good industry practice and are to be 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

Our 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, we have developed overarching maintenance programmes 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 our asset maintenance schedule.

Our 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 issue that is showing an increasing trend is urban encroachment on our 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 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 our 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 we categorise our maintenance work into the following Information Disclosure categories.[22]

- 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. We use ongoing condition monitoring 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.

22. We currently do not assign any expenditure to the ARR Opex category.

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 our 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 our maintenance routines as they become proven across various industries.

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

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 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 our corrective actions database or assessed, prioritised and assigned in the Asset Risk Register.

We use a pipeline integrity management software application for the management and analysis of pipeline condition data. The system employed is the Rosen Asset Integrity Management System (ROAIMS). This system has improved our ability to record and store data obtained from the routine maintenance and inspection of our 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 our Maintenance Strategy. This document describes our 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 our 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 our high pressure gas transmission system is subject to the requirements of the *HSE Pipelines Regulations*. As a primary means of compliance to these regulations, we have adopted *AS/NZS 2885*. As pressure vessels fall outside the scope of these regulations, we carry out inspection and maintenance of our vessels in accordance with:

- *AS/NZS 3788: 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 us to accurately assess 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 our renewal and maintenance investment can be continually assessed and refined. Due to the aging profile of our 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.

We take every reasonably practicable precaution 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

We have a mixture of insource and outsource approaches for field work delivery within Firstgas. We see this mixture as being currently 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 we have taken ownership for providing the resource internally.

We outsource some capital project construction and a number of other technical roles to a group of 'service providers'. We seek to build sustainable and effective relationships with them through appropriate commercial arrangements.

This approach enables us to keep core engineering competencies in-house while leveraging the expertise and resources of our service providers. While our approach has several benefits, it requires that we effectively align our respective aims and incentives

Maintenance Delivery

Asset inspections and maintenance work is delivered by our Transmission Operations and Specialist Services 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 work load 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.2.10. OTHER NETWORK OPEX

We incur additional Opex during the day-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.

Our overall Opex over 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 in including OATIS costs
- Outage planning and notification
- Production facility liaison

Compressor fuel

All our gas turbine and reciprocating engines, with the exception of the Henderson compressor station, are fuelled by gas. We purchase compressor fuel under an agreement with a gas retailer, following competitive tenders which we undertake 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 & Associated Activity

With regards to land management and activities in the area of our pipeline, 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.

Our Pipeline Integrity Team have formalised the process by which proposals for activities on or adjacent to our pipeline easement are considered. We then provide respond to enquiries 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 our 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 our pipeline routes, together with our high rates of discovery and reporting.

Some of the routine pipeline awareness techniques we use as a part of our pipeline safety awareness plan include:

- Signage replacement.
- Land owner 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.2.11. Asset Management Support

This appendix discusses the functions and capabilities that support our day-to-day asset management activities. It describes our:

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

H.2.12. Non-network Assets

This section discusses our non-network assets. It explains our approach to delivering IS capabilities and managing associated assets. It also discusses our other non-network assets (e.g. our buildings).

H.2.13. ICT Assets

We have implemented a number of systems since the initial transition to improve organisational capability: These include:

- X-Info Suite, a Land & Planning management toolset.
- Solufy Akwire, a field resource scheduling tool that interfaces with Maximo.
- ESRI ArcGIS for the transmission asset data so all our GIS data is now in the same system.

Project Server Online as the collaborative project management tool.

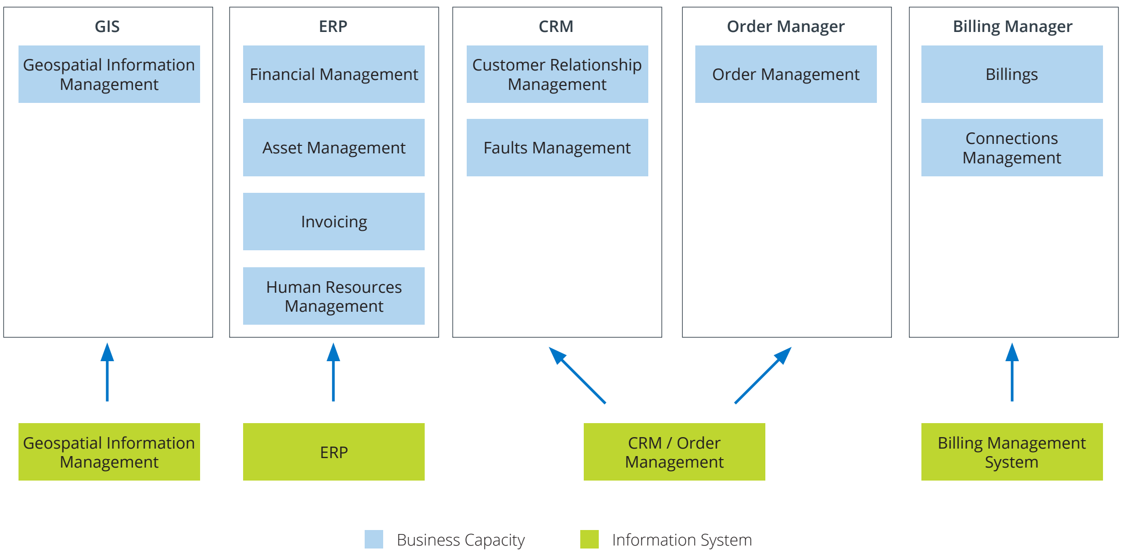
The ICT systems and functions include:

- **Core network related systems:** support capabilities that manage information directly relating to First Gas network assets and their operation and management.
- **Supporting network related systems:** are smaller systems that support capabilities that manage information that directly relates to our 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 32 illustrates the relationship between our business functions and processes – hereafter referred to as business capabilities – and our core network related systems.

We expect to continue investing over the next few years to ensure the systems are being used effectively and efficiently. We expect to invest particularly in information management strategies and digital workspace transformation.

Figure 32: Business Capabilities and Core Network Related Systems



H.2.14. Information and Data

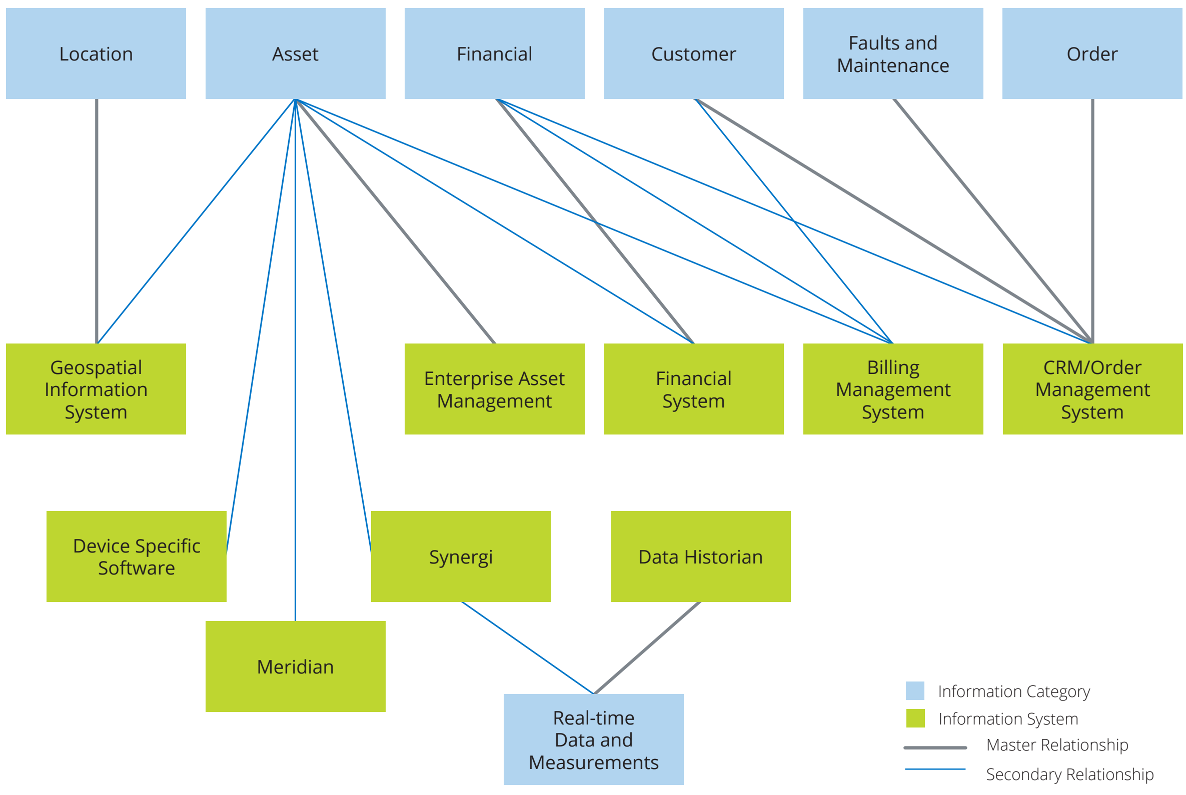
Our network and supporting network information systems manage data that is necessary for the effective day-to-day operation of our network assets and the ongoing planning activities relating to those assets.

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 our information systems are shown in Figure 33 below.

Figure 33: Information and Systems Relationships



Information Systems Strategic Plan (ISSP)

Our ISSP aims to ensure we develop capabilities enabling us to support our planned asset management changes over the planning period, including:

- Enhancing our asset management analysis capabilities
- Supporting increased work volumes on our networks
- Providing real-time information to customers, including through new information channels
- Enhancing the way we deliver works with our service providers

Over the planning period, we recognise that the range of available options to deliver ICT capability will shift and evolve rapidly. Our strategies and plans are designed to maximise flexibility in a changing environment.

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

Our architecture must be developed on industry accepted standards for cyber security in an increasingly connected communications landscape. Over the planning period we need to ensure that our 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 our systems are resilient, reliable and responsive, designed with multiple layers of redundancy matched to the criticality of the capabilities they support.

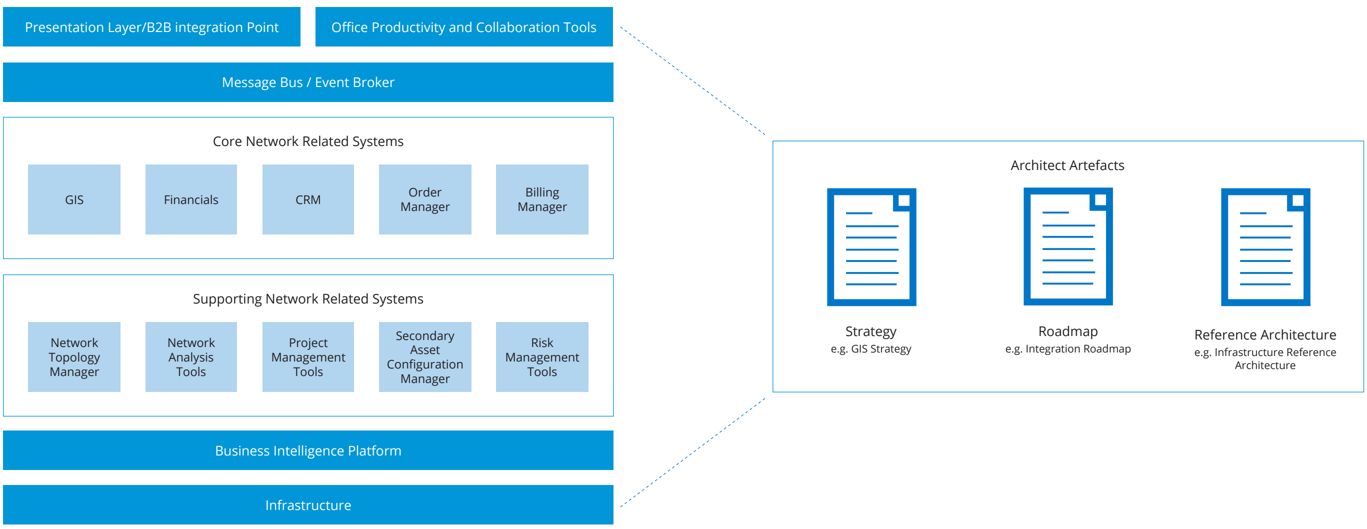
ICT Investments

This section describes our approach to investing in ICT assets that support our 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 our processes, technology and systems help deliver our asset management objectives.

Each component within our 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 34: 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 takes into account financial constraints such as total cost of ownership and IS asset depreciation.

Furthermore, our expenditure forecasts are informed by historical costs, expected unit cost, and price trends. We 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 we have assumed that software costs will progressively move from Capex to Opex as software providers shift to the software as a service model. We also assumed that hardware costs are likely to be stable over the next 10 years on a like-for-like basis.

We believe an uplift in ICT expenditure will be required over the first and fourth years of the planning period due to our investments in new systems. From year five, expenditure is expected to stabilise.

Main ICT Systems

Table 8: Key Systems

SYSTEM	DESCRIPTION
Microsoft Dynamics NAV	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 (Dynamics NAV)

Our 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. We selected Microsoft Dynamics NAV as our financial management system and implementation of this system occurred in FY2016.

We have moved some of the financial processes out of our EAM solution so they better align with business management processes and reporting requirements. These include:

- Inventory management.
- Procurement management.
- Inter-Entity Billing.

Enterprise Asset Management (EAM): Maximo

To meet our organisational objectives, we must focus on capturing accurate data at source and making information accessible to the business with tools that allow us to leverage value and improve our performance.

In line with our 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 our 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 our operational and engineering standards and supported by our 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.

Our EAM includes four management modules in an enhanced service-oriented architecture. It allows us to use asset information to achieve our customer & regulatory outcomes, increase our operational efficiency and to identify opportunities for disciplined growth and improvements in our 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 are 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)

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

Billing (Axos)

Our 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 us to better control billing processes without the systems becoming overly complex and costly. It will enable us to execute billing processes effectively and efficiently to achieve our customer and regulatory outcomes, increase our operational efficiency, to identify opportunities for disciplined growth and improve our 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 is planned over the next years. A replacement system has been formally selected, and this will be implemented to support the new Gas Transmission Access Code (GTAC) which was approved by the Gas Industry Company (GIC) in FY2019. The GTAC is a transformational strategic initiative for the New Zealand gas industry as once implemented, access to the transmission network will be under a single code. Currently access is either under the Maui Pipeline Operating Code or the Vector Transmission Code.

Training Manager

Our 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

Our 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.

Our asset data standards determine which assets are captured in our asset management information systems, what attributes of those assets are recorded, and what transactions we want to be recorded e.g. records of planned inspections, faults and defect data.

We gather and upload data in accordance with our standards, but we are responsible for processing the data or formulating maintenance plans or strategy on the basis of the data.

H.2.15. Other Non-Network Assets

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

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

Offices and Facilities

Our expenditure during the planning period mainly relates to the refurbishment of our 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

Our approach with vehicles is to buy our fleet; it makes better strategic sense to own a vehicle directly where certain towing ability is required or where specific plant equipment is required.

Minor Fixed Assets

All our employees are provided with a standard workstation setup that includes a desk, chair, storage, PC and communication equipment. We classify minor fixed assets 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.2.16. Non-Network Capex Expenditure Allocation Methodology

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

H.3. BUSINESS SUPPORT

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

H.3.1. Business Support Expenditure

We directly employ about 222 people across our gas businesses (who also support our distribution assets). We support the employment of many more field staff and engineers through our service providers. To support our asset management teams, we have a number of corporate support functions. These include customer management, finance, and ICT. These functions either directly or indirectly support the transmission side of our 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 our 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.

