Firstgas

AMP Appendices

Transmission

30 September 2025

Introduction

This document sets out a set of appendices to the Firstgas gas transmission asset management plan (AMP) for 2025, which can be found here.

The structure of the 2025 AMP appendices is set out in the following table.

AMP Appendices

Appendices		Description
A	**Glossary**	Sets out key terms and abbreviations
B	**Information disclosure schedules**	AMP disclosure schedules required by Commerce Commission
C	**Asset management approach**	Overview of our approach to asset management
D	**Lifecycle management**	Explains our lifecycle-focused approach to managing our transmission assets
E	**Network development**	Explains our approach to developing our transmission network
F	**Compliance schedule**	Sets out how the AMP addresses relevant Information Disclosure requirements
G	**Director certificate**	A copy of the AMP's director certification

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Appendix A. Glossary

Term	Definition
AC	Alternating current
AI	Artificial intelligence
ALARP	As low as reasonably practicable
AMMAT	Asset management maturity assessment tool
AMP	Asset management plan
AMS	Asset management system
Anomaly	Discontinuity or imperfection of the pipe wall
BGIX	Balancing gas information exchange
Capex	Capital expenditure – expenditure used to create new or upgrade existing assets
CIMS	Coordinated incident management system
CCO	Critical contingency operator
COTS	Commercial off the shelf – terminology for technology solutions that are ready-made, vendor-supported products that can be configured or customised to meet specific organisational needs
CP	Cathodic protection
CPI	Consumer price index
CPP	Customised price path
DCVG	Direct current voltage gradient – survey technique used for assessing the effectiveness of corrosion protection on buried steel pipelines
Defect	Discontinuity or imperfection of the pipe wall of sufficient magnitude to warrant rejection based on the requirements of an appropriate fitness–for–service analysis
DFA	Delegated financial authority
DP	Delivery point – station where gas exits the transmission network to enter a distribution network or customer facility
DPP	Default price-quality path
EMAT	Electromagnetic acoustic transducer.
FY26	Financial year 2026 – our financial year from 1 October 2025 to 30 September 2026
GC	Gas chromatograph
GDB	Gas distribution business
GIS	Geographic information system – Software designed to present, manipulate and analyse spatial data
GJ	Gigajoule
GTB	Gas transmission business
ICT	Information communications technology – refers to hardware and digital systems, networks, and technologies used to collect, store, process, transmit, and manage data
ILI	In line inspection – 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 anomalies
IT	Information technology
KGTP	Kapuni gas treatment plant
KPI	Key performance indicator

Term	Definition
MAOP	Maximum allowable operating pressure
Measurement length	The radius of the 4.7 kW/m^2 thermal radiation contour (threshold for injury after 30 seconds exposure) for an ignited rupture at any point along the pipeline route
MLV	Main line valve - valve installed on transmission pipelines used for isolating pipelines
OATIS	Open access transmission information system – platform for managing nominations, contracts, billing, metering data, and information exchange across the gas transmission network
OEM	Original equipment manufacturer
Opex	Operational expenditure
Pig	Pipeline inspection gauge tool – device pushed down a pipeline to internally clean pipelines and/or measure its wall thickness and integrity
Pigging	Operation terminology when using a pig to internally inspect, clean, or gauge pipelines during operation to assess their condition
PLC	Programmable logic controller – industrial computer that utilises inputs and outputs to operate logic-based software for automated processes or machines
PSV	Pressure safety valve - device to relieve excessive pressure in system to protect equipment, also known as pressure relief valve
RCMI	Routine corrective maintenance inspection
SaaS	Software as a solution
SAMP	Strategic asset management plan
SCADA	Supervisory control and data acquisition – computer system for operating assets and analysing real time operational data
SCC	Stress corrosion cracking occurs when corrosion combines with tensile stress, leading to environmentally assisted cracking in pipelines
SCMH	Standard cubic meters per hour
SIE	Service interruptions emergencies
SFAIRP	So far as is reasonably practicable
SMS	Safety management study

Appendix B. Disclosure Schedules

This section 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

Firstgas' approach to forecast escalation is explained in Schedule 14a. This provides an explanation for differences between nominal and constant price capital expenditure forecasts (Schedule 11a) and operational expenditure (Schedule 11b).

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Schedule 11a – report on forecast capital expenditure

11a(i): Expenditure on Assets Forecast

Category	RY25 $000 (nominal)	RY26 $000 (nominal)	RY27 $000 (nominal)	RY28 $000 (nominal)	RY29 $000 (nominal)	RY30 $000 (nominal)	RY31 $000 (nominal)	RY32 $000 (nominal)	RY33 $000 (nominal)	RY34 $000 (nominal)	RY35 $000 (nominal)
Consumer connection	-	-	-	-	-	-	-	-	-	-	-
System growth	473	256	366	374	382	390	399	408	417	426	435
Asset replacement and renewal	34,265	24,778	29,726	32,393	33,230	28,713	24,747	18,569	19,323	18,978	14,209
Asset relocations	558	3,682	3,959	4,046	3,343	3,417	3,501	3,578	3,656	3,737	3,819
Quality of supply	174	2,388	-	-	-	-	-	-	-	-	-
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other Reliability, Safety and Environment	1,121	1,804	425	381	424	657	443	377	385	393	402
Total reliability, safety and environment	**1,295**	**4,191**	**425**	**381**	**424**	**657**	**443**	**377**	**385**	**393**	**402**
Expenditure on network assets	**36,592**	**32,906**	**34,476**	**37,194**	**37,379**	**33,176**	**29,089**	**22,931**	**23,781**	**23,533**	**18,865**
Expenditure on non-network assets	3,330	3,386	5,355	4,762	2,951	3,552	2,989	3,055	3,885	3,249	3,503
Expenditure on assets	**39,921**	**36,292**	**39,831**	**41,957**	**40,330**	**36,728**	**32,078**	**25,986**	**27,666**	**26,782**	**22,369**
Cost of financing	867	726	798	843	821	740	636	501	536	515	417
Value of capital contributions	502	3,313	3,563	3,642	3,009	3,075	3,150	3,220	3,291	3,363	3,437
Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
Capital expenditure forecast	**40,286**	**33,704**	**37,065**	**39,158**	**38,142**	**34,393**	**29,564**	**23,267**	**24,911**	**23,935**	**19,348**
Assets commissioned	56,431	34,992	36,407	38,749	38,341	35,127	30,509	24,499	24,589	24,126	20,246