Our 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:** we use professional advice for a wide range of purposes, including supplementing our internal capabilities in our legal, tax, internal audit, regulatory, and ICT teams with specialist skills and advice as required.

As a regional employer, we may struggle to attract specialist professionals, particularly from overseas, who are less familiar with our locations. This means we need to remain competitive with our benefits packages.

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

ICT Opex

ICT Opex covers ICT costs associated with operating our 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 that we comply 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

The software industry as a whole is moving to subscription 'pay-as-you-go' models due to cloud-delivered software and technologies. It is likely in the 2018-2022 timeframe we will use more cloud based software as service subscriptions meaning expenditure previously classified as Capex will increasingly be occurred as Opex.

Our forecasts are based on the most accurate information we have been able to obtain from suppliers and service providers and is based on the current technologies available and required scale to meet our needs.

H.3.2. Business support expenditure over the planning period

Our Business Support Opex forecast includes expenditure related to the functions that support our 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 Firstgas' Business Support Opex is allocated to our gas transmission business in accordance with our cost allocation policy.

H.3.3. Business support allocation methodology

The allocation of Business Support costs to our transmission and distribution businesses is based on a combination of three factors. The first, which is applied to expenditure that has a relationship with the assets (such as ICT systems) is an allocation on a proportion of RAB basis. The second, which is related more to supporting the people in our business (such as-building costs) 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.

H.4. PERFORMANCE MEASURES

This section describes our performance targets 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 targets have been developed to align with the definitions developed by the Commerce Commission for Information Disclosure.

H.4.1. Safety

We routinely monitor health and safety performance (internally and externally) and the performance of our core contractors. In addition, we have a strong reporting culture and all incidents are reviewed weekly to ensure the appropriate level of investigation and incident owner are assigned.

Table 9: Safety – historical performance

	FY2015	FY2016	FY2017	FY2018	FY2019
Lost Time Injuries	0	0	0	0	0

Safety Target

Zero lost time injuries.

Our historical performance has met this target however we will increase our focus on critical risks, particularly those that can result in serious injury or fatality. Safety initiatives include the following:

- **Collaboration:** we work collaboratively with our partner service providers. For example, we are making a step change in works planning to produce our plans earlier and improve their stability. This will create an environment where our staff and service providers can operate more safely. We are also working with service providers to get better policies, work practices and reporting disciplines.
- **Asset management framework:** is being used to drive safe outcomes. We are implementing Safety by Design principles and applying these across the full asset lifecycle. We are training workers in these principles.
- **Communications:** we are supporting health and safety committees to work on meaningful projects, allocating resources to regularly communicate to workers, and setting up reward programmes to recognise individuals' behaviour.
- **Safety systems:** we are providing service specifications and policies to service providers to ensure best practice, reviewing work management policies and providing an improved and transparent public safety management system.

H.4.2. Security and reliability: Response Time to Emergencies (RTE)

Firstgas take the safety of the public and its work force very seriously. Our aim is 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 10: RTE – historical performance

	FY2015	FY2016	FY2017	FY2018	FY2019
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.4.3. 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 of our control. We take all reasonable and prudent steps to prevent such events. If an unplanned interruption should occur we will endeavour to restore supply as soon as practicable consistent with our overriding health and safety obligations towards our staff, the public and the environment.

Table 11: Unplanned Interruptions – historical performance

	FY2015	FY2016	FY2017	FY2018	FY2019
Number of Unplanned Interruptions	0	0	0	2	1
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.4.4. Security and reliability: Compressor availability

Compressors are critical to the performance of our transmission system. Without them, the system is not able to consistently deliver consumers' contractual capacity. 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 12: Compressor availability – historical performance

	FY2015	FY2016	FY2017	FY2018	FY2019
Compressor fleet reliability	95%	94%	95%	96%	97%
Compressor fleet availability	85%	81%	86%	83%	89%

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

Compressor Availability Target

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

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

H.4.5. 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 distribution systems. Escapes are defined as any escapes of gas confirmed by Firstgas excluding third party damage events, routine survey findings and no traces events.

Table 13: PRE – historical performance

	FY2015	FY2016	FY2017	FY2018	FY2019
PRE per 1000km	4.1	2.2	4	2	5

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

PRE Target

No more than 5 confirmed public reported escapes per 1000 km per year.

H.4.6. Environmental

We have a policy aim of providing a safe and reliable gas supply to our customers in a manner that minimises our impact on the environment. We are committed to comply with all legislative requirements and where possible exceed them.

Table 14: Environmental – historical performance

	FY2015	FY2016	FY2017	FY2018	FY2019
Impact on the environment	N/A	N/A	N/A	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.4.7. Compliance

A five-yearly certificate of fitness is issued to Firstgas by our approved inspection body Lloyds. Lloyds also carry out an annual audit comparing our practice to AS/NZS 2885. Our target is to have no non-compliances from the audit but in the case where a non-compliance is noted (which may occur occasionally) then we target to resolve the issue within three months.

Table 15: Compliance – historical performance

	FY2015	FY2016	FY2017	FY2018	FY2019
Number of non-compliances	N/A	0	1	0	2

We completed an annual certificate of compliance audit in 2019 and two non-compliances were noted. Both non-compliance items have been resolved.

Llyods Annual Audit Target

Number of non-compliances found during audit: 0

If a non-compliance is noted, then timeframe for rectification plan implementation: three-months

H.5. ASSET MANAGEMENT MATURITY ASSESSMENT TOOL

As a regulated of supplier of gas transmission services, we undertake a self-assessment of the maturity of our practices in relation to asset management using a prescribed Asset Management Maturity Assessment Tool (AMMAT).

The AMMAT seeks to identify the maturity of a company's current asset management practices, relative to an objective standard based on good asset management practices, such as that described in ISO 55000. The AMMAT consists of 31 questions from the ISO 55000 assessment module, scoring maturity in each asset management area on a scale from zero to four. The detailed results of our self-assessment are included as **Appendix B** to the AMP.

We support the disclosure of the AMMAT because it allows interested persons to understand how well we are managing our assets against an objective and internationally recognised standard.

H.5.1. AMMAT Results

The AMMAT has been used to assess the maturity of our asset management practices. Our current score is 2.9 which reflects the improvements we have made over the last four years compared to our previous assessments of 2.6 and 2.7 in 2016 and 2018 respectively as illustrated in Figure 35.

Table 16: AMMAT Results

	2016	2018	2020	2021 TARGET
AMMAT score	N/A	0	1	3.0

Further detail on the improvements by category is illustrated in Figure 47.

Figure 35: AMMAT score by category

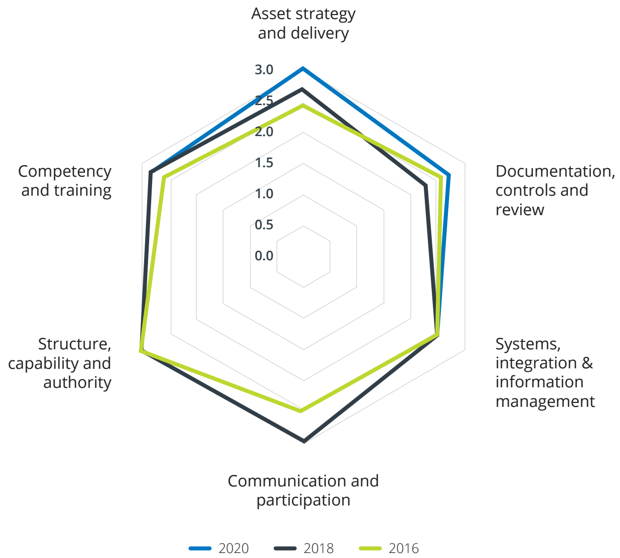
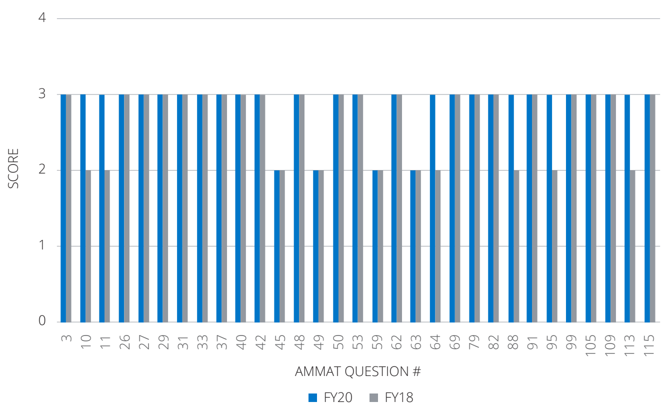


Figure 36 shows the overall performance for the 31 questions for this assessment compared to the assessment conducted in 2018. Overall we have 27 questions within maturity level 3 and the remaining 4 elements were within the maturity level 2.

The AMMAT result indicates that we have successfully embedded a number of key components of the Asset Management System that was implemented in 2018 but still some have activities where we need to improve to get maturity level 3 across all the areas.

Our goal, as documented in our 2018 AMP is to move to an average score of 3.0 by 2021. Reaching an average score of 3.0 will provide an indication that we are aligned with the requirements of *ISO 55000.*

Figure 36: AMMAT detailed results for FY2018 and FY2020



The variances and evidence summary for the improvements made over the last two years are detailed in Table 17.

Table 17: Variance detail between 2018 and 2020

QUESTION NO.	FUNCTION	QUESTION	SCORE 2018	SCORE 2020	EVIDENCE – SUMMARY
10	Asset management strategy	What has the organization done to ensure that its asset management strategy is consistent with other appropriate organizational policies and strategies, and the needs of stakeholders?	2	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 organisation's asset management strategy is consistent with its other organisational policies and strategies.
11	Asset management strategy	In what way does the organization's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organization has stewardship?	2	3	Asset Management Strategy has been developed and incorporated into the AMP and covers nearly all asset, asset types and asset systems.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	3	Firstgas has an asset management information system which aligns with its asset management requirements. A recent external review of the system by AECOM confirmed that it is relevant to our needs.
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?	2	3	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.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	3	Firstgas has asset performance monitoring linked to asset management objectives in place. There are several leading indicators and analysis of this data.
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?	2	3	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.

H.6. AECOM REVIEW

AECOM was commissioned by the Commerce Commission in April 2019 to objectively assess the risk management practices within New Zealand's gas pipeline businesses.[23] They reviewed existing information relevant to risk management processes, procedures and information, and supplemented these findings with a series of on-site meetings and discussions with relevant staff.

The general risk management assessment was supplemented by a separate geotechnical risk management review for the Firstgas transmission network.

Management reviewed and provided feedback on the draft reports in August 2019, and the final reports[24] were published via a Commerce Commission media release on 15 October 2019.

H.6.1. Results For Firstgas

It was pleasing to see the hard work that Firstgas has put into managing both our gas transmission and distribution businesses over the last three years is reflected in the reviews. In particular, the risk management review highlights the strong continuous improvement culture that we have established across our businesses. It is also great to see that the geotechnical risk review highlights that we have good, well documented processes in place to identify geohazards, and to evaluate and manage the risks associated with the identified hazards.

Management believe that the reports are well structured and provide the reader with a good understanding of how Firstgas manage risk and specifically geotechnical risk.

H.6.2. Main findings from the AECOM reports

The main findings from the reports have been extracted and included below.

Transmission Risk Management Review

Firstgas Transmission is approaching the level of risk management we [AECOM] believe to be best appropriate for such an organisation. We consider the current rating is commendable considering:

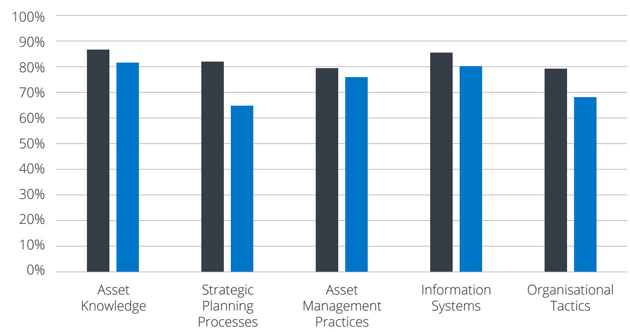
- The organisation is very new, and has needed to implement changes to systems and approaches established by the previous networks owner to reflect the size of Firstgas and the relevant networks; and
- There is clear evidence of ongoing improvement activities.

We were impressed by the demonstrated use of systems and risk principles to drive actions. We were also impressed with the clear evidence throughout the Firstgas offices that risk was a high priority with scheduled risk management workshops seen, incidental conversations regarding risk management overheard and risk management framework posters displayed in prominent places. We also observed that there was a strong culture of continuous improvement.

Many of the identified gaps will be addressed through current improvement activities. The key gaps reflect:

- A slightly narrow focus to the network risk management;
- Limited understanding of what security of supply risk external stakeholders consider acceptable;
- Although strategic mains and high consequence areas are identified, aspects considered when identifying critical assets are somewhat narrow;
- Limited systematic optimisation of activities associated with risks and/or drawing on risk principles;
- Although there is a good understanding of infrastructure failure profiles and renewal needs in the first ten years, there is limited understanding of these aspects in the longer-term; and
- Some systems are not integrated to exploit their ease of use and functionality.

Figure 37: Gap analysis for Firstgas Transmission



	Asset Knowledge	Strategic Planning Processes	Asset Management Practices	Information Systems	Organisational Tactics
Best Appropriate	86%	82%	79%	85%	79%
Current	81%	64%	76%	78%	68%

23. Four gas distribution businesses (Firstgas distribution, Powerco, Vector and Gasnet) and Firstgas' transmission business.
24. Copies of the reports are available on the Commission's website: https://comcom.govt.nz/__data/assets/pdf_file/0021/180462/Review-of-First-Gas-transmission-pipelines-geotechnical-risk-management-AECOM-report-17-September-2019.PDF and https://comcom.govt.nz/__data/assets/pdf_file/0020/180461/Review-of-gas-pipeline-businesses-asset-management-plans-AECOM-report-4-October-2019.PDF

Inter-organisation comparison

Asset and risk management practices across the five organisations assessed were reasonably consistent. This reflects the regulatory requirements placed on them, and the adoption of technical standards which are prescriptive in nature.

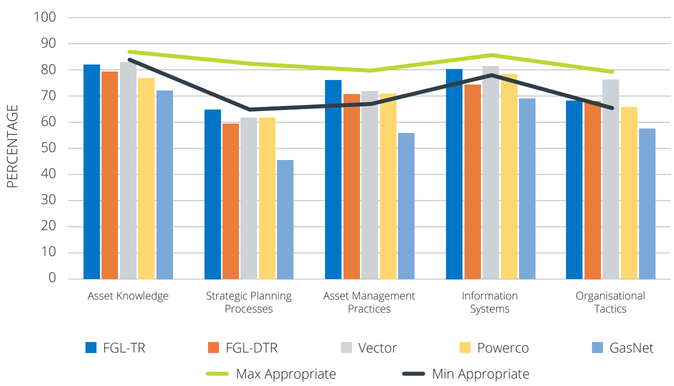
The graph below indicates the relative positions of each of the organisations across the five categories assessed, noting that the green line represents the highest level of "best appropriate practice" and the blue line represents the lowest level of "best appropriate practice". In broad terms, the level of risk management practice adopted reflects the size and criticality of the organisations themselves, and their networks and services provided. Asset knowledge and the systems to manage this information were the highest scoring categories, with strategic planning processes scoring the lowest.