11a(i): Expenditure on Assets Forecast

Category	RY25 $000 (constant)	RY26 $000 (constant)	RY27 $000 (constant)	RY28 $000 (constant)	RY29 $000 (constant)	RY30 $000 (constant)	RY31 $000 (constant)	RY32 $000 (constant)	RY33 $000 (constant)	RY34 $000 (constant)	RY35 $000 (constant)
Consumer connection	-	-	-	-	-	-	-	-	-	-	-
System growth	473	250	350	350	350	350	350	350	350	350	350
Asset replacement and renewal	34,265	24,244	28,460	30,346	30,460	25,752	21,718	15,946	16,236	15,602	11,431
Asset relocations	558	3,602	3,791	3,791	3,064	3,064	3,072	3,072	3,072	3,072	3,072
Quality of supply	174	2,336	-	-	-	-	-	-	-	-	-
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other Reliability, Safety and Environment	1,121	1,765	407	357	389	589	389	323	323	323	323
Total reliability, safety and environment	**1,295**	**4,101**	**407**	**357**	**389**	**589**	**389**	**323**	**323**	**323**	**323**
Expenditure on network assets	**36,592**	**32,198**	**33,007**	**34,844**	**34,263**	**29,756**	**25,529**	**19,691**	**19,981**	**19,348**	**15,176**
Expenditure on non-network assets	3,330	3,313	5,127	4,462	2,705	3,186	2,623	2,623	3,264	2,671	2,818
Expenditure on assets	**39,921**	**35,511**	**38,134**	**39,305**	**36,968**	**32,941**	**28,152**	**22,314**	**23,245**	**22,019**	**17,994**
Research and development	-	-	-	-	-	-	-	-	-	-	-

11a(i): Difference between nominal and constant price forecasts

Category	RY25 $000 (difference)	RY26 $000 (difference)	RY27 $000 (difference)	RY28 $000 (difference)	RY29 $000 (difference)	RY30 $000 (difference)	RY31 $000 (difference)	RY32 $000 (difference)	RY33 $000 (difference)	RY34 $000 (difference)	RY35 $000 (difference)
Consumer connection	-	-	-	-	-	-	-	-	-	-	-
System growth	-	6	16	24	32	40	49	58	67	76	85
Asset replacement and renewal	-	533	1,266	2,047	2,770	2,960	3,029	2,624	3,087	3,375	2,779
Asset relocations	-	79	169	256	279	352	428	505	584	665	747
Quality of supply	-	51	-	-	-	-	-	-	-	-	-
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other Reliability, Safety and Environment	-	39	18	24	35	68	54	53	62	70	79
Total reliability, safety and environment	**-**	**90**	**18**	**24**	**35**	**68**	**54**	**53**	**62**	**70**	**79**
Expenditure on network assets	**-**	**708**	**1,468**	**2,351**	**3,116**	**3,420**	**3,561**	**3,240**	**3,800**	**4,186**	**3,689**
Expenditure on non-network assets	-	73	228	301	246	366	366	432	621	578	685
Expenditure on assets	**-**	**781**	**1,696**	**2,652**	**3,362**	**3,787**	**3,927**	**3,672**	**4,420**	**4,764**	**4,375**

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11a(ii): Consumer Connection

GTB connection type	RY25 $000 (constant)	RY26 $000 (constant)	RY27 $000 (constant)	RY28 $000 (constant)	RY29 $000 (constant)	RY30 $000 (constant)
Consumer connection expenditure						
Capital contributions funding consumer connection						
Consumer connection less capital contributions						

11a(iii): System Growth

	RY25 $000 (constant)	RY26 $000 (constant)	RY27 $000 (constant)	RY28 $000 (constant)	RY29 $000 (constant)	RY30 $000 (constant)
Pipes	-	250	350	350	350	350
Compressor stations	-	-	-	-	-	-
Other stations	473	-	-	-	-	-
SCADA and communications	-	-	-	-	-	-
Special crossings						
System growth expenditure	**473**	**250**	**350**	**350**	**350**	**350**
Capital contributions funding system growth						
System growth less capital contributions	**473**	**250**	**350**	**350**	**350**	**350**

11a(iv): Asset Replacement and Renewal

	RY25 $000 (constant)	RY26 $000 (constant)	RY27 $000 (constant)	RY28 $000 (constant)	RY29 $000 (constant)	RY30 $000 (constant)
Pipes	8,859	14,558	10,380	13,744	17,802	17,769
Compressor stations	14,400	4,179	9,301	10,301	5,934	1,934
Other stations	3,486	1,565	1,593	1,593	1,665	1,665
SCADA and communications	5,756	2,114	3,850	3,025	2,425	2,425
Special crossings	1	249	260	-	-	-
Stations - main-line valves	118	20	265	265	605	605
Stations - heating system	1,080	901	480	110	779	804
Stations - odorisation plants	89	130	1,468	529	1,000	120
Stations - coalescers	-	-	35	35	-	-
Stations - metering system	417	398	318	235	149	280
Stations - cathodic protection	59	130	410	410	-	50
Stations - chromatographs	-	-	100	100	100	100
Asset Replacement and Renewal expenditure	**34,265**	**24,244**	**28,460**	**30,346**	**30,460**	**25,752**
Capital contributions funding asset renewal						
Asset renewal less capital contributions	**34,265**	**24,244**	**28,460**	**30,346**	**30,460**	**25,752**

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11a(v): Asset Relocations

Project or programme	RY25 $000 (constant)	RY26 $000 (constant)	RY27 $000 (constant)	RY28 $000 (constant)	RY29 $000 (constant)	RY30 $000 (constant)
All other projects or programmes - asset relocations	558	3,602	3,791	3,791	3,064	3,064
Asset Relocations expenditure	**558**	**3,602**	**3,791**	**3,791**	**3,064**	**3,064**
Capital contributions funding asset relocations	502	3,242	3,412	3,412	2,758	2,758
Asset Relocations less capital contributions	**56**	**360**	**379**	**379**	**306**	**306**

11a(vi): Quality of Supply

Project or programme	RY25 $000 (constant)	RY26 $000 (constant)	RY27 $000 (constant)	RY28 $000 (constant)	RY29 $000 (constant)	RY30 $000 (constant)
All other projects or programmes - quality of supply	174	2,336				
Quality of supply expenditure	**174**	**2,336**				
Capital contributions funding quality of supply						
Quality of supply less capital contributions	**174**	**2,336**				

11a(vii): Legislative and Regulatory

Project or programme	RY25 $000 (constant)	RY26 $000 (constant)	RY27 $000 (constant)	RY28 $000 (constant)	RY29 $000 (constant)	RY30 $000 (constant)
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure						
Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions						

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

Project or programme	RY25 $000 (constant)	RY26 $000 (constant)	RY27 $000 (constant)	RY28 $000 (constant)	RY29 $000 (constant)	RY30 $000 (constant)
All other projects or programmes - other RSE	1,121	1,765	407	357	389	589
Other reliability, safety and environment total	**1,121**	**1,765**	**407**	**357**	**389**	**589**
Capital contributions funding other RSE						
Other RSE less capital contributions	**1,121**	**1,765**	**407**	**357**	**389**	**589**

11a(ix): Non-Network Assets

Project or programme	RY25 $000 (constant)	RY26 $000 (constant)	RY27 $000 (constant)	RY28 $000 (constant)	RY29 $000 (constant)	RY30 $000 (constant)
Routine - ICT	1,268	685	2,232	2,232	732	1,219
Routine - buildings and facilities	675	483	1,027	600	475	394
Routine - plant and equipment	724	1,633	865	627	495	570
Routine - motor vehicle procurement	663	512	1,003	1,003	1,003	1,003
All other projects or programmes - routine expenditure						
Routine expenditure	**3,330**	**3,313**	**5,127**	**4,462**	**2,705**	**3,186**
Atypical expenditure						
Atypical expenditure						
Atypical expenditure						
Atypical expenditure						
Atypical expenditure						
All other projects or programmes - atypical expenditure						
Atypical expenditure	**-**	**-**	**-**	**-**	**-**	**-**
Expenditure on non-network assets	**3,330**	**3,313**	**5,127**	**4,462**	**2,705**	**3,186**

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Schedule 11b – report on forecast operational expenditure

11b: Expenditure on Assets Forecast

Category	RY25 $000 (nominal)	RY26 $000 (nominal)	RY27 $000 (nominal)	RY28 $000 (nominal)	RY29 $000 (nominal)	RY30 $000 (nominal)	RY31 $000 (nominal)	RY32 $000 (nominal)	RY33 $000 (nominal)	RY34 $000 (nominal)	RY35 $000 (nominal)
Service interruptions, incidents and emergencies	772	1,261	1,289	1,317	1,346	1,376	1,406	1,437	1,468	1,501	1,534
Routine and corrective maintenance and inspect	18,482	18,429	20,944	21,693	22,225	22,825	23,726	24,365	25,139	25,935	26,754
Asset replacement and renewal											
Compressor fuel	4,466	6,000	-	-	-	-	-	-	-	-	-
Land management and associated activity	1,988	2,044	2,089	2,135	2,182	2,230	2,279	2,329	2,381	2,433	2,486
Network opex	**25,709**	**27,734**	**24,322**	**25,145**	**25,753**	**26,431**	**27,411**	**28,131**	**28,988**	**29,869**	**30,775**
System operations	3,288	3,454	3,686	3,803	3,924	4,049	4,178	4,311	4,448	4,589	4,735
Network support	8,350	9,915	10,066	10,608	10,841	11,136	11,381	11,689	11,946	12,209	12,478
Business support	26,341	26,921	29,302	30,079	30,705	31,331	32,021	32,726	33,446	34,182	34,934
Non-network opex	**37,979**	**40,289**	**43,055**	**44,490**	**45,470**	**46,516**	**47,580**	**48,726**	**49,840**	**50,980**	**52,147**
Operational expenditure	**63,688**	**68,023**	**67,377**	**69,636**	**71,223**	**72,947**	**74,991**	**76,857**	**78,828**	**80,849**	**82,921**

11b: Expenditure on Assets Forecast

Category	RY25 $000 (constant)	RY26 $000 (constant)	RY27 $000 (constant)	RY28 $000 (constant)	RY29 $000 (constant)	RY30 $000 (constant)	RY31 $000 (constant)	RY32 $000 (constant)	RY33 $000 (constant)	RY34 $000 (constant)	RY35 $000 (constant)
Service interruptions, incidents and emergencies	772	1,234	1,234	1,234	1,234	1,234	1,234	1,234	1,234	1,234	1,234
Routine and corrective maintenance and inspect	18,482	18,032	20,052	20,322	20,372	20,472	20,822	20,922	21,122	21,322	21,522
Asset replacement and renewal											
Compressor fuel	4,466	5,870	-	-	-	-	-	-	-	-	-
Land management and associated activity	1,988	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Network opex	**25,709**	**27,137**	**23,286**	**23,556**	**23,606**	**23,706**	**24,056**	**24,156**	**24,356**	**24,556**	**24,756**
System operations	3,288	3,379	3,529	3,563	3,597	3,632	3,666	3,702	3,737	3,773	3,809
Network support	8,350	9,702	9,638	9,938	9,938	9,988	9,988	10,038	10,038	10,038	10,038
Business support	26,341	26,341	28,054	28,178	28,145	28,101	28,102	28,102	28,102	28,102	28,102
Non-network opex	**37,979**	**39,422**	**41,221**	**41,679**	**41,680**	**41,720**	**41,756**	**41,841**	**41,876**	**41,912**	**41,949**
Operational expenditure	**63,688**	**66,559**	**64,507**	**65,235**	**65,286**	**65,426**	**65,812**	**65,997**	**66,233**	**66,469**	**66,705**
Research and Development	-	-	-	-	-	-	-	-	-	-	-
Insurance	-	-	-	-	-	-	-	-	-	-	-