All organisations had gaps identified to reach a level of risk management we believe is best appropriate for them. All the organisations have identified a programme of ongoing improvements to their risk management practices which, when completed, will get many of those aspects that currently lag to a best appropriate level.

Further, we believe this reflects a continuous improvement approach, one of the fundamental cornerstones of sound infrastructure management. This means that absolutes at any given time can be difficult to categorically define without the risk of stifling innovation and improvement.

Firstgas Transmission is the highest scoring, or close to the highest scoring organisation within each of the categories, and GasNet the lowest. Vector's strong organisational structure and processes are reflected in the Organisational Tactics category.

Figure 38: Summary comparison of risk management practice



Transmission geotechnical risk management review

Firstgas recognises that the risk natural land movement poses to its gas pipelines can be managed or mitigated but cannot be entirely eliminated. Management processes and systems are in place to identify and assess geohazards and determine whether and how to monitor or remediate, and to prioritise remediation works. The procedures are regularly reviewed in accordance with *AS/NZS 2885* and Firstgas is currently undertaking a programme of work to capture historical information within a GIS system that will provide a much improved and more accessible record of identified geohazards and their management.

Firstgas support their dedicated (and personally committed) pipeline integrity (geohazards) specialist with other field technicians and experienced engineering consultants, some of whom have a long history of geohazard assessment and management on the pipelines.

In accordance with the Brief, the following comments confirm that, in the opinion of the reviewer, Firstgas, in assessing their exposure to geotechnical risks, has:

- Made appropriate enquiries to understand and manage the risks;
- Sought adequate expert advice where required;
- Received advice that has adequately responded to the questions asked; and
- Appropriate processes in place for monitoring identified risks.

In the opinion of the reviewer, two areas for improvement in the management of geohazards that would help Firstgas to better monitor and manage the geotechnical risks are:

- Understanding of low probability, high impact events; and
- Capture of historical events.

Acting on recommendations from Risk review

Firstgas welcomed the review conducted by AECOM, it provided us with an opportunity to focus our continuous improvement initiatives into areas where we and the commerce commission can see value in our improvements.

APPENDIX I: SYSTEM CAPACITY

This appendix sets out our forecast demands on the system and describes our capacity determination methodology.

I.1. CAPACITY FORECASTS

Table 18: North Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/day)		
		FY2020	FY2025	FY2030
Tuakau 2	3,015	27,915	27,713	27,419
Harrisville 2	1,593	23,312	22,518	21,740
Ramarama	82	16,335	16,316	16,306
Drury 1	1,212	84,237	82,641	80,688
Pukekohe	349	17,663	17,053	16,448
Glenbrook	6,500	15,833	15,524	15,231
Greater Auckland	53,461	65,068	60,296	58,274
Hunua (Three DPs)	1,235	74,058	70,957	69,144
Flat Bush	1,713	71,803	68,007	65,974
Waitoki	678	3,559	3,238	3,176
Marsden (Both DPs)	15,641	1,687	1,494	1,421
Whangarei	555	1,779	1,581	1,508
Kauri + Maungaturoto	2,500	251	78	14
Alfriston	20	9,199	9,198	9,198
Warkworth	221	14,364	13,969	13,569
Warkworth 2	1,577	486	482	479

The peak week was the week ending the 28 June 2019.

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.

Table 19: North Pipeline Delivery Point Capacity Forecast

NORTH PIPELINE DELIVERY POINT	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
Alfriston	112	148	148	148	336		Regulators	
Bruce McClaren	2,374	2,378	2,378	2,378	2,500		Bath Heater	
Drury 1	2,466	2,450	2,450	2,450	2,700	2024	Bath Heater	
Flat Bush	2,673	2,511	2,511	2,511	6,590		Meter	
Glenbrook	12,210	12,372	12,372	12,372	13,213		Meter	
Harrisville 2	3,788	3,666	3,666	3,666	6,683		Meter	
Henderson	9,448	10,662	10,662	10,662	13,500		Meter	
Hunua 1	648	711	711	711	1,092		Regulators	Filter and heater are shared by these 2 DPs
Hunua (Nova)	576	621	621	621	740		Meter	
Hunua # 3	912	1,275	1,275	1,275	3,680		Meter	Gas is delivered at pipeline pressure
Kauri DF	3,094	3,249	3,249	3,249	2,566	≤ 2020	Regulators	
Kingseat	12	34	34	34	50		No heater. Flow is limited by cooling across regulators	
Marsden 2	178	216	216	216	788		Regulators	Filter, heater and 1st-cut regulators are shared by the 2 DPs
Marsden 1 (Refinery)	17,696	19,178	19,178	19,178	19,360		Meter	
Maungaturoto	2,444	2,777	2,777	2,777	3,300		Bath Heater	

NORTH PIPELINE DELIVERY POINT	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
Papakura	16,484	20,908	20,908	20,908	30,600		Meter	
Pukekohe	671	741	986	1,231	705	≤ 2020	Regulators	
Ramarama	376	392	490	588	320	≤ 2020	Meter	
Tuakau 2	5,295	5,254	7,780	10,305	8,700	2026	Heater, meter	Second heater will be installed prior to 2026
Waikumete	10,003	10,510	10,510	10,510	18,720		Meter	
Waitoki	1,768	1,932	2,384	2,835	2,900		Bath Heater	Capacity shown is for the heater which will be installed in 2020.
Waiuku	49	560	560	560	1,331		Regulators	New station
Warkworth No 2	2,426	2,426	3,426	3,426	2,900	2023	Bath Heater	Dominated by glass house load (Southern Paprika).
Wellsford	0	0	0	0	50		No heater. Flow is limited by cooling across regulators	
Westfield	40,698	42,121	43,803	45,485	72,850		Meter	
Whangarei	1,019	1,073	1,073	1,073	1,393		Regulators	

Table 20: BOP Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/day)		
		FY2020	FY2025	FY2030
Broadlands	235	3,983	3,907	3,884
Edgecumbe	4,611	3,211	3,075	3,032
Gisbourne	1,167	4,003	4,002	4,000
Mount Maunganui	2,586	3,394	1,676	1,216
Tauranga	1,066	2,789	1,699	1,668
Kawerau (Three DPs)	2,511	11,966	11,382	11,181
Kihikihi	296	27,619	23,734	22,355
Kinleith (Both DPs)	13,656	31,962	27,698	25,001
Lichfield (Both DPs)	5,763	21,762	21,591	19,925
Opotiki	64	3,721	3,695	3,669
Putaruru	375	32,281	19,241	16,093
Rangiuru	195	831	831	781
Reporoa	2,009	5,583	5,462	5,415
Rotorua	1,758	2,357	2,313	2,303
Taupo	586	4,820	4,721	4,687
Te Puke	182	3,021	1,342	1,009

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2020	FY2025	FY2030
Tirau (Both DPs)	1,425	15,331	14,429	10,157
Tokoroa	468	25,368	21,857	19,303
Waikeria	87	28,247	23,782	22,377
Whakatane	3,656	2,523	2,417	2,383

The peak week for this system was the week ending 27 September 2019.

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 estimated demand at a new Delivery Point proposed near Tauriko (on the line to Tauranga/Mt Maunganui) has been included in 2025 and 2030, at 3,300 GJ/day.

Table 21: BOP Station Capacity Forecast

BOP PIPELINE	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
Broadlands	651	655	655	655	739		Regulators	
Edgecumbe	19	21	27	33	230		Meter	Heater and 1st-cut regulators are shared
Edgecumbe DF	5,942	6,099	6,099	6,099	6,100		Bath Heater	
Gisborne	2,844	3,938	3,938	3,938	5,500		Bath Heater	
Kawerau (Tissue)	838	843	843	843	2,423		Regulators	Filter and heater shared by the 3 Kawerau DPs have maximum capacity of 10,870 SCM/hour
Kawerau (Pulp & Paper)	2,132	2,195	2,195	2,195	4,846		Regulators	
Kawerau	162	185	185	185	325		Regulators	
Kihikihi	880	820	946	1,072	2,090		Meter	
Kinleith (Pulp & Paper)	27,155	30,611	30,611	30,611	30,355		Regulators	Filter, heater and 1st-cut regulators shared by the 2 Kinleith DPs have maximum capacity of 38,800 SCM/hour
Kinleith	243	306	306	306	367		Regulators	
Lichfield DF	2,805	2,819	2,819	2,819	4,970		Meter	
Lichfield 2	4,486	5,246	5,246	5,246	6,242		Regulators	
Mt Maunganui	3,229	3,404	3,638	3,872	4,680		Meter	
Okoroire Springs	0	0	0	0	50		JT cooling limits station capacity, no WBH	
Opotiki	168	186	186	186	270		Filter	
Papamoa	592	605	861	1,117	4,050		Meter	Shared filter, heater and 1st-cut regulators have maximum capacity of 2,730 SCM/hour
Papamoa 2	661	676	962	1,248	4,050		Meter	

BOP PIPELINE	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
Putaruru	481	507	507	507	780		Bath Heater	
Pyes Pa	804	852	988	1,125	1,790		Meter	
Rangiuru	525	653	653	653	978		Regulators	
Reporoa	2,521	2,603	2,603	2,603	3,570		Pipework	
Rotorua	3,364	3,690	3,690	3,690	5,800		Bath Heater	
Taupo	1,173	1,271	1,271	1,271	4,340		Meter	
Tauranga	1,894	2,015	2,253	2,491	2,580	2025	Meter	
Te Puke	435	446	455	465	900		Meter	Heater and 1st-cut regulators are shared with Rangiuru. Maximum capacity (set by the regulators) is 2,540 SCM/hour
Te Teko	0	0	0	0	147		Regulators	
Tirau	45	67	67	67	600		Meter	Heater is shared by the 2 DPs
Tirau DF	2,314	2,439	2,439	2,439	4,200		Bath Heater	
Tokoroa	1,315	1,367	1,367	1,367	2,590		Meter	
Waikeria	184	215	675	675	845		Regulators	Forecast increase due to Corrections Dept. prison expansion
Whakatane	4,128	4,423	5,011	5,600	4,400	≤ 2020	Meter	Meter limitation at the Whakatane board mill.

Table 22: Central North Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/day)		
		FY2020	FY2025	FY2030
Cambridge	1,897	1,461	1,451	1,441
Greater Hamilton	7,737	16,973	15,789	14,528
Horotiu	1,215	11,471	10,883	10,259
Kiwitahi	1,061	3,605	3,126	2,788
Morrinsville	1,194	2,784	2,635	2,477
Tatuanui	1,500	3,584	3,366	3,144
Te Rapa Cogen	23,200	11,999	11,010	9,967
Waitoa	1,441	2,845	2,748	2,547

The peak week was the week ending 23 August 2019.

Compression at Rotowaro was modelled running continuously with a constant discharge pressure of 84 barg.

Table 23: Central North Pipeline Delivery Point Capacity Forecast

CEN PIPELINE DELIVERY POINT	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
Te Rapa Cogen	19,124	27,300	27,300	27,300	27,304		Bath Heater	
Hamilton Temple View 1	9,354	10,437	10,437	10,437	10,800		Meter	
Cambridge	2,997	3,093	3,093	3,093	4,310		Meter	
Hamilton Te Kowhai	5,583	6,029	6,029	6,029	9,376		Regulators	
Waitoa	1,959	2,113	2,113	2,113	3,200		Filter	
Kiwitahi 1 (Peroxide)	1,183	1,188	1,188	1,188	3,240		Filter	Filter, heater and regulators also used by Kiwitahi 2 DP
Kiwitahi 2	185	185	185	185	340		Meter	
Tatuanui DF	1,950	2,077	2,077	2,077	3,240		Filter	
Morrinsville SS – shared equipment	2,239	2,800	2,800	2,800	3,800		Bath Heater	
Morrinsville DF	1,827	2,233	2,233	2,233	4,110		Meter	
Horotiu	1,991	1,991	1,991	1,991	4,310		Meter	
Morrinsville	413	502	502	502	1440		Meter	
Matangi	17	17	17	17	50		No heater. Flow is limited by cooling across regulators	

Table 24: Central South Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/day)		
		FY2020	FY2025	FY2030
Eltham	632	9,584	9,455	9,445
Inglewood	138	7,513	7,345	7,344
Kaponga	7	7,644	7,476	7,475
New Plymouth	3,516	3,141	2,982	2,967
Stratford	262	44,554	37,848	37,625
Waitara	334	5,716	5,411	5,410

The peak week, with Pokuru 2 offtake excluded, was the week ending 28 June 2019.

Pokuru offtake was set to zero during modelling.

Compression at Mahoenui was not running during modelling.

Kapuni compression was modelled running continuously with a constant discharge pressure of 84 barg.

Table 25: Central South System Station Capacity Forecast

CES PIPELINE DELIVERY POINT	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
New Plymouth	6,037	6,344	6,404	6,465	7,800		Bath Heater	
Eltham	913	929	994	1,058	1,394		Regulators	
Waitara	837	883	1,078	1,274	1,130	2026	Regulators	
Stratford	690	738	950	1,162	1,130	2029	Regulators	
Inglewood	379	432	432	432	384	≤ 2020	Regulators	
Kaponga	16	25	25	25	140		Regulators	

Table 26: South Pipeline System Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/day)		
		FY2020	FY2025	FY2030
Ashurst	28	12,165	12,054	11,954
Belmont	6,688	11,308	11,215	11,124
Dannevirke	169	11,694	11,560	11,418
Feilding	946	4,556	4,531	4,516
Foxton	160	15,157	15,032	14,849
Hastings (Both DPs)	7,437	10,298	10,300	10,278
Hawera (Both DPs)	1,477	46,403	43,393	42,942
Kaitoke	98	4,136	4,129	4,131
Kakariki	269	10,708	10,680	10,654
Lake Alice	200	4,768	4,762	4,756
Levin	1,053	6,290	6,267	6,245
Longburn	863	5,446	5,417	5,389
Manaia	106	3,543	4,796	3,541
Mangaroa	90	9,243	9,127	8,997
Marton	916	8,522	8,508	8,501
Otaki	71	12,090	11,985	11,884
Pahiatua (Both DPs)	2,546	5,507	5,466	5,425
Palmerston North	3,847	4,079	4,050	4,035
Greater Kapiti	917	11,501	11,439	11,669
Patea	109	36,107	33,886	33,412
Takapau	406	9,400	9,614	9,178
Tawa (Both DPs)	11,011	5,037	5,037	5,037

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/day)		
		FY2020	FY2025	FY2030
Greater Waitangirua	1,500	11,813	11,725	11,646
Waitotara	126	39,387	37,614	37,421
Wanganui	4,433	37,971	35,291	34,968
Waverley	2	984	983	981

The South System's Peak week was the week ending 23 August 2019.

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. This has been reassessed since the 2019 AMP.

Kapuni compression was modelled running continuously with a constant discharge pressure of 84 barg.

Kaitoke compression was modelled running continuously with a constant discharge pressure of 84 barg.