11b: Difference between nominal and constant price forecasts

Category	RY25 $000 (difference)	RY26 $000 (difference)	RY27 $000 (difference)	RY28 $000 (difference)	RY29 $000 (difference)	RY30 $000 (difference)	RY31 $000 (difference)	RY32 $000 (difference)	RY33 $000 (difference)	RY34 $000 (difference)	RY35 $000 (difference)
Service interruptions, incidents and emergencies	-	27	55	83	112	142	172	203	235	267	300
Routine and corrective maintenance and inspect	-	397	892	1,371	1,853	2,353	2,904	3,443	4,017	4,613	5,232
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Compressor fuel	-	129	-	-	-	-	-	-	-	-	-
Land management and associated activity	-	44	89	135	182	230	279	329	380	433	486
Network opex	**-**	**597**	**1,036**	**1,589**	**2,147**	**2,725**	**3,355**	**3,975**	**4,632**	**5,313**	**6,018**
System operations	-	74	157	240	327	417	511	609	711	816	926
Network support	-	213	429	670	904	1,148	1,393	1,652	1,909	2,172	2,440
Business support	-	580	1,248	1,901	2,560	3,230	3,920	4,624	5,344	6,080	6,832
Non-network opex	**-**	**867**	**1,834**	**2,812**	**3,791**	**4,796**	**5,824**	**6,885**	**7,963**	**9,068**	**10,198**
Operational expenditure	**-**	**1,464**	**2,870**	**4,401**	**5,938**	**7,521**	**9,179**	**10,859**	**12,595**	**14,380**	**16,216**

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Schedule 12a – report on asset condition

12a: Report on Asset Condition

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
Pipes	Protected steel pipes	km		1%	38%	61%	1%	3	-
Pipes	Special crossings	km			43%	57%		3	-
Stations	Compressor stations	No.		33%	67%			3	-
Stations	Offtake point	No.			97%	3%		3	-
Stations	Scraper stations	No.			100%			3	-
Stations	Intake points	No.			100%			3	-
Stations	Metering stations	No.			100%			3	-
Compressors	Compressors—turbine driven	No.	25%	25%	50%			3	-
Compressors	Compressors—electric motor driven	No.			100%			3	-
Compressors	Compressors—reciprocating engine driven	No.	43%	29%	14%	14%		3	14%
Main-line valves	Main line valves manually operated	No.	3%	38%	56%	2%		3	-
Main-line valves	Main line valves remotely operated	No.			100%			3	-
Heating systems	Gas-fired heaters	No.			69%	31%		3	-
Heating systems	Electric heaters	No.			100%			3	-
Odorisation plants	Odorisation plants	No.			100%			3	8%
Coalescers	Coalescers	No.	6%		94%			3	-
Metering systems	Meters—ultrasonic	No.	80%		20%			3	-
Metering systems	Meters—rotary	No.	4%	22%	64%	6%	4%	3	26%
Metering systems	Meters turbine	No.	4%	9%	70%	14%	4%	3	12%
Metering systems	Meters—mass flow	No.			100%			3	-
SCADA and communications	Remote terminal units (RTU)	No.	1%	82%	12%	3%	1%	3	83%
SCADA and communications	Communications terminals	No.	67%		33%			3	33%
Cathodic protection	Rectifier units	No.	4%	8%	67%	17%	4%	3	4%
Chromatographs	Chromatographs	No.		54%	38%		8%	3	-

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Schedule 12b – report on forecast demand

12b(i): Connections

Category	RY25	RY26	RY27	RY28	RY29	RY30
[GTB connection type]*	-	-	-	-	-	-
[GTB connection type]*	-	-	-	-	-	-
[GTB connection type]*	-	-	-	-	-	-
[GTB connection type]*	-	-	-	-	-	-
[GTB connection type]*	-	-	-	-	-	-
Connections total						

12b(ii): Gas conveyed

Category	RY25	RY26	RY27	RY28	RY29	RY30
Intake volume (TJ)	97,377	87,084	85,347	82,135	80,848	79,597
Quantity of gas delivered (TJ)	96,834	86,650	84,915	81,636	80,353	79,107
Gas used in compressor stations (TJ)	404	402	400	398	396	394
Gas used in heating systems (TJ)	93	75	73	71	69	67
Total gas conveyed (TJ)	**97,332**	**87,127**	**85,388**	**82,105**	**80,818**	**79,568**

Schedule 13 – report on AMMAT

13(i): Asset Management Capability, Self Assessment Questions

Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information	Assessed maturity level
3	**Asset management policy**	To what extent has an asset management policy been documented, authorised and communicated?	3	Firstgas has a published AM Policy available through the Nucleus document management system	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.	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.
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?	2	Strategic asset management plan (SAMP) is under development and previous asset strategies require updates to suit current and future operations. Evidence of some disconnection to organisation objectives.	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.	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.
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?	2	Some assets strategies are present, while other asset require strateggies to be developed. Lifecycle strategies for some assets require updates to suit current and future operating environment.	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.
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?	2	Asset strategy documents are in place for most assets. Additional asset strategies are required to be created and existing strategies are required to be aligned with SAMP and business objectives. An overview of asset lifecycle management is document in our asset management plan.	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).	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.
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	Regular meetings and presentations from general and senior managers about the need to update current asset strategies has improved communication of plans. Yearly stakeholder presentation and social media promotion captures wider audience.	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.	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.
29	**Asset management plan(s)**	How are designated responsibilities for delivery of asset plan actions documented?	3	The Chief Operating Officer is responsible for the delivery of the asset management plans. Asset engineers are responsible for maintaining plans and asset planning for ensuring plans are being executed. These responsibilities are documented in 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.	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.
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)	2	Firstgas has implemented integrated activity planning, coordinating the delivery of all field work. Utilisation of internal staff and established contractors are used to execute plans. Further refinements are required in the scheduling process to reduce clashes.	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.	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.
33	**Contingency planning**	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Firstgas has comprehensive Emergency response plans and crisis management plans to respond to incidents and emergencies. The plans are aligned to the New Zealand Coordinated Incident Management System.	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.	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.
37	**Structure, authority and responsibilities**	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Firstgas has appointed staff who have 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.	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.

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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	Integrated activity plan, project execution and maintenance KPIs track the completion of work against the schedules and identifies resource constraints, including specialist vendors, tools and equipment.	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.	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.
42	**Structure, authority and responsibilities**	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2	Driven from business strategy. KPI from business plan, quarterly business reviews. Driven from business strategy. KPI from BP, quarterly business reviews. Monthly reporting. BI Dashboard in flight. PDP and team goal setting. Business outside of operations require further work to link asset management with objectives.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.
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	A robust contractor management and consultancy process is in place, however it lacks some linkages back to AM policy and strategy for the engaged resources to understand plans.	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.	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.
48	**Training, awareness and competence**	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	AM training carried out as required. requirements are not documented. This is an area under review for improvement.	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.	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.
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	Our Learning Management System; AKO holds the required learning plans for roles. internal training modules and assessments are currently being developed/updated to cover these learning plans. Internal assessors are also being trained	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.	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.
50	**Training, awareness and competence**	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	Our Learning Management System; AKO holds the required learning plans for roles. internal training modules and assessments are currently being developed/updated to cover these learning plans. However, AM specific training and competency requirements are yet to be defined.	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.	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.
53	**Communication, participation and consultation**	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	Firstgas communication plans are primarily focused in external stakeholder. The need for better internal communications around the importance of Asset Management and the Asset Management systems is required.	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.	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.
59	**Asset Management System documentation**	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	The Firstgas AMP references the main elements of the asset management system.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.	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.

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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	Documents define the data required to be stored in Maximo, Meridian (the technical engineering document vault), GIS and Nucleus document control system as primary asset information systems. These systems contain data to be able to support asset life cycle.	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.	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.
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	Our assesment has highlighted that this area requires improvement. The current processes rely on individuals to manually manage data.	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.	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.
64	**Information management**	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Recent project to upgrade Maximo to the latest version engaged external consultants to review current operation, data structure and content. The project will refine current use to align with good industry practice and use of Maximo. Other information systems remain stable with regular vendor reviews.	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.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.
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. Risk management processes include enterprise risk, bowties and an assurance plan. As a requirement of AS2885 and the certificate of fitness, assets are risk assessed on a five yearly basis through a formal safety management study. New assets and modifications to assets are assessed for operational risk through a formalised HAZOP process. Individual risks are managed through a risk item register.	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.	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.
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 training needs are identified these are updated in the training matrix	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.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.
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	The pipeline management system manual is reviewed and updated each year to ensure changes to Acts, Regulations and Standards are incorporated into documents and communicated. Information disclosure requirements are reviewed as part of AMP and ID delivery process.	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	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.
88	**Life Cycle Activities**	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	Processes and procedures are in place to manage and control implementation of asset management plans. The Project management manual provides the process for design, modification, procurement, construction and commission of assets. Design standards manage the design and provide control with design, whilst asset maintenance standards provide management during its life cycle. These are controlled through review cycles established in the document control system.	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.	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.
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 a document management system to manage controlled documents. This includes processes for review and auditing of documents and processes by internal auditor to ensure that the processes are maintained.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.	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.

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Question No.	Function	Question	Score	Evidence—Summary	Why	Who	Record/documented Information	Assessed maturity level
95	**Performance and condition monitoring**	How does the organisation measure the performance and condition of its assets?	3	Performance and condition monitoring are communicated using a BI report with monthly reporting of metrics between senior and general management.	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).	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.
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	Documented processes are established for incident management, including internal or external audits, asset related failures or near misses and other incidents. Weekly meetings review each incident. Incident actions and closeouts progress are monitored monthly by senior management.	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.	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.
105	**Audit**	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Firstgas have an established audit procedure and assurance plan to ensure compliance against external and internal requirements. The AMS is periodically reviewed by an external provider, last completed in 2022.	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.	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.
109	**Corrective & Preventative action**	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Where poor performance or non conformance is identified, an investigator is assigned to 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 actions have been completed.	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	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.
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	Project performance metrics are continuously monitored, with an annual review undertaken to assess effectiveness and support ongoing improvement. The Risk item Register (RIR) is used to record poor performing assets and assess for remediation or replacement. Maintenance is reported monthly; faults and corrective maintenance are actively managed. Improvements are completed as part of incident investigation audits or added to the RIR for assessment and action.	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.	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.
115	**Continual Improvement**	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2	Regular attendance at industry conferences or workshops by employees across the business result in development of processes to align with current good practice. Improvements are assessed, scoped and estimated similar to project optioneering.	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.	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.

Schedule 14a – mandatory explanatory notes on forecast information

This Schedule requires GTBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

This Schedule is mandatory—GTBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

The difference between constant and nominal price capex in Schedule 11a is based on a forecast CPI of 2.2%.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Our approach for operational expenditure forecasts, as set out in Schedule 11b, is equivalent to the approach for capital expenditure, described above.

Appendix C. Asset Management Approach

This section outlines our structured and integrated approach to asset management, which is designed to achieve our organisational objectives, fulfil stakeholder expectations, and deliver value across the lifecycle of our assets. It reflects the key components of our asset management system (AMS), in alignment with ISO 55001.

Key elements of this include:

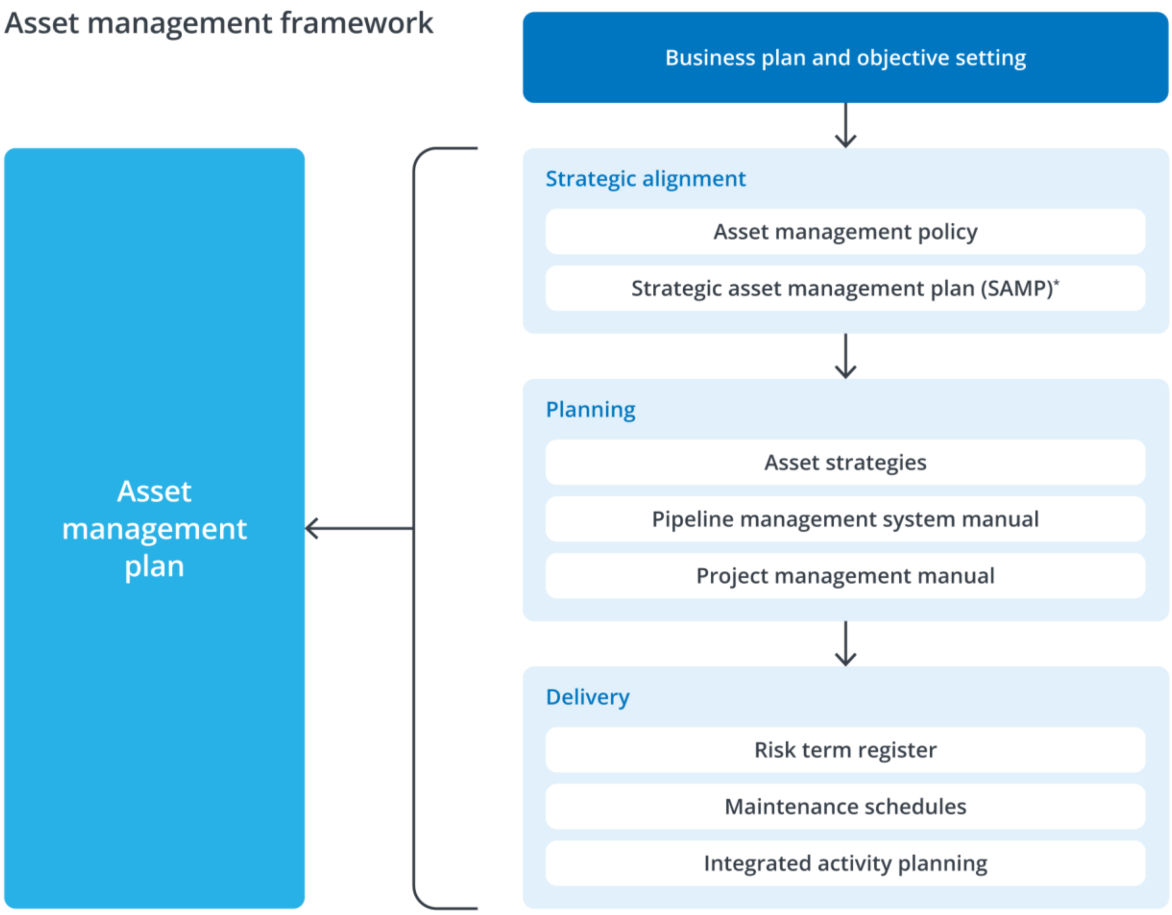
- **asset management framework:** establishes the structure and interaction of the asset management system components, ensuring alignment with organisational objectives and stakeholder requirements.
- **risk management:** embeds risk-based thinking into all asset-related decisions from network development planning, asset replacement through to operational decisions.
- **asset management support:** ensures adequate resources, competencies, and information systems are in place to support the asset management system.
- **performance measures:** establishes metrics to monitor and evaluate the effectiveness of the asset management system and its contribution to organisational objectives.
- **technical standards and legislation:** the technical and legal requirements governing our asset management.

C.1. Asset management framework

Our asset management framework (see Figure C.1) illustrates how we align our asset management activities with our organisational objectives and stakeholder expectations. It is a structured framework that connects our corporate objectives and stakeholder expectations with our asset management practices and defines our AMS.

Our asset management framework sets out principles and objectives that help us ensure our investments deliver safe, cost-effective services that meet the needs of our customers. It ensures that our decisions and activities are aligned, consistent, and capable of delivering value across the asset lifecycle. The framework is structured to align with ISO 55001:2024, ensuring a clear and consistent approach to delivering value from our assets.

Figure C.1: Asset management framework



**Strategic Asset Management Plan under development.*

Corporate strategy

We begin by understanding our organisational context and the needs and expectations of our stakeholders. This informs the scope of our AMS, which is designed to support the achievement of our organisational objectives.

Strategic alignment

Leading asset management standards (including ISO 55000) emphasise the importance of aligning an organisation's strategic plan with asset management objectives, asset management strategies, and asset management plans, right through to on-the-ground daily activities.

The concept of having clear 'line of sight' between stakeholder needs and daily activities is considered a key feature of effective asset management. This line of sight is illustrated in the key elements of our asset management system.

We are developing a strategic asset management plan (SAMP) and our asset management objectives are being updated based on the current uncertainties of reducing supply and demand of natural gas and our organisational plans and policies. These guide the development of our asset management plans for both gas transmission and distribution, ensuring that our activities are aligned with our long-term goals.

Planning

To implement our asset management plans effectively, we ensure that the necessary resources, competencies, and support systems are in place. We apply a structured decision-making framework that:

- defines the value we aim to derive from our assets.
- establishes criteria for asset-related decisions.
- considers risk, opportunity, and time horizons.
- supports governance and timely decision-making.

Delivery

Our delivery processes operationalise our strategy by translating our plans and objectives into lifecycle-based activities. They guide the planning, acquisition, operation, maintenance, and renewal of our gas transmission and distribution assets. Enablers include:

- clearly defined roles, responsibilities, and authorities.
- competency development and awareness programs.
- communication and information management systems.
- documented procedures and risk-based decision-making processes.
- integrated activity planning.

C.1.1. Asset management policy, strategy & objectives

These elements define our intent and direction for asset management. They ensure that our approach is aligned with our organisational objectives and that our asset management objectives reflect our commitment to safety, stakeholder needs, and effective risk management.

Asset management policy

Our asset management policy defines the overarching direction, principles, and commitments that guide how we manage our assets to deliver value and achieve our organisational objectives. It is a foundational element of our AMS and provides a basis for consistent decision-making across the asset lifecycle.

The policy is positioned within our asset management framework (see Figure C.1), linking our organisational context and stakeholder expectations to our strategic and operational asset management activities. It ensures alignment between our corporate objectives and the way we plan, operate, and improve our assets.

Specifically, the policy:

- **establishes a clear line of sight:** from stakeholder needs and organisational objectives through to asset-level implementation and performance evaluation.
- **provides a framework:** for setting asset management objectives and developing the samp and our annual amp.
- **commits to compliance:** with applicable legal, regulatory, and stakeholder requirements.
- **promotes continual improvement:** of our AMS and the performance of our assets.
- **supports integration:** with other business systems and functions, including risk, finance, and operations.

The principles outlined in the policy are embedded throughout our processes and systems, ensuring that asset management decisions are consistent, transparent, and aligned with our long-term goals. The policy is reviewed periodically and communicated across the organisation and to relevant stakeholders to maintain shared understanding and accountability.

Strategic asset management plan

Our SAMP is being updated in response to the evolving energy landscape and the uncertainty surrounding the future of gas in New Zealand. We are actively redefining our asset management strategy to ensure it remains robust, adaptive, and aligned with our organisational objectives and stakeholder expectations.

Our strategy is grounded in the principles of ISO 55001, particularly the emphasis on value realisation, risk-based decision-making, and continual improvement. It is also embedded within our asset management framework, ensuring a clear line of sight from strategic planning through to operational execution and performance evaluation.

To support this, we are developing future scenarios based on an asset becoming stranded in the following decades, 2040, 2050 and 2060. These models explore a range of credible pathways for the gas networks as we manage reducing gas supply and demand as New Zealand transitions to a net-zero carbon economy. These scenarios are not forecasts, but structured narratives that help us understand potential futures, identify key uncertainties, and define trigger points for action.