Table 27: South System Station Capacity Forecast

SOUTH PIPELINE DELIVERY POINT	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
Ashhurst	91	100	100	100	137		Bath Heater	Electric Heater
Belmont	14,212	14,025	14,359	14,694	14,991		Bath Heater	Heater to be replaced in 2020
Dannevirke	496	492	593	694	480	≤ 2020	Regulators	
Feilding	1,827	1,824	1,908	1,993	3,400		Filter	
Flockhouse	0	0	0	0	50		No heater. Flow is limited by cooling across regulators	
Foxton	308	325	325	325	554		Regulators	
Foxton	308	325	325	325	554		Regulators	Filter, heater and 1st-cut regulators are shared, with maximum capacity 9600 SCM/hour. New heater to be installed in 2020
Hastings	12,010	12,102	13,204	14,306	9,600	≤ 2020	Bath Heater	
Hastings (Nova)	1,579	1,468	1,692	1,916	4,450	0		

SOUTH PIPELINE DELIVERY POINT	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
Hastings	12,010	12,102	13,204	14,306	9,600		Bath Heater	Filter, heater and 1st-cut regulators are shared, with maximum capacity 9600 SCM/hour. New heater to be installed in 2020
Hastings (Nova)	1,579	1,468	1,692	1,916	4,450	0	Meter	
Hawera	2,464	3,160	3,160	3,160	6,200		Bath Heater	Filter, heater and 1st-cut regulators are shared, with maximum capacity 6200 SCM/hour.
Hawera (Nova)	515	532	539	546	990		Meter	
Kairanga	28	23	31	40	50		No heater. Flow is limited by cooling across regulators	
Kaitoke	155	162	162	162	166		Bath Heater	
Kakariki	0	496	496	496	710		Meter	
Kuku	0	0	0	0	50		No heater. Flow is limited by cooling across regulators	
Lake Alice	280	289	318	346	318	2025	Regulators	
Levin	1,975	2,456	2,456	2,456	2,597		Meter	
Longburn	1,411	1,723	1,723	1,723	2,700		Regulators	
Mangaroa	149	150	152	154	178		Bath Heater	
Mangatainoka	36	36	Remove DP		678	0	Regulators	Tui brewery shut down. It's assumed the residual load will convert to LPG by 2025
Marton	1,207	1,267	1,267	1,267	2,800		Bath Heater	
Matapu	0	0	0	0	50		No heater. Flow is limited by cooling across regulators	
Manaia	156	163	163	163	219		Regulators	
Oroua Downs	213	217	217	217	330		Meter	
Otaki	223	266	266	266	652		Regulators	

SOUTH PIPELINE DELIVERY POINT	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
Pahiatua DF	4,144	4,144	4,144	4,144	4,605		Meter	Filter, heater and 1st-cut regulators are shared, with maximum capacity (set by pipework) of 7,130 SCM/hour.
Pahiatua	86	111	111	111	610		Meter	
Palmerston North	8,346	8,744	8,744	8,744	8,502		Regulators	
Paraparaumu	1,537	1,566	1,566	1,566	1,560		Pipework	
Patea	241	253	298	343	300	2025	Bath Heater	
Pauatahanui 1	1,005	1,034	1,110	1,186	2,593		Regulators	
Pauatahanui 2	0	0	0	0	50		No heater. Flow is limited by cooling across regulators	
Takapau	696	680	687	695	827		Regulators	
Tawa B	2,436	3,560	3,560	3,560	5,490		Pipework	
Te Horo	0	0	0	0	50		No heater. Flow is limited by cooling across regulators	
Waikanae 2	611	632	666	700	2,647		Regulators	
Waitangirua (Wellington) / Tawa A	21,063	23,348	23,348	23,348	26,984		Bath Heater	
Waitangirua (Porirua)	3,543	3,577	4,191	4,806	4,550	2027	Meter	
Waitotara	267	264	264	264	300		Bath Heater	
Whanganui	6,486	6,880	6,880	6,880	7,400		Bath Heater	
Waverley	5	15	15	15	50		No heater. Flow is limited by cooling across regulators	

Table 28: Frankley Road Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/day)		
		FY2020	FY2025	FY2030
Ammonia-Urea Plant		47,438	49,986	49,968
Kaimiro DP		81,650	186,475	186,475
Kapuni GTP		36,523	77,425	77,425
TCC + Stratford 2 + Stratford 3		32,570	87,570	87,570

The peak week was the week ending 30 August 2019.

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.

Table 29: Frankley Road Pipeline Delivery Point Capacity Forecast

FRANKLEY ROAD PIPELINE DELIVERY POINT	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
TCC	64,272	71,000	0	0	110,530		–	Expected to be shut down by 2025
Stratford 2	48,824	62,500	62,500	62,500	62,500		–	
Stratford 3	37,550	67,708	67,708	67,708	177,000		–	Increase flow in projected from 2020 due to expansion at the Ahuroa storage facility
Ammonia-Urea (Fuel gas)	10,397	10,569	10,569	10,569	12,680		Regulators	
Ammonia-Urea (Process gas)	12,800	12,800	12,800	12,800	12,680	≤ 2020	Regulators	
Kapuni (Lactose)	204	214	214	214	385		Regulators	

Table 30: Maui System Pipeline Capacity Forecast

DELIVERY POINT	PEAK DEMAND (GJ/DAY)	OPERATIONAL CAPACITY (GJ/DAY)		
		FY2020	FY2025	FY2030
Huntly Town	20	58,693	52,664	40,300
Pirongia (Three DPs)	2,524	58,869	62,017	55,554
Otorohanga	29	63,741	68,213	54,379
Ngaruawahia	11	0	0	0
Te Kuiti North	52	3,199	3,099	1,857
Te Kuiti South	535	6,802	5,887	3,876
Oakura	22	5,318	3,387	5,306
Okato	24,000	446,000	255,735	342,300
Rotowaro	104,288	177,241	188,048	187,616
Pokuru	25,487	112,486	40,253	115,929
Bertrand Road	93,625	418,506	452,001	372,674
Huntly Powerstation	59,287	100,924	58,488	145,705

The peak week for this system was the week ending 20 September 2019.

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.

The Pukearuhe bypass line is a temporary installation which imposes some restriction on the pipeline. It has been allowed for in the 2020 forecasting but has been assumed to be replaced with full size pipe by FY2025.

Pipeline capacity was not determined for Okato or Ngaruawahia on account of their low demand.

Junction Road power station (Mangorei Delivery Point) was not yet operational during the peak week, however, it is assumed to be at the capacity requirement of 24,000 GJ/day.

Table 31: Maui Pipeline Delivery Point Capacity Forecast

MAUI PIPELINE DELIVERY POINT	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
Huntly Town	332	563	563	563	840		Regulators	
Pirongia	23	30	30	30	50		No heater. Flow is limited by cooling across regulators	
Te Awamutu North	398	591	591	591	860		Meter	The 2 DPOs share a filter, heater and 1st-cut regulators, with maximum capacity of 17,100 SCM/hour
Te Awamutu DF	4,262	4,262	4,262	4,262	7,500		Meter	
Otorohanga	145	155	155	155	129	≤ 2020	Regulators	Regulator near full capacity at minimum pressure, however since there is no growth at this station, experience indicates that up sizing this regulator is not needed.
Ngaruawahia	58	71	71	71	129		Regulators	
Te Kuiti North	188	429	429	429	570		Meter	+200 SCMH predicted for new load in 2020
Te Kuiti South	954	1,115	1,115	1,115	1,909		Regulators	Regulators being upgraded in 2020
Oakura	132	143	171	200	210		Meter	
Bertrand Road	61,920	221,076	221,076	221,076	0			This is an offtake pipe to Methanex Waitara Valley. Capacity only restrained by pipe size, flat industrial load and no growth.
Ngatimaru Road	145,130	162,688	162,688	162,688	N/A			Pohokura Gas Tie In (receipt point)

MAUI PIPELINE DELIVERY POINT	ACTUAL (SCM/HOUR)	FORECAST (SCM/HOUR)			CAPACITY (SCM/HOUR)	YEAR OF CAPACITY LIMIT	LIMITING EQUIPMENT	COMMENTS
	2019	2020	2025	2030				
Huntly Power Station	132,832	233,358	233,358	233,358	261,300		Filter	This DP and the Huntly Town DP share facilities at the upstream Huntly Offtake Station. There the pressure in the Huntly lateral is regulated to 50 barg. Since Maui line pressure is normally < 50 barg the regulators are usually wide open. Their maximum capacity is 185,000 SCM/hour
Mangorei	0	0	25,600	25,600	25,600		Meter	
Opunake	89	104	104	104	241		Regulators	
Okato	45	49	49	49	133		Regulators	
Pungarehu No. 1	0	1	1	1	50		No heater. Flow is limited by cooling across regulators	
Pungarehu No. 2	14	14	14	14	50		No heater. Flow is limited by cooling across regulators	

I.2 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.

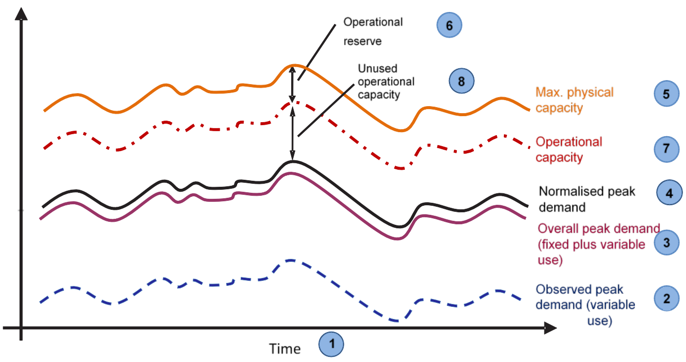
Pipeline data is taken from asset management systems and GIS.

I.3 PIPELINE CAPACITY FORECASTING METHODOLOGY

Our approach to determining the physical capacity of our 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 our modelling analysis we use Synergi software, which is a leading, internationally recognised product, produced by DNV GL.

Figure 39: 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 period

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.[25]

For most pipelines, the peak demand period is usually a sequence of high demand days (that may or may not include the peak demand day).

Peak demand on our 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[26]").

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[27]. To determine the pipeline's sustainable capacity, pressures must fully recover.

It is noted that in many international gas regimes, peak demand profiles[28] are considered over a 24-hour period only, and gas consumption is limited to ensure that pressures fully recover within this period. We have evaluated this method, 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, we have decided to maintain the five-day peak approach. Our 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 by observing actual variable demand patterns during the five-day peak (or, potentially, other peak demand period) for all delivery points on the pipeline.

25. Indicating that a further such peak demand period would be sustainable.
26. 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.
27. 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, First Gas generally operates it in a constant pressure mode (maintaining inlet pressure at relatively constant level).
28. 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.

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 of determining the available physical capacity of a pipeline, we do not need to forecast diversity.[29] 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.[30]

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, we model each power station's demand as its maximum contractual entitlement rather than its actual demand in the five-day peak.

Step 4 – Normalised peak demand

The fourth 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 our pipelines[31] 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 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 fifth 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.

29.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.
30. As discussed in the System Security Standard.
31. The Bay of Plenty pipeline does not display a strong overall winter 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.[32] 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.

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 our 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[33]. 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 our 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[34] redundancy (as set out in the system security standard). However, a redundant compressor may also fail, or fail to start,[35] 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 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.

32. 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.
33. 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.
34. 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.
35. 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.

I.4. 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.

There are 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.

APPENDIX J: EXPENDITURE OVERVIEW

This appendix sets out a summary of our expenditure forecasts for the current year and over the planning period. It is structured to align with our expenditure categories and with information provided in Appendices.

The forecasts presented here provide a consolidated view of our expenditure across our business. It provides high-level commentary and context on our planned investments during the planning period, including key assumptions used in developing our forecasts.

Each section includes cross references to an appendix with more information. To avoid duplication we have not restated discussions in previous appendices.

Note on expenditure charts and tables

The charts in this appendix depict budgeted expenditure for FY2020 and our forecasts for the planning period.

Expenditure is presented according to our 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 FY2020 thousand New Zealand dollars.

J.1 INPUTS AND ASSUMPTIONS

This section describes the inputs and assumptions used to forecast our Capex and Opex over the planning period.

J.1.1. Forecasting Inputs and Assumptions

Our forecasts rely on several inputs and assumptions. These include:

- Escalation to nominal dollars.
- Capital contributions.
- Finance during construction.

Escalation

Forecasts in this appendix are in constant value terms. In preparing Schedules 11a and 11b, we have escalated our real forecasts to produce nominal forecasts for Information Disclosure.

While we expect to face a range of input price pressures over the planning period, we have based our escalation approach on the consumer price index (CPI). This has been done to align forecast inflation with the initial 'exposure' financial model for the gas DPP. Therefore, for the purposes of this AMP, we have assumed changes are limited to CPI rather than adopting more specific indices or modelling trends in network components or commodity indices. Similarly, we have not sought to reflect trends in the labour market.

Table 32: CPI forecast

FOR YEAR ENDED	CPI
FY2020	0.00%
FY2021	2.01%
FY2022	2.00%
FY2023	2.01%
FY2024	2.00%
FY2025	2.00%
FY2026	2.00%
FY2027	2.00%
FY2028	2.00%
FY2029	2.00%
FY2030	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)

Our Capex forecasts exclude FDC. We have included a forecast of FDC based on expected commissioning dates in Schedule 11a in **Appendix B**.

J.2 EXPENDITURE SUMMARY

This section summarises our total Capex and Opex forecasts for the planning period.

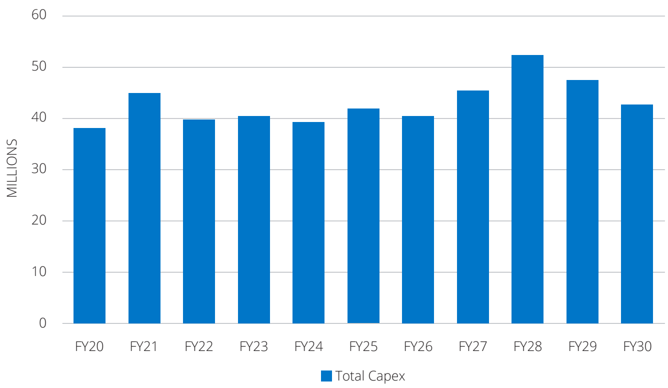
J.2.1. Total Capex

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**.

Our total forecast Capex for the planning period is shown in Figure 40 below.

Figure 40: Forecast total Capex (all figures in FY2020 prices)[36]



Our Capex profile reflects the underlying network needs discussed in this AMP. Key drivers for the expenditure trend include:

- **System growth:** system growth expenditure contributes to the increase in the latter part of the regulatory (DPP) period. The Warkworth lateral expansion was initially planned for FY2017- FY2019 as this was based on proposed growth in the Warkworth area. However, this demand has not materialised within the original timeframe and is anticipated to occur at the end of, or into the next DPP period. This has resulted in the deferral of the activities.
- **Renewals:** one of the main drivers for expenditure variance in FY2020 and FY2021 will be the execution of the Gilbert Stream realignment project. A short section of the 400 line needs to be re-aligned to mitigate risk associated from coastal erosion.
- **Non-network:** expenditure in FY2020 includes a portion of our total expenditure on heating systems associated with programmes or upgrades.

Our capital expenditure profile has altered from our 2018 AMP. The refinement of our asset management approaches has created a steady expenditure profile through the remaining regulatory period.

Table 33 below sets out the expenditure per year. These are consistent with our Schedule 11a disclosures included in **Appendix B**.