The outcomes of this scenario development will:

- inform a dynamic roadmap for our asset management planning
- support the alignment of our asset strategies with a ‘least regrets’ approach, prioritising flexibility and resilience while avoiding premature or irreversible decisions
- enable us to identify and monitor signals of change, ensuring timely and informed adjustments to our plans
- assessing long-term investment needs and implementing plans or considering substitution of short term solutions for risk mitigation and remediation.

This is not a one-off exercise. We recognise that our strategy must be continuously reviewed and refined as new information emerges, technologies evolve, and policy directions become clearer. This iterative approach ensures that our asset management remains responsive, future-focused, and capable of delivering long-term value to our stakeholders.

Asset management objectives

Our asset management objectives are aligned with our asset management policy and support the achievement of our organisational goals while addressing stakeholder needs and expectations. Each objective is monitored and reviewed regularly to ensure continued relevance and effectiveness. They are also embedded within our asset management framework, ensuring a clear line of sight from strategic intent to operational execution.

Our asset management objective area include:

- **safety:** prioritise the integrity of assets to ensure the safety of the people and places affected by operations
- **security and reliability**: provide a reliable, resilient and secure service that meets customer needs

- **environment**: preserve the environment by operating in a manner that mitigates environmental risks
- **compliance**: address and meet all legislative requirements
- **communication:** communicate The Company's investment plans to stakeholders, particularly the communities that host the assets
- **value**: operate in a manner that optimises the long-term financial outcomes for shareholders
- **decision-making:** balance the needs of competing objectives in a consistent and transparent manner.

Our SAMP will include an expanded suite of asset management objectives that guide our planning, decision-making, and performance evaluation.

C.1.2. Asset management plan

Our asset management plan (AMP) is a key document within our AMS that summarises how we manage our gas transmission assets to deliver value, meet stakeholder expectations, and comply with regulatory obligations. It provides a clear and structured overview of our asset management strategy, objectives, and practices, and serves as a communication tool for both internal and external stakeholders.

The AMP is developed in alignment with the Information Disclosure obligations under Part 4 of Commerce Act 1986. Specifically, the AMP:

- provides a 10-year forward-looking view of our asset lifecycle planning, including capital and operational expenditure forecasts, risk management strategies, and performance targets
- supports transparency and accountability by disclosing information required under Part 4 of the Commerce Act 1986, enabling stakeholders to assess whether our performance is consistent with that expected in a competitive market
- demonstrates how our asset management practices align with the principles of ISO 55001, including value realisation, risk-based decision-making, and continual improvement
- includes mandatory schedules and explanatory notes as required by Information Disclosure requirements, such as asset condition, forecast demand, and asset management maturity assessments.

The AMP is developed with oversight and input from our commercial and regulatory team, which ensures that the document meets all Information Disclosure and certification requirements. This team also supports alignment with our broader regulatory strategy and ensures that the AMP remains consistent with evolving regulatory expectations and industry best practice.

Key assumptions underpinning the AMP

This AMP is based on a set of foundational assumptions that reflect our understanding of the current and future operating environment. These assumptions underpin our long-term planning and investment decisions and are consistent with the strategic direction.

The key assumptions are:

- **gas transmission role and industry structure:** the gas transmission network will continue to play a critical role in New Zealand's energy system during the planning period. We assume that the current industry structure will remain broadly stable, with gas continuing to flow from the Taranaki region to customers across the North Island

- **service delivery model:** works will continue to be delivered through a mix of insourced and outsourced activities. Outsourcing decisions will be based on capability, cost-effectiveness, and resource availability, ensuring resilience and flexibility in delivery
- **service provider availability:** we assume no major disruptions to the availability of key service providers, including contractors and suppliers critical to the delivery of maintenance and capital works.
- **demand and customer expectations:** while we aim to support continued use of the gas transmission network, our demand forecasts are based on prudent assumptions that reflect depleting gas reserves, historical trends and current policy settings. We assume that customer expectations around safety, reliability, and environmental performance will continue to evolve gradually.
- **regulatory stability:** we assume that the regulatory framework that governs reliability and allowable expenditure will remain broadly stable.
- **asset performance and condition:** our assumptions about asset condition, performance, and remaining life are based on current inspection data, historical performance, and engineering judgement. For this AMP we have reviewed our asset condition scoring to ensure these fully reflect latest information, this has led to updated values compared with our 2024 AMP Update. These assumptions are reviewed regularly and updated as new information becomes available.

Where possible, these assumptions have been quantified and referenced in the relevant sections of this AMP. Assumptions based on third-party information are clearly cited. We recognise that these assumptions may evolve, and we will review and update them as part of our regular AMP review cycles.

AMP approval process

Once the AMP and associated forecasts have been prepared, reviewed and challenged by our management team, it is then reviewed by the audit, risk, and regulation committee (a Board subcommittee). When feedback has been incorporated, the AMP is then submitted for formal certification, by two directors, prior to publication.

C.1.3. Performance evaluation and improvement

We continuously monitor and evaluate the performance of our assets, asset management activities, and the AMS itself. This includes:

- regular performance measurement and analysis
- internal audits and management reviews
- corrective and preventive actions
- proactive interventions actions to address future needs and opportunities.

This cycle of evaluation and improvement ensures that our asset management practices remain effective, efficient, and aligned with our evolving context and stakeholder expectations.

C.2. Risk management

This section outlines our approach to identifying, assessing, and managing risks across the network. It includes our methods for classifying risks and implementing appropriate mitigation actions, ensuring that risk-based thinking is embedded throughout our decision-making processes.

Clarus applies a comprehensive and integrated approach to risk management, aligned with ISO 31000:2018, to ensure that risks are identified, assessed, and managed consistently across all business units. This section outlines the governance structure, methodology, and operational practices that underpin risk management across the organisation, with a focus on the gas transmission business.

C.2.1. Risk management framework

The Clarus risk management framework is designed to support strategic and operational decision-making by embedding risk awareness into all levels of the business. It is governed by the risk management policy and coordinated through the risk management manual. The framework includes:

- a standardised methodology for risk assessment and treatment
- defined roles and responsibilities for governance and execution
- integration with asset management and business planning processes
- alignment with regulatory and industry standards (e.g. AS/NZS 4645, AS(/NZS) 2885, NZS 7901).