Table 33: Total forecast Capex on assets in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Capex	38,506	45,506	46,830	40,965	39,718	42,479	40,977	45,943	53,022	48,003	43,314

36. This is before adjusting for customer contribution and finance during construction (FDC).

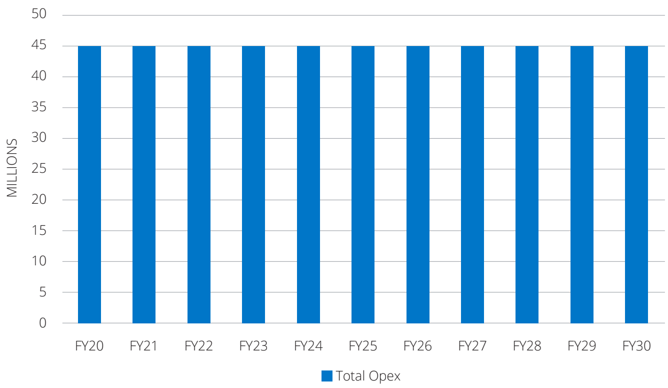
J.2.1. Total Opex

Our 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.

Our total forecast Opex for the planning period is shown in Figure 41 below.

Figure 41: Total Opex (all figures in FY2020 prices)



Our Opex for the period is generally forecast using FY2020 as a typical (or base) year. Remaining transitional expenditure has been removed and a trending approach applied to the remainder of the period. Individual forecasts have specific adjustments based on expected activity over the period.

There are a number of activities that will require increased levels of Opex to ensure we can meet our asset management objectives. However, we will look to find efficiencies in our operations in order to fund these activities without increasing overall spend.

Table 34 below sets out the expenditure per year. These are consistent with our Schedule 11b disclosures included in **Appendix B**.

Table 34: Total forecast Opex on assets in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Opex	44,684	44,684	44,684	44,684	44,684	44,684	44,684	44,684	44,684	44,684	44,684

J.3 SYSTEM GROWTH CAPEX

In this section we summarise our expected investments in system development. Detail on the relevant projects is provided in **Appendix F**.

System development expenditure over the period will be mainly driven by third party requirements. For the majority of the period, we have included a baseline amount based on average historical spend. The increase in the latter part of the DPP period is attributed to the Warkworth lateral expansion originally planned to occur in FY2017-FY2019.

Moreover, currently is under discussion the conversion of the existing Cardiff Receipt Point into a Bi-directional Point in FY2021 and the proposed Tauriko Delivery Point for Firstgas distribution's network and Otorohanga 2 Delivery Point in FY2022.

Table 35 below sets out the expenditure per year. These are consistent with our Schedule 11a disclosures included in **Appendix B**.

Figure 42: System Growth Capex (all figures in FY2020 prices)

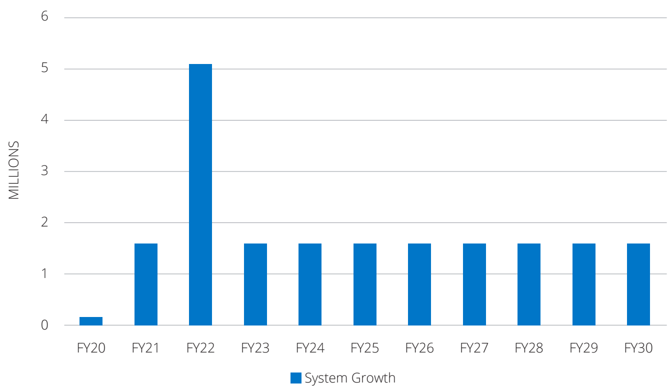


Table 35: System Development Capex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Capex	156	1,600	5,100	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600

J.4 CUSTOMER CONNECTIONS CAPEX

In this section we summarise our expected investments to enable customer connections.

Customer Connection expenditure over the period will be mainly driven by third party requirements. For the majority of the period we have included a baseline amount based on average historical spend. In addition, there are potential connections that would require significant one-off investments. These have not been included in our forecast as they have not been confirmed by the connecting parties.

Table 36 below sets out the expenditure per year. These are consistent with our Schedule 11a disclosures included in **Appendix B**.

Figure 43: Total Customer Connection Capex in FY2020 prices

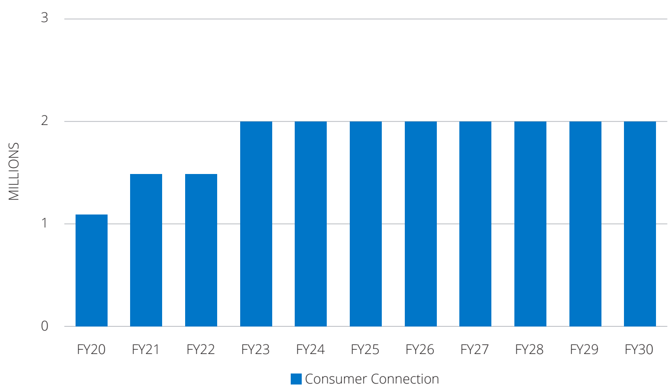


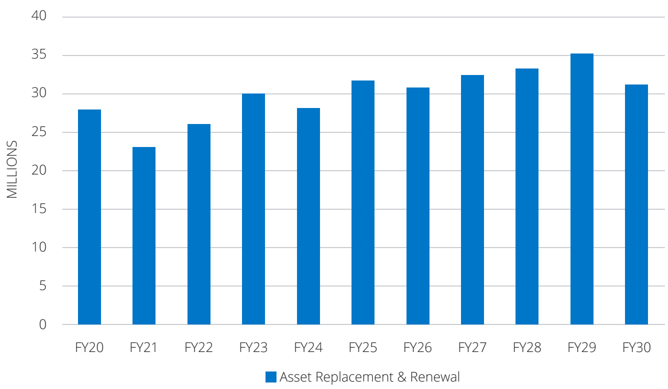
Table 36: Gross Customer Connection Capex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Capex	1,096	1,500	1,500	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000

J.5 ASSET REPLACEMENT AND RENEWAL CAPEX

In this section we summarise our expected investments to replace and renew our asset fleets. Detail on the included work and associated drivers is provided in Appendix H.

Figure 44: Replacement and Renewal Capex in FY2020 prices



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 L**, the key drivers of the expenditure profile over the period are a number of large projects. These include the following:

- The Delivery Point regulator replacement, heating systems replacement, PIG launchers and receivers refurbishment and intelligent pigging programmes represent the main drivers the asset replacement and renewal expenditure expected to occur in the planning period.
- Following a technical review of the Mangapukatea (White Cliffs) project, we have developed a model for the erosion, where specific triggers will cause the Mangapukatea realignment project to be initiated. The forecast expenditure for execution of this project has been excluded from our forecasts.

Table 37 below sets out the expenditure per year. These are consistent with our Schedule 11a disclosures included in **Appendix B**.

Table 37: Replacement and Renewal Capex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Capex	27,752	22,864	32,404	29,954	27,973	31,631	30,645	32,358	33,122	35,122	31,122

J.6 ASSET RELOCATIONS CAPEX

In this section we summarise our expected investments to relocate assets on behalf of third parties. Further detail on this expenditure is provided in Appendix H.

Consistent with average historical trends, we are forecasting a constant trend of asset relocations Capex over the period. Relocation projects are driven by third party needs and we typically align with the customers timelines. As a result, project delivery timing can shift significantly. The following relocations projects are included in the FY2021 workplan:

- Relocation of the 402 pipeline for Ports of Auckland Limited (POAL).
- Relocation of the 400 pipeline at Murphys Road.

Table 38 below sets out the expenditure per year. These are consistent with our Schedule 11a disclosures included in Appendix B.

Figure 45: Gross Asset Relocations Capex in FY2020 prices

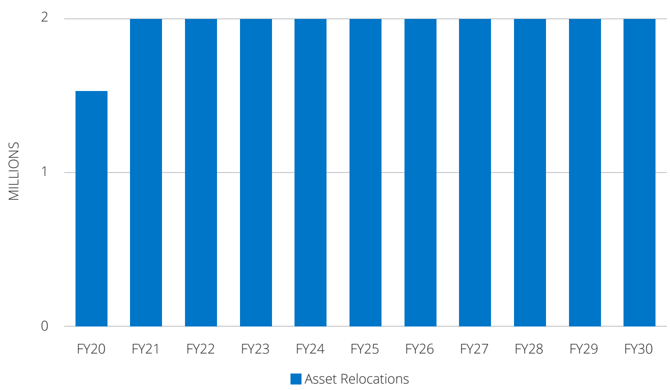


Table 38: Gross Asset Relocations Capex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Capex	1,586	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000

J.7 RELIABILITY, SAFETY AND ENVIRONMENT CAPEX

In this section we summarise our expected investments in reliability, safety and environment to support our asset management activities. Details on the included projects are provided in Appendix H.

Reliability, safety and environment is constant through the planning period.

Table 39 below sets out the expenditure per year. These are consistent with our Schedule 11a disclosures included in Appendix B.

Figure 46: Non-network Capex during the Planning Period

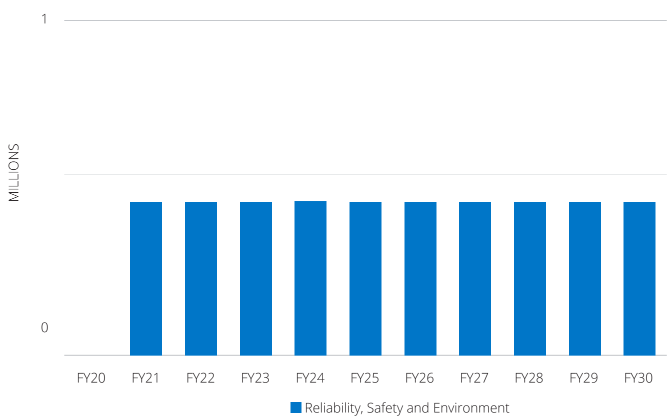


Table 39: Reliability, safety and environment Capex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Capex	0	500	500	500	500	500	500	500	500	500	500

J.8 NON-NETWORK CAPEX

In this section we summarise our expected investments in non-network assets to support our asset management activities. Detail on the included projects is provided in **Appendix H**.

Non-network Capex is allocated between our transmission and distribution businesses based on factors such as size of asset base (RAB) and staff headcount. Over the planning period we expect to invest in lifecycle-based asset renewals for IT equipment and office assets.

As part of our improvement programme, we have invested in new IT capabilities and office refurbishment in the early years of the period. In FY2021 we expect to undertake a lifecycle refresh of a number of IT systems. We also invested in updating our transmission-related OATIS system in FY2020; however, at the moment, the project is being reassessed. Further details can be found in **Appendix L**.

Table 40 below sets out the expenditure per year. These are consistent with our Schedule 11a disclosures included in **Appendix B**.

Figure 47: Non-network Capex in FY2020 prices

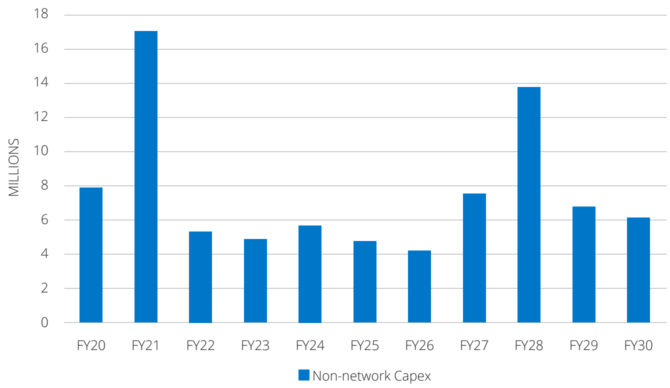


Table 40: Non-network Capex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Opex	7,916	17,043	5,326	4,911	5,645	4,748	4,232	7,484	13,800	6,781	6,091

J.9 NETWORK OPEX

In this section we summarise the Network Opex we expect to incur over the planning period. To align with Information Disclosure, we use the following expenditure categories.[37]

- 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. System Operations

Our SIE Opex forecast for the planning period is shown in Figure 48.

We expect both the cost of undertaking reactive maintenance (SIE) and overall work volumes on the transmission system to remain stable over the period.

Table 41 below sets out the expenditure per year. These are consistent with our Schedule 11b disclosure included in Appendix B.

Figure 48: SIE Opex in FY2020 prices

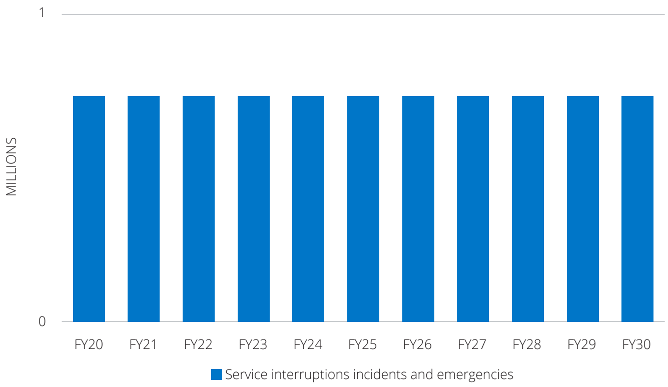


Table 41: SIE Opex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Opex	732	732	732	732	732	732	732	732	732	732	732

37. We currently do not assign expenditure to the ARR Opex category.

J.9.2. Routine and Corrective Maintenance and Inspection (RCMI)

Our RCMI Opex forecast for the planning period is shown in Figure 49.

We expect the cost of undertaking scheduled maintenance to be stable over the period. Whilst we may expect expenditure to increase, we believe we can offset the increase with delivery efficiencies (see below).

Some examples of steady cost pressures are set out below:

- In order to identify efficiencies and improve effectiveness in our maintenance area, we conducted a maintenance strategy review in FY2020.
- We have identified that geo-hazard risk will require extra expenditure so that we can complete the identification of risks across the transmission system and to fund ongoing monitoring of geo-hazard features.

Table 42 below sets out the expenditure per year. These are consistent with our Schedule 11b disclosure included in **Appendix B**.

Figure 49: RCMI Opex in FY2020 prices

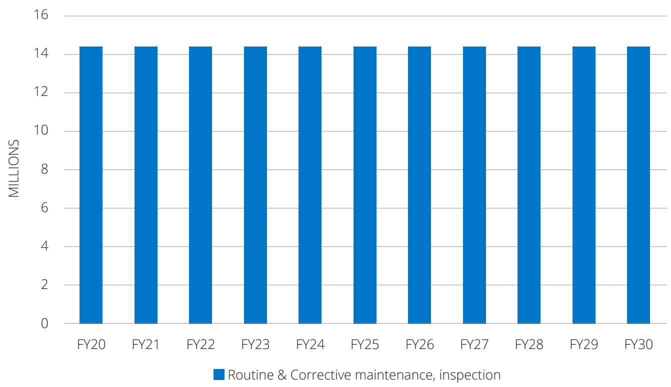


Table 42: RCMI Opex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Opex	14,293	14,293	14,293	14,293	14,293	14,293	14,293	14,293	14,293	14,293	14,293

J.9.3. Compressor Fuel

Our Compressor Fuel Opex forecast for the planning period is shown in Figure 50.

We expect the cost of compressor fuel to be largely stable over the next 10 years. However, the challenge we have had in the last two years is the prediction of the cost per unit. Moreover, there will probably be a cost reduction in the next 10 years due to the compression strategy.

Table 43 below sets out the expenditure per year. These are consistent with our Schedule 11b disclosures included in **Appendix B**.

Figure 50: Compressor Fuel Opex in FY2020 prices

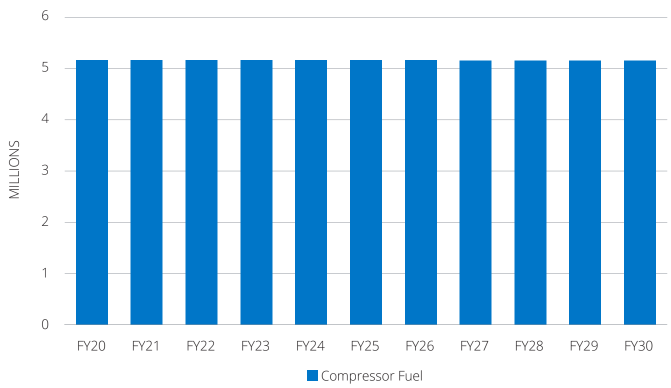


Table 43: Forecast compressor fuel Opex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Opex	5,208	5,208	5,208	5,208	5,208	5,208	5,208	5,208	5,208	5,208	5,208

J.9.4. Land Management and Associated Activity

Our forecast for costs associated with land management during the planning period is shown in Figure 51 below.

We expect these costs to be stable over the planning period.

Table 44 below sets out the expenditure per year. These are consistent with our Schedule 11b disclosures included in **Appendix B**.

Figure 51: Land Management Opex in FY2020 prices

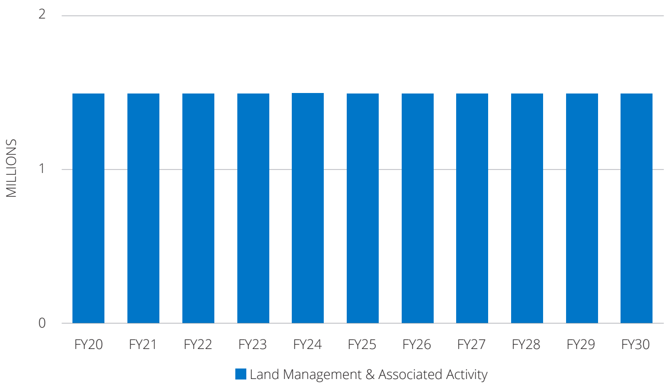


Table 44: Land Management Opex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Opex	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541

J.10 NON-NETWORK OPEX

In this section we summarise the non-network Opex we expect to incur over the planning period. To align with Information Disclosure, we use the following expenditure categories:

- 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 52.

Our overall costs for System Operations Opex will be consistent with average historical spend.

Table 45 below sets out the expenditure per year. These are consistent with our Schedule 11b disclosures included in **Appendix B**.

Figure 52: System Operations Opex in FY2020 prices

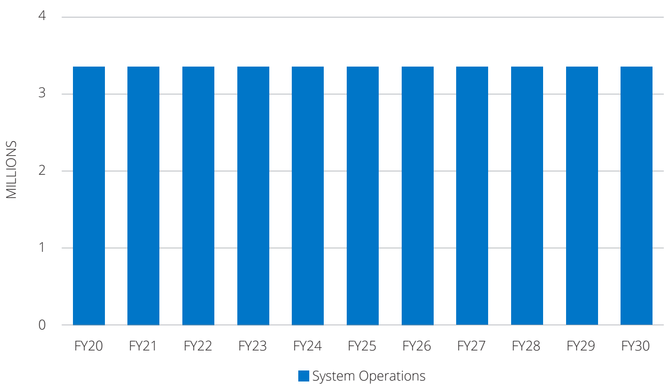


Table 45: System Operations Opex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Opex	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312	3,312

J.10.2. Network Support

Our Network Support forecast for the planning period is shown in Figure 53.

Our overall costs for Network Support Opex will be consistent with our average historical spend.

Table 46 below sets out the expenditure per year. These are consistent with our Schedule 11b disclosures included in Appendix B.

Figure 53: Network Support Opex in FY2020 prices

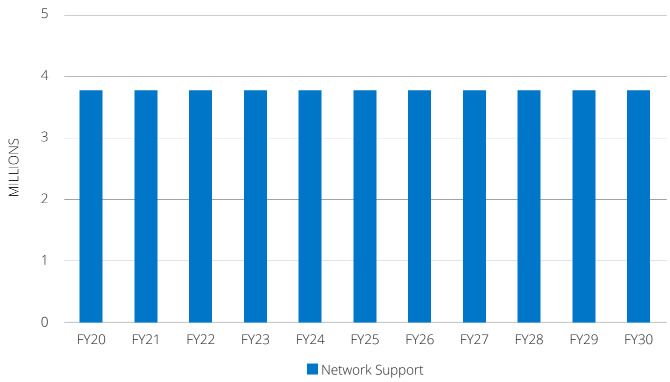


Table 46: Network Support Opex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Opex	3,807	3,807	3,807	3,807	3,807	3,807	3,807	3,807	3,807	3,807	3,807

J.10.3. Business Support

Our Business Support Opex forecast includes expenditure related to the functions that support our gas transmission business. It includes direct staff costs and external specialist advice. The other material elements are office accommodation costs, legal, and insurance costs.

A portion of Firstgas' total Business Support Opex is allocated to our gas transmission business in accordance with our cost allocation policy.

Our forecast for the planning period is shown in Figure 54.

Our overall costs for Business Support Opex will be consistent with average historical spend.

Table 47 below sets out the expenditure per year. These are consistent with our Schedule 11b disclosures included in Appendix B.

Figure 54: Business Support Opex in FY2020 prices

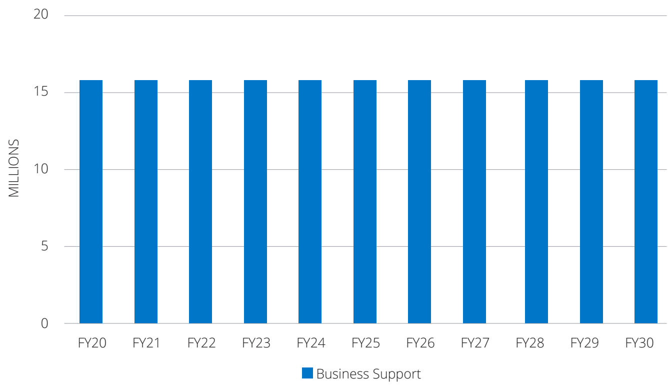


Table 47: Business Support Opex in FY2020 prices

YEAR	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
Opex	15,790	15,790	15,790	15,790	15,790	15,790	15,790	15,790	15,790	15,790	15,790

APPENDIX K: SCHEDULED MAINTENANCE

In general, our philosophy is to keep assets in use for as long as they can be operated safely, technically and economically. Our maintenance policies support this goal with a comprehensive set of processes, standards and schedules.

This appendix summarises our 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. It identifies any change in risks associated with the pipelines from a wide range of threats, that can be broadly categorised as:

- Third party interference
- Corrosion
- Natural events (flooding, earthquakes, slips etc.)

A Safety Management Study (SMS) of all assets was conducted in 2016 in accordance with *AS 2885*. There are a number of events or changes that 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

Currently, Firstgas is running a SMS programme on a rolling on a 5-yearly period. In the below table, the SMS schedule is outlined for the current 5-year period.

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 a number of 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.

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 our 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 due to the fact that the majority 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 48: Safety management study schedule

NAME/ REGION OR SYSTEM	QUARTER	YEAR	SEMESTER/ SEASON	NO OF LINES	STATUS
East to Bay of Plenty	Q2	2019	Winter	17	Completed
Taranaki	Q2	2020	Winter	19	
South to Wellington	Q2	2020	Winter	30	
North, Auckland & Waikato	Q2	2021	Winter	37	
Ahuroa	Q2	2023	TBD[38]	1	

38. TBD: To be defined.

Table 49: 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 we are implementing new technologies, where the benefits prove to be advantageous.

Cathodic Protection Inspections

Below we set out our scheduled inspections:

- Daily CP rectifier monitoring during the working week.
- 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 (except for 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 we set out a list of typical preventative inspections:

- 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 and routine inspections were implemented from FY2018 onwards.
- 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 in the compressor maintenance based on the results of recent investigations into component failures.

Routine vibration monitoring is completed on all engine and compressor packages. The 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.

We reviewed the OEM maintenance schedule and engaged with Turbine Efficiency (TE), an independent turbine specialist, to initiate a condition-based maintenance and overhaul programme. Under this regime, all components that are normally replaced under the OEM guidelines were inspected and where necessary, laboratory analysed and then where prudent, returned to service. We now have a more condition-based approach with TE.

Siemens also now offer a more condition-based approach, and Firstgas 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 50: 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 asset replacement and renewal capex and included in expenditure forecasts for this cost category.

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, and 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.

Our 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. We have adopted a condition-based approach and based upon expert condition assessment expect to operate the machines to their full 48,000 hours, thereby 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 in table 51.

Table 51: 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 activities are shown on the following page.

Table 52: 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, we operate a vibration analysis programme. Expertise is supplied by a third-party contractor and also they utilise Windrock analysis equipment that can provide a detailed condition assessment of both the engine and compressor unit, we have in house capability to operate this equipment.

We have in-house capability to perform all maintenance tasks 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 our resources are unavailable, or for larger tasks for which we do not have the required equipment.

Turnaround time for most work is around two to five days, depending on the availability of spares. Since we operate a large fleet of similar machines, 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 activities are shown below.

Table 53: 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

Maintenance is undertaken on hours run basis. Through the planned maintenance, it is anticipated that the units can remain operational indefinitely, upgrades will only be triggered by specific issues on either prime mover or compressor

Table 54: Electric drive compressors maintenance and inspection activities

FREQUENCY (EOH)	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 were used to implement a cooler replacement programme.

Table 55: Gas cooler maintenance and inspection activities

FREQUENCY (EOH)	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 56: MLV maintenance and inspection activities

FREQUENCY (EOH)	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 our 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.

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 our 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 that 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.

Water Bath Heaters (WBHs) are internally inspected every 10 years to assess their condition and to carry out any identified remedial work.

Heating systems comprise of a number of components and maintenance requirements and are summarised in table 56.

Table 57: Heating system maintenance and inspection activities

FREQUENCY (EOH)	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** 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** Inspection and Overhaul of Shell and Tube

Odorisation Plants

Odorant vessels are managed under our 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 58: Odorisation plant maintenance and inspection activities

FREQUENCY (EOH)	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 our 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 59: Coalescer maintenance and inspection activities

FREQUENCY (EOH)	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

Our gas metering systems (GMS) 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.

Data from metering systems is regularly monitored and analysed to identify and prioritise performance issues or trends.

Metering Systems comprise of several components and maintenance requirements are summarised below.

Table 60: Metering systems maintenance and inspection activities

FREQUENCY (EOH)	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

SCADA and Communications

The SCADA master station and communications systems located at Bell Block are regularly tested and 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 break-downs. We will work with communications 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 a number of components and maintenance requirements are summarised with activities listed in Table 61.

Table 61: SCADA and communications maintenance and inspection activities

FREQUENCY (EOH)	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 our Metering Requirements for Receipt and Delivery Point standard.

GCs comprise of a number of components and maintenance and inspection requirements are summarised below.

Table 62: GC maintenance and inspection activities

FREQUENCY (EOH)	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 63: PIG launcher and receiver maintenance and inspection activities

FREQUENCY (EOH)	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 a similar way as summarised below.

Table 64: Pressure regulator maintenance and inspection activities

FREQUENCY (EOH)	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.

PSV 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 65: PSV maintenance and inspection activities

FREQUENCY (EOH)	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 66: Isolation valve maintenance and inspection activities

FREQUENCY (EOH)	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 67: Filter maintenance and inspection activities

FREQUENCY (EOH)	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 68: Station ancillary 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

Table 69: Maintenance activities forecast expenditure in FY2020 prices

EXPENDITURE DESCRIPTION	FINANCIAL YEAR ($000)									
	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30
RCMI – Pipelines	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447
RCMI – Compressors	3,270	3,270	3,270	3,270	3,270	3,270	3,270	3,270	3,270	3,270
RCMI – Stations	8,157	8,157	8,157	8,157	8,157	8,157	8,157	8,157	8,157	8,157
RCMI – Special Crossings	39	39	39	39	39	39	39	39	39	39
RCMI – SCADA and communications	19	19	19	19	19	19	19	19	19	19
RCMI – Plant and equipment	361	361	361	361	361	361	361	361	361	361
RCMI – Total	**14,293**	**14,293**	**14,293**	**14,293**	**14,293**	**14,293**	**14,293**	**14,293**	**14,293**	**14,293**
Compressor Fuel	5,208	5,208	5,208	5,208	5,208	5,208	5,208	5,208	5,208	5,208
Land Management and Associated Activities	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541	1,541
Service Interruptions Incidents and Emergencies	732	732	732	732	732	732	732	732	732	732
Total	**21,775**	**21,775**	**21,775**	**21,775**	**21,775**	**21,775**	**21,775**	**21,775**	**21,775**	**21,775**

APPENDIX L: SIGNIFICANT PROJECTS

In this appendix, we provide a summary of the major projects we are undertaking in FY2021-FY2022.

Gilbert stream realignment project

Realigning the pipeline at Gilbert stream in Northern Taranaki remains a priority project for Firstgas. After delays to the work plan due to the level 4 COVID-19 restrictions, the construction of the pipeline is expected to complete in the autumn/winter of FY2021.

The 400Line is a pipeline of national significance and transports the main gas supply for Auckland. An 80-metre section of the 400Line at Pukearuhe, approximately 75 metres north of Gilbert Stream is threatened by marine erosion of the cliff face. The cliffs adjacent to the threatened area are nominally 50 metres high and the proximity of the 400Line is now approximately 9.4 metres to the top edge of the cliff at the nearest point. Assessment of the regular monitoring results since 2015 has resulted in a "high" assessment of the integrity risk to the pipeline. The Gilbert Stream realignment project remains a key project for Firstgas and is expected to move to execution phase in late 2022. We have already completed significant preparatory work for this project. Originally planned for earlier in this regulatory period, the deferral of works was driven by the business need to verify and optimise the design of the realignment of the pipeline section. We have now completed the FEED work, the emergency response plan and detailed design work.

Site construction work that started earlier this year ceased when New Zealand moved to Alert Level 4 in response to the COVID-19 pandemic. However, planning is now underway to return to site and the coming year will see us progressing to the execution phase with pipeline construction complete in the autumn/winter of 2021.

Emergency response planning

Firstgas continues monthly monitoring of erosion at the Gilbert Stream site. Whilst this has not increased at the time of writing, Firstgas remains prepared to respond if coastal erosion were to accelerate and put the integrity of the pipeline at risk. An emergency response plan (ERP) has been developed to manage the staged response to continued coastal erosion at Gilbert Stream. The ERP has also been approved for use and allows Firstgas to react quickly if erosion progresses ahead of the replacement project. The ERP ensures the type of response to each trigger event is understood and documented and includes:

- Equipment and resources preparedness
- The sequence of actions expected in line with specific trigger events.

GTAC IT platform development

Firstgas has been working to replace the two existing transmission access codes since August 2016. The new Gas Transmission Access Code (GTAC) is a transformational strategic initiative for the New Zealand gas industry. The consolidation of the two pipeline codes will provide a more effective way of making pipeline capacity available, thereby reducing barriers to market entry and improving the efficiency of the gas market.

In February 2019, Gas Industry Co, the industry regulator, released its Final Assessment Paper, which concluded that the GTAC is materially better than the existing codes. The next step is delivery of the platform on which the GTAC will operate. This system will provide efficiencies in managing the commercial operations of the pipeline system through automated nominations, approvals and scheduling systems. It is important that GTAC is supported by a stable and workable technology solution so that Firstgas can ensure that service expectations can be met.

Unforeseen complexities in developing the IT platform, including a large degree of customisation, as well as the impact of COVID-19, have meant that the original implementation timeframes have been extended. None of the issues associated with the project are insurmountable, and Firstgas is planning for the required processes to allow the project team (and third-party vendors) to get the remaining project work done. The earliest opportunity that the project may go live is October 2021.

In the interim, we will continue to operate under the two existing pipeline codes and will continue to use our existing OATIS system.

Relocation of the 402 Pipeline for Ports of Auckland

Firstgas is continuing work with the Ports of Auckland Limited (POAL) to finalise the detailed design for the relocation of the 402 pipeline at Te Rapa. It is expected the relocation of the pipeline will be completed in the latter part of summer in 2021.

POAL have purchased a block of land in Te Rapa just North of Hamilton. New Zealand Railways Main Trunk railway for the North Island runs through this land and POAL plan to turn the purchased land into an inland port. The land will provide both closed and open storage areas mainly for the storage of containers. NZ Rail intend to create three railway sidings off the main trunk line to facilitate access to the storage areas.

The Firstgas owned and operated 6" 402 line runs through the land that has been purchased by POAL. At present, the depth of cover over the pipeline is not of sufficient depth and the pipeline does not have sufficient protection to allow for the POAL development. The line must be realigned and lowered to allow the POAL works to progress.

The scope currently comprises construction and realignment of the 402 pipeline. Firstgas will complete the project phases using scheduled planning and regular integration meetings to be attended by all relevant project resources. Firstgas has engaged a third party to undertake detailed design works; Firstgas and the third party to work closely to ensure design is fit for purpose through the detailed design phase of this project.

Until recently the construction team have not had capacity to undertake the construction work, which impacted on the construction start date. The completion date has also been further impacted by the COVID-19 restrictions, which further impacted the schedule. Completion of the work is now planned to occur in the latter part of the summer in 2021.

The execution of a Limited Notice to Proceed (LNTP) agreement between Firstgas and POAL will allow for reimbursement of the project costs from POAL. Project costs are anticipated to be around $2 million.

Relocation of the 400 Pipeline at Murphys Road

Firstgas is working with a residential developer to finalise timing for the relocation of the 400 pipeline at Murphy's Road in Auckland.

A residential development is proceeding in the Flatbush area, with associated access ways within an area of land on Murphys Road in Flat Bush, Auckland.

Firstgas owns and operates the DN350 pipeline (the '400 Line'), which is currently in an easement that runs through a large portion of the area for development. The developer has requested that the pipeline be relocated to allow progression of the development.

The estimated cost to relocate the infrastructure of the 400 line for the Murphys Road Development is $4.5 million. As with all third party driven projects, Firstgas works with the stakeholders in a collaborative manner to deliver the project. As the project is driven by third party need, timelines for these types of project are often fluid.

Implementation of the compression strategy

As indicated in our previous AMPs, Firstgas has been undertaking a review of our compression needs on the transmission system. This has expanded from looking at individual compressor stations to reviewing the system as a whole.

The compression strategy was finalised in FY2020 and will see four of our key compression sites upgraded over the next 10 years – Rotowaro, the Kapuni gas treatment plant, Mokau compressor station and the Pohuru compressor station. The work will incorporate the construction and installation of the new modular compressor units, and modifications to the existing pipework to tie in the new units. The focus for FY2021 will be developing the FEED study for upgrades to the Rotowaro compressor station.

Our recent review[39] of transmission system compression requirements has identified that significant benefits can be realised by implementing a programme of upgrades to our existing compression fleet and operating the fleet as a single system.[40] We have subsequently developed a compression strategy that seeks to:

- Update and simplify an ageing fleet of compressor units, by utilising singular modular compression packages
- Minimise lifecycle capital and operational expenditure
- Improve reliability, security of supply and emergency response
- Provide flexibility to allow units to be relocated to match future changing system loads and opportunities
- Reduce asset integrity, security of supply and operational risks.

Shifting our focus from dealing with individual issues on compression sites to improvements across the network compression has resulted in a number of projects being cancelled:

- Planned replacements on the outdated pneumatic control systems at Rotowaro compressor station
- Replacement of the gas coolers at Pokuru
- Rewheeling of unit #1 Turbine at Mokau compressor station

By implementing the compression strategy, we can re-direct out investments to have an outcome that better suits our long-term asset planning.

39. The review was initiated in 2018 and was signalled in the 2019 AMP.
40. Historically the Maui and Non-Maui have been under separate ownership and considered as two systems for technical reviews.

Mangapukatea (White Cliffs) realignment

Firstgas undertook a technical review in early 2020 to consider the previous erosion and planning assumptions at the Mangapukatea erosion site (MES). The review was undertaken in order to recommend a way forward using existing and new information about the site. The 2020 technical review work has concluded that the pipelines are currently at a negligible risk and are unlikely to be exposed or damaged in the next 5 – 10 years

In line with the recommendations set out in the technical review, over the next 12 months Firstgas will:

- Continue to monitor the Mangapukatea erosion site
- Determine what essential works are required onsite to facilitate the future monitoring of the site

2020 technical review

This review involved the development of an erosion model, consultant engineering reviews of the MES geology, and a detailed review of all previous historical erosion reports to identify credible future erosion scenarios. Firstgas then assessed the risk and embedded the output of all the above into the erosion model, to develop project planning assumptions based on erosion triggers. AECOM[41] have subsequently completed a peer review of the conclusions and recommendations and confirm that the process followed by Firstgas is "robust, comprehensive and well executed."

The review included the development of erosion triggers to ensure that the realignment project proceeds accordingly as the risk escalates, and that the work can be completed in a planned way before the risk level escalates to a high level.

The development of an emergency response approach also allows for a fast response to be undertaken if the credible planning scenario is overtaken by an unprecedented event occurs.

On site monitoring of the erosion rate and evidence of episodic events must continue at the current frequency. Ground water monitoring equipment will be installed at the earliest opportunity to be able to continually apply the safe setback distances established by the review.

The erosion model will be assessed and baselined annually to establish whether the current planning assumption is still appropriate and will be updated with the current cliff proximity at the time, to calculate the anticipated project timeline from the new baseline. This also allows for any new erosion scenario to be considered. Any episodic events which exceed 5 metres recession will trigger a model review immediately and the impact on the planning assumptions will be considered.

Developing project stage triggers to respond to changes in the environment allows us to re-act in a timely fashion if large episodic events occur which have not been currently deemed credible. This will ensure that actions are taken to be able to respond to any scenario, within a timeframe that is deemed acceptable. These goals are defined as Project Response, Emergency Response and Black Swan Response.

This approach describes a resetting of trigger points for project initiation and more materially a change in pipeline replacement scope, which is much better aligned with the company mission of providing a safe and reliable gas supply which is affordable and acceptable to gas consumers.

Table 70: Credible planning scenarios for Mangapukatea site

PROJECT SCOPE	DESCRIPTION
Project Response	Ability to deliver the project according to the credible erosion scenario within a **5-year** planning and execution horizon
Emergency Response	Ability to deliver the project according to the unlikely erosion scenario as an emergency response within a **6-month** planning and execution horizon
Black Swan Response	Ability to deliver the project according to the highly unlikely erosion scenario as an emergency response within a **4-week** planning and execution horizon

41. AECOM is an infrastructure consulting firm.

Remediation of Pariroa land feature

An intelligent in line inspection survey undertaken in April 2018 identified a buckle in the 400 Line between Frankley Road Offtake and Mokau Compressor Station. Pariroa Phase 1 installed a temporary by-pass in December 2018. This Phase 2 project will provide the permanent solution and remove the by-pass.

Studies are near complete to enable concept scoping as we have the geotechnical report and a draft additional geotechnical report. The additional draft geotechnical report supports the earlier view of the simple repair to the damaged pipeline is all that is required to return to normal service. Additional drainage outside the easement area will almost certainly be required.

In the next months, scoping will start for the required remedial work scope, including options to avoid work outside easement should this be required due to access restrictions. However, if work is required outside of the easement, we would require access and consenting for Phase 2 which is expected to be delayed by landowner.

Considering the process with landowner occurs in a short timeframe, probably we would execute the engineering design during the summer 2020-2021.

Continuation of the Intelligent pigging programme

Firstgas conducts intelligent pigging, or in line inspections on piggable pipelines each year. This is an ongoing programme of work that is specified under our safety management study[42]. In FY2021 we are planning to complete intelligent pigging on a series of pipelines in Taranaki, between Fielding and Hastings and on the line that runs north of Auckland through to the Henderson compressor station.

Pipeline pigging or In Line Inspections (ILI) are a component of the Firstgas pipeline integrity management plan. The majority of the system, by length, is surveyed by ILI on a frequency as stipulated in the Safety Management Study for each pipeline.

The frequency of ILI surveys for piggable pipelines is typically set at 5 years for pipelines with elements in urban class locations, and 10 years for pipelines in exclusively rural class locations. These are default frequencies and each individual pipeline is further assessed during SMS to ensure that an appropriate frequency is set for each line. Frequency of pigging is also under consideration as part of the "ILI Survey and Cleaning Pigging Review" currently underway.

The assessment of pigging frequency is based on class, location, known condition of steel and coating, corrosion growth rate, line criticality and environmental factors.

Through the course of FY2021, we are planning to conduct a series of intelligent pigging at the following locations:

- 100 and 200 series pipelines that run north and south out of Taranaki
- 430 pipeline that runs north of Auckland to Henderson compressor station.
- 700 series pipelines between Feilding and Hasting.

Programme to upgrade PIG launchers and receivers

Firstgas has embarked on an initiative to upgrade our pigging facilities to ensure they are aligned with industry good practice. Part of this work involves upgrades to our pigging launchers and receivers. We are continuing with this planned programme of pigging facilities upgrades in FY2021.

PIG launchers and receivers are incorporated in stations[43] and facilitate the use of ILI survey tools. PIG receivers also act to contain and facilitate safe disposal of debris which is removed from the pipeline by PIGs.

ILI tools can carry-out a number of non-destructive examinations in live pipelines. Depending on the required application the tooling will be available in varying configurations.

The launchers and receiving traps are required to safely launch and recover, cleaning pigs and ILI tools, and are designed to minimise risk to operators.

ILI tooling has changed over recent years to accommodate the latest technology and allow for multi-tooling to avoid having to run multiple tools. This improved technology has resulted in longer ILI tools.

The programme to upgrade the launchers and receivers has been developed to modify or replace existing assets to ensure we can adopt the improved ILI technology as well and modify the pig traps to align with good practice in terms of ensuring operator safety when recovering or launching the tools.

A launcher and receiver facilities design guide has been developed to provide design guidance for new traps or modification to existing traps. The replacement or modification of traps has been assessed on a case by case basis. The recommendations made have considered factors such as current trap operability and suitability for use with nominated reporting tool, cost and ILI timeline. The program typically modifies the pig traps prior to the next ILI campaign for a particular pipeline, so that we can benefit for using the latest in ILI technology.

42. A Safety Management Study (or SMS) is a central part of the overall safety management process and is a prerequisite of maintaining a pipeline certificate of fitness. More on Firstgas' SMS is available in Appendix H.
43. PIG launchers and receivers may be incorporated in Compressor stations, delivery or receipt points, or dedicated PIG launcher and receiver stations

SCADA RTU CPU replacement programme

Firstgas is undertaking a programme of work to replace the central processing units (CPU) in its SCADA remote terminal units (RTU). This work has been prioritised as vendor support will end for the current CPU in 2021.

This project is to replace the SCADA Remote Terminal Units (RTU) CPU which were introduced to monitor the gas transmission pipeline in 2005. The vendor, Schneider, has issued a notice that the currently installed CPU model will not be supported after 2021. There are 33 SCADA sites affected. The current SCADA RTU CPU model SCD5200 is reliable but reaching product end life. Vendor support will not be available, nor will there be the availability of the existing hardware product after 2021. It is proposed that the existing SCADA sites are upgraded to the latest SCD6000 CPU. It is estimated that replacing the RTU CPU will provide support to, and increase the life cycle of, the RTU product through to 2032.

This equipment is compatible with future strategies for SCADA upgrade/replacements and with other foreseeable technology options. The CPU replacement programme will address the risk before obsolescence becomes an issue. It is expected that the migration will take between 12 and 18 months to complete the site works.

Heating systems replacement programme

Firstgas has initiated a programme to replace aging water bath heaters (WBH) across the transmission system. The replacement programme ensures that we are compliant with our pressure equipment management plan and standard AS3814 for WHB above 275kW.

Many of our WBH are nearing end of useful life. Gas-fired and electric WBH on the Firstgas transmission network were typically installed at the time of Delivery Point or station construction. Many have been in place since the transmission pipelines were first installed and maintained since that time. Further units have been progressively added over the years, as more Delivery Points have been added to the network.

Although we have had a refurbishment programme in effect for 10 years, the programme only considered the pressure containing components and the WBH shell. Advances in burner efficiency and technology means that we have now adapted our strategy, to incorporate these elements of the heaters. We have adopted a replacement programme for our common sized heaters. The WBH replacement programme will be in effect for the full planning period.

Appendix C provides background on the WBH on our transmission system and the age profile of these assets.

Warkworth expansion project

The Warkworth area is expanding and we anticipate an increasing demand for natural gas in this area. Firstgas will be conducting a FEED study over the course of the next few months to understand the requirements needed to meet expected increased demand from customers in the Warkworth area

The Warkworth expansion project has been on the horizon for a number of years. Gas demand growth in the region is dependent on two factors: the area is forecast to be a residential growth area; and the area also houses an agricultural glasshouse. In order to meet the increase in domestic demand and an increase in commercial demand, we will be required to upgrade the existing pipeline and delivery point.

The 432 line is a 2-inch pipeline that supplies the Warkworth 2 Delivery Point. The agriculture glass house is the biggest single consumer in Warkworth, using gas to make hot water for heating, and (clean) flue gases as a source of CO2 to enhance plant growth. They need to be assured that the gas delivery infrastructure can deliver the additional gas.

The main constraint for the area is the small diameter of the lateral pipeline, which limits the available capacity. Our assets operate within an optimum window if we start operating outside of that window the result can be that we are unable to maintain a reliable supply. It is likely that in order to meet the long-term demand from the Warkworth area the pipeline will need to be increased. Over the course of the next few months a FEED study will be undertaken to understand the expansion requirements needed.

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 2012* (consolidated as at 3 April 2018).

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE 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 this determination. (d) contains the information set out in in the schedules described in clause 2.6.6. (e) contains the Report on Asset Management Maturity as described in Schedule 13. (2) Complete the Report on Asset Management Maturity in accordance with the requirements specified in Schedule 13. (3) Publicly disclose the AMP.	1(a) Section 1 of the AMP summary document explains the scope of the AMP and states the AMP relates to Firstgas' gas transmission system. 1(b) and 1(c) Compliance with clause 2.6.2 and **Attachment A** of the Determination is summarised in the AMP summary document and explained in detail in appendices to the document as noted below. 1(d) The schedules required in clause 2.6.6 are included in **Appendix B** of the AMP and provided to the Commission in excel 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** (network overview) provides information on the condition of asset fleet. 1(e) The AMMAT report is included in **Appendix B** of the AMP. 2. Our approach to asset management is described in sections 2, 3 and 4 of the AMP summary document. Further detail on our asset management approach is provided in **Appendix H** and the AMMAT report is included in **Appendix B** of the AMP. 3. The AMP and its appendices are publicly available on Firstgas' website (www.firstgas.co.nz).

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
Disclosure relating to asset management plans and forecast information	
2.6.2 The purposes of AMP disclosure referred to in subclause 2.6.1(1)(b) are that the AMP: (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. (2) Must be capable of being understood by interested persons with a reasonable understanding of the management of infrastructure assets. (3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks.	1. (a) - (c) The AMP includes the following information: – The purpose of our AMP is outlined in section 1 of the AMP summary document – Sections 2,3 and 4 of our AMP summary document include discussion of our asset management improvement programme. This explains our approach to how we manage assets throughout the life cycle and how we maximise cost and performance efficiencies. More detail on our asset management approach is provided in **Appendix H**. – Section 3 3 of the AMP summary document outlines our system development work completed in FY2019, while section 4 comments on significant projects planned for 2020. Further detail on our system development programme for the 10-year planning period is available in **Appendix F** – System Development. – Performance Measures and Targets are included in section 3 of the AMP summary document and in **Appendix H**. 2. The AMP has been structured and presented in a manner that is intended to be easier for persons with a reasonable understanding of the management of infrastructure assets to understand. This includes: – The the detail of the asset management plan is now 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 in a glossary in **Appendix A** to assist understanding of terminology used in the AMP. – Clear description of expenditure forecasts presented in the AMP. 3. Risk management policy, framework and high-level risks are discussed in sections 2 of the AMP summary document and as part of our approach to asset management in sections 3 and 4. We discuss the path between asset criticality and health, risk mitigation and resulting expenditure. Further detail on our approach to risk management is discussed in **Appendix H** (asset management approach), while detailed asset related risks and issues are discussed in **Appendix C** (network overview).
Clauses 2.6.3 to 2.6.5 relate to AMP updates.	N / A as Firstgas has provided a full AMP this year.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION		AMP SECTION WHERE ADDRESSED
Disclosure relating to asset management plans and forecast information		
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 section 5 of the AMP summary document. Discussion on asset condition and demand are included in the AMP summary document where relevant. The required reports are included in **Appendix B** of the AMP and have been provided to the Commerce Commission in native format.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
Attachment A: Asset Management Plans	
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.	Our asset management approach is aligned to the Firstgas vision and strategy. This is summarised in sections 1 and 2 of the AMP summary document. These sections explain our corporate objectives, purpose of the AMP in meeting those objectives and governance over asset management decisions. We discuss our asset management improvement programme in sections 2, 3 and 4. In section 3, a diagram is provided giving an overview of the asset management framework. This shows the line of site from our strategic plan through to our asset management system and life cycle delivery. Key performance indicators are included in section 3. For more detail, **Appendix H** describes our asset management approach. **Appendix H**: – Outlines our asset management approach and the performance measures for the network, including targets. – Discusses our performance measures and AMMAT results, along with providing details about our approach to continuous improvement and defining several improvement initiatives. – Describes our 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. – Discusses optimisation of asset performance. – Discusses total lifecycle management approach. – Discusses the considerations for deferring asset purchase or renewal/replacement. As part of asset management, we need to understand the assets we own, their location and condition. In the AMP appendices we provide: – An overview of our network configuration and fleet, including fleet condition, in **Appendix C**. – Further information on asset condition, including age, and configuration are included in **Appendix D** (asset details) and **Appendix E** (system schematics).

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
Attachment A: Asset Management Plans	
AMP Design	
2. The disclosure requirements are designed to produce AMPs that: 2.1 Are based on, but are not limited to, the core elements of asset management identified in clause 1. 2.2 Are clearly documented and made available to all stakeholders. 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. 2.4 Specifically support the achievement of disclosed service level targets. 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. 2.6 Consider the mechanics of delivery including resourcing. 2.7 Consider the organisational structure and capability necessary to deliver the AMP. 2.8 Consider the organisational and contractor competencies and any training requirements. 2.9 Consider the systems, integration and information management necessary to deliver the plans. 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. 2.11 Promote continual improvements to asset management practices.	2.1 The elements identified in clause 1 are discussed above. 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 Our asset management practices and our self-assessment against the AMMAT principles are discussed in sections 2, 3 and 4 of the AMP summary document. Further detail is provided in Appendix H. 2.4 Our performance measures and target levels are defined in **Appendix H**. 2.5 Our approach to risk management is discussed in section 2 and 4 of the AMP summary document. A fuller view of our approach to risk management is discussed in **Appendix H**. **Appendix C** considers risks more specifically focussed on Assets along with opportunities and projects related to performance improvements. 2.6 As part of our asset management framework and system, as described in section 3 of the summary document, we consider our planning and scheduling. A key part of this is ensuring we have the resources available to deliver on our asset management plans and objectives. Our delivery model, including consideration of resourcing, is discussed in **Appendix H**. 2.7 The organisational structure in relation to the delivery and responsibilities of the AMP are included in Section 1 of the AMP summary document. Refer **Appendix H** for more detail. 2.8 **Appendix H** outlines competency and training requirements. 2.9 Asset management systems, integration and information management are outlined in sections 2, 3 and 4 of the AMP summary, and further detailed in **Appendix H**. 2.10 Throughout the AMP we have used terminology and definitions consistent with those used in attachment A of the information disclosure determination and other disclosure documentation. We have included a definition of less common terms in a glossary in **Appendix A** and in the AMP summary document to assist understanding of the terminology used in the AMP. 2.11 Our AMMAT results are discussed in section 4 of the AMP summary document. **Appendix H** discusses our performance measures and AMMAT results. This appendix also describes our approach to continuous improvement and defining several improvement initiatives.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION		AMP SECTION WHERE ADDRESSED
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. – Our asset management framework and systems, and planned improvements in these areas. – A region 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 described in sections 22 – 4 of the AMP summary document. **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 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.	Section 1 of the AMP summary document outlines the statement of purpose of the AMP and the corporate focus for asset management. Section 3 provides an illustrative overview of our asset management framework showing how our asset management system, including the asset management plan, feeds into and out of Firstgas' strategic plan. The asset management policy and framework is outlined in greater detail in **Appendix H**. This appendix links the corporate vision and mission to the asset management approach. This appendix also describes how the different asset management plans and documentation relate to one another.
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 ten-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** lists the applicable legislations, regulations, and industry codes that affect the management of assets and describes how these requirements are incorporated into asset management.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION		AMP SECTION WHERE ADDRESSED
Contents of the AMP		
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.	Section 6 of the AMP summary document summarises our stakeholder engagement including how the needs and interests of our stakeholders are identified, and how we manage conflicting interests. The diagram of our asset management system in section 3 illustrates that our asset management policies, strategies and objectives reflect stakeholder needs. **Appendix H** provides greater detail on stakeholder interests and describes how: (1) Stake-holders needs are identified. (2) The interests of each of the key stakeholders are identified. (3) Stakeholder interests are accommodated into our decision making and asset management practices.
3.8	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including: 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.	Section 2 of the AMP summary document describes Firstgas' corporate and organisational structure. In greater detail, **Appendix H** describes: – Asset Management Governance and organisation 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. 3.9.3 a description of changes proposed where the information is not based on the GTB's existing business. 3.9.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information. 3.9.5 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 Forecast Operational Expenditure set out in Schedule 11b.	1) & (2) Key assumptions for the development of the AMP are outlined in **Appendix H**. Expenditure assumptions are outlined in **Appendix J**. (3) There are no changes proposed in this AMP where the information is not based on our current business. (4) **Appendix H** identifies sources of uncertainty and possible effects on the prospective information. It also describes methods of managing these uncertainties. (5) Escalation rates utilised for the purposes of disclosing nominal expenditure are included in **Appendix J**.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
Contents of the AMP	
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.	Section 4 of the AMP summary document discusses areas of focus for the upcoming 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 section 4. **Appendix H** identifies, in more detail, any sources of uncertainty and possible effects and describes methods of managing these uncertainties.
3.12 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 takes into account 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.*	Sections 2 – 4 of the AMP summary document include a narrative on our asset management approach and our asset management improvement programmes. These sections provide an overview of our asset management strategy, including how it aligns with our 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 our 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 discussed 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.*	Sections 2 – 4 of the AMP summary document includes a narrative on Firstgas' asset management programmes and the AMMAT disclosure. **Appendix H** provides a more detailed view of systems and information data supporting the AMMAT disclosure. Specifically, this appendix: (1) Defines the categorisation and relationships of asset management data and the related systems used to manage the lifecycle of our assets. (2) Identifies the systems used to manage asset data, including the condition and capacity of assets, and asset performance. (3) & (4) outlines asset data quality management processes, and system integration.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION		AMP SECTION WHERE ADDRESSED
Contents of the AMP		
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.*	Sections 3 and 4 of the AMP summary document include discussion of our asset management improvement programme. **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.	Section 4 of the AMP summary document discusses how we manage our asset life cycle delivery. The detail of the underlying processes is 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 2 of the AMP summary describes our approach to asset management. **Appendix H** describes the key components of the asset management system including documentation, controls and the review process. This includes: (1) The documentation describing the key components of the asset management system. (2) Structure and financial control. (3) Systems for retaining asset knowledge.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
Contents of the AMP	
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 our communication with key stakeholders on aspects of the AMP. In **Appendix H** we outline our: (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 FY18 New Zealand dollars as stated in **Appendix J**.
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.
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 our high-pressure transmission pipelines is provided in section 2 of the AMP summary document
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 stations is explained in **Appendix E**.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
Network Assets by Category	
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** includes an overview and quantity of each asset category.
6.5 Age profiles.	**Appendix C** includes age profiles and condition of assets.
6.5 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.	Section 2 of the AMP summary document discusses geohazards on our network that may affect when assets are replaced and section 4 lists the replacement projects occurring in the upcoming 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). Please 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 discussed in **Appendix C** are the same categories listed in the Report on Forecast Capital Expenditure in Schedule 11a (refer **Appendix B**).
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, taking into account expected demands on the transmission system and the GTB's investment plans.	System capacity and development planning is discussed in: – **Appendix F** (system development) – **Appendix G** (security of supply) – **Appendix I** (capacity determination)

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
Transmission system capacity	
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 / offtake capacity analysis is provided in **Appendix F**.
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**.
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**. This includes naming any software used for the modelling. Recent system peak flows are published on our 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.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
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.	Section 3 of the AMP summary document describes key performance indicators, results for 2019 and target. **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.	Section 3 of the AMP summary document includes a table of key performance indicators and trend. Firstgas has only operated the gas networks since 2016 and historic comparatives are limited. We have included historical performance values 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 I (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.*	Section 4 of the AMP summary document discusses the significant activities planned for the 2019 disclosure year. Development planning criteria are discussed in detail in **Appendix I**.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION		AMP SECTION WHERE ADDRESSED
Service Levels		
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** discusses 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 Section Appendix I.
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 taken into account 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 discussion on asset management improvements in sections 3 and 4 of the AMP summary document provides an overview of how all projects approved under the asset management system align with Firstgas' goals and vision. Section 3 notes the implementation of new tools in 2020 used for asset management through the lifecycle including a solution that helps prioritise project portfolio investments. Further information on load is available in **Appendix I** (capacity determination, including load forecasting methods) Constraints within the system **Appendix H** (asset management approach) discusses project prioritisation and the link back to the corporate investment prioritisation criteria.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
Service Levels	
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.	Section 4 of the AMP summary document discusses the significant projects for the upcoming 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.*	Section 4 of the AMP summary document describes the significant activities planned for 2020. Many of these activities or programmes of work extend further than a single year. A summary of total Capex expenditure is included in section 5. **Appendix F** (system development) and Appendix I (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** covers demand forecasts.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
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.	Our asset management system as illustrated in section 3 of the AMP summary document shows the line of sight from our 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. Section 4 highlights the roll out of our maintenance optimisation programme planned for this year. The key drivers for the asset maintenance are described in **Appendix H** (asset management approach) and **Appendix K** (maintenance schedules).
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.	Section 5 of the AMP summary document includes the budget for total opex over the planning period. **Appendix K** provides further detailed information on: – Routine inspections and maintenance. – Key risks and issues identified for each asset type – Categorised budgets 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.	Our approach to asset management is summarised in sections 2 – 4 of the AMP summary document. These sections highlight our view of asset health leading to investment (whether replacement or renewal) decisions. Key asset replacement projects undertaken in FY2020 are discussed in section 3 and key projects for the upcoming year are described in section 4 of the AMP summary document. Further detail is available in **Appendices H** and **C**. Our approach to asset replacement and renewal, and the drivers behind investment are described in **Appendix H**. Further detail on projects planned for the planning period (10 years) are described in **Appendix C**.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
Non-Network Development, Maintenance and Renewal)	
16. AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including:	Sections 2 – 4 of the AMP summary document describes our 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:	Section 2 of the AMP summary document provides information on our risk management for our transmission system. **Appendix H** 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**. Further detail on asset related risks are outlined in **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.	Section 2 of the AMP summary document considers how we address risks on our transmission system. **Appendix H** 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.	Section 2 of the AMP summary document considers how we manage risks on the network. Appendix H identifies the policy, and identifies the 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** outlines the emergency response and contingency plans.

2.6 ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP SECTION WHERE ADDRESSED
Evaluation of performance	
19. AMPs must provide details of performance measurement, evaluation, and improvement, including:	Performance measures are discussed 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.	Section 3 of the AMP summary document reviews the progress against plan for the prior year. Further detail on the progress of development projects and maintenance initiatives / programs 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 section 3 of the AMP summary document and in detail in **Appendix H**. Historical information for the years Firstgas has owned the transmission network is included for the key performance metrics in in **Appendix H**.
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 discusses the AMMAT gap analysis and how it is used to inform our asset management improvement programme. Improvement initiatives based on gaps in the AMMAT results are discussed in **Appendix H**.
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 discusses the AMMAT gap analysis and how it is used to inform our asset management improvement programme. Improvement initiatives based on gaps in the AMMAT results are discussed in **Appendix H**.
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.	Our asset management approach sets a line of site between our corporate strategy and life cycle management. Our approach to asset management is explained in sections 2 – 4 of the AMP summary document. This, alongside our governance and organisation structure outlined in section 2 ensures our AMP is realistic and the objectives are achievable. Appendix H describes the governance and framework to achieve a realistic AMP in greater detail.
20.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	Section 2 of the AMP summary document describes the governance and framework of the AMP, as well as the organisational structure that supports the implementation of the AMP. **Appendix H** describes the governance and framework of the AMP.

APPENDIX N: DIRECTOR 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.

(c) The forecasts in Schedules 11a, 11b, 12a, 12b and 12c 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

12 August 2020

Date

Director: Fiona Ann Oliver

12 August 2020

Date