C.2.2. Risk management process

The risk management process follows a structured lifecycle:

- **context setting:** define objectives, scope, and influencing factors
- **risk identification:** use workshops, audits, and incident reviews to identify threats and opportunities
- **risk analysis:** assess likelihood and consequence using standard matrices
- **risk evaluation:** determine escalation and treatment needs based on severity
- **risk treatment:** develop specific, measurable, achievable, realistic and time-bound mitigation plans and assign owners.

C.2.3. Enterprise risk calibration

To ensure comparability across business units, risks are calibrated against a corporate risk matrix. This allows for consistent prioritisation and reporting to the Executive and Board. Calibration is overseen by the Manager Risk and Assurance and the risk governance committee chair.

C.2.4. Critical barriers and bow tie analysis

For its top enterprise risks, Clarus applies bow tie analysis to visualise threats, controls, and consequences. Critical barriers, which are essential to preventing or mitigating top events, are identified and managed with defined performance standards and testing protocols.

C.2.5. Reporting and continuous improvement

Risk reporting at Clarus is coordinated through the risk governance committee, with risk-type owners submitting updates when requested. These reports are proportionate to the severity of the risk and include details such as risk context, control status, mitigation progress, emerging trends, and overall management status.

The risk management framework is subject to formal review on an annual basis. This review incorporates lessons learned from incidents, feedback from risk owners and treatment owners, and findings from operational assurance and internal audit. The objective is to ensure continuous improvement and alignment with Clarus' strategic goals and regulatory obligations.

Each business unit maintains a risk management plan that consolidates treatment plans for critical risks. These plans include the rationale for selected treatments, assigned responsibilities, performance measures, resource requirements, and monitoring protocols to ensure risks are managed to as low as reasonably practicable (ALARP) or so far as reasonably practicable (SFAIRP) standards.

C.2.6. Emergency and contingency planning

Asset risk management is a core component of our overall risk management framework, with a focus on managing asset-related risk, particularly safety.

Our embedded emergency management framework is based on the coordinated incident management system, commonly referred to as CIMS. Staff performing any function within the CIMS structure are trained and regularly tested with emergency exercises. We maintain emergency response and contingency plans to ensure the safe and reliable operation of the gas transmission system during abnormal conditions. These plans are designed to manage emergencies such as major pipeline failures, natural disasters, or other events that could disrupt service.

The emergency response framework includes:

- **emergency response plan**: this outlines procedures for training, responding to incidents, roles and responsibilities, communication protocols, and coordination with external agencies.
- **critical spares management**: we maintain an inventory of critical spares to enable rapid restoration of service following equipment failure or damage.
- **contingency planning**: the transmission network is designed with redundancy and flexibility, including alternative control options and bypass arrangements to maintain supply during outages.
- **civil defence and emergency management coordination**: as a lifeline utility under the Civil Defence and Emergency Act 2002, we participate in regional emergency planning and exercises to ensure preparedness and alignment with national resilience strategies.
- **annual exercises and reviews**: emergency procedures are tested through regular exercises and reviewed to incorporate lessons learned and improve response capabilities.

C.3. Asset management enablers

Our asset management is supported by a suite of enablers that ensure decisions are informed, consistent, and aligned with strategic objectives. These elements provide the necessary oversight, governance, and operational resource to support the development and execution of asset management activities. They also help ensure that resources are appropriately allocated.

These include the systems, processes, and governance mechanisms that support and regulate all other elements of the AMS. They ensure that our asset management activities are consistent, auditable, and continuously improving.

C.3.1. Asset management capability

This section discusses our approach to ensuring appropriate levels of asset management competency.

Asset management maturity assessment

We have undertaken an internal asset management maturity assessment for our gas transmission and distribution businesses. This assessment, conducted in May 2025, was aligned with the ISO 55001 standard and the Commerce Commission's (asset management maturity assessment tool) AMMAT disclosure requirements.

This marks a shift from previous assessments, which were based on the PAS 55 standard and a 0 to 4 scale. The latest assessment adopted the Institute of Asset Management's 0 to 5 maturity scale, which provides a more granular and internationally aligned assessment framework. Under this scale:

- scores of 0 to 2 reflect increasing levels of awareness and development
- a score of 3 represents "competent", indicating systematic and consistent achievement of ISO 55001 requirements
- scores of 4 and 5 represent "optimising" and "excellent" maturity, respectively.

The objectives of the assessment were to benchmark the current state of asset management maturity against ISO 55001 and to identify improvement opportunities and develop a roadmap to achieve full alignment with the standard.

> **AMMAT score**
>
> Our asset management maturity assessment produced an overall AMMAT score of 2.6.
>
> Further details on the basis for this result can be found in Schedule 13, included in Appendix B.

The assessment covered all clauses of ISO 55001 and produced an overall maturity score of 2.6, placing us in the "developing" category. This indicates that credible and resourced plans are in place, but further progress would be required to achieve consistent and systematic compliance. To support transparency and prioritisation of improvement actions, the assessment also evaluated the accuracy of maturity scores across key focus areas. The accuracy scale used was:

- **High**: comprehensive, consistent data and robust evidence available.
- **Medium**: partial or inconsistent data available; further validation may be needed.
- **Low**: limited data available, or information is based on assumptions; significant gaps or discrepancies exist.

The main observations are set out in the following tables.

Table C.1: Areas of greater maturity

Strength Area	Details	Score
Operational execution	Reliable lifecycle delivery and change control	3.1
Support functions - communication and documented information	Strong documentation and communication processes supported by the Nucleus document management system	3.0

Table C.2: Areas of improvement

Improvement Area	Reason	Score
Organisational context and planning	SAMP still being finalised	2.4
Knowledge management	Gaps in formal processes for acquiring and managing knowledge	2.7
Performance evaluation	Formal management review processes are not yet fully established	2.7

Table C.3: Improvement actions

IMPROVEMENT ACTIONS FOR 2026
Finalise and implement the SAMP
Develop a competence matrix and training programme for asset planners and middle managers
Establish formal management review processes
Improve data quality and scoring accuracy through enhanced evidence retention and validation
Ensure readiness for ISO 55001 certification by the end of calendar year 2025

The outcome of the assessment has informed our AMMAT disclosure in Appendix B.

Figure C.2: ISO 55001 asset management maturity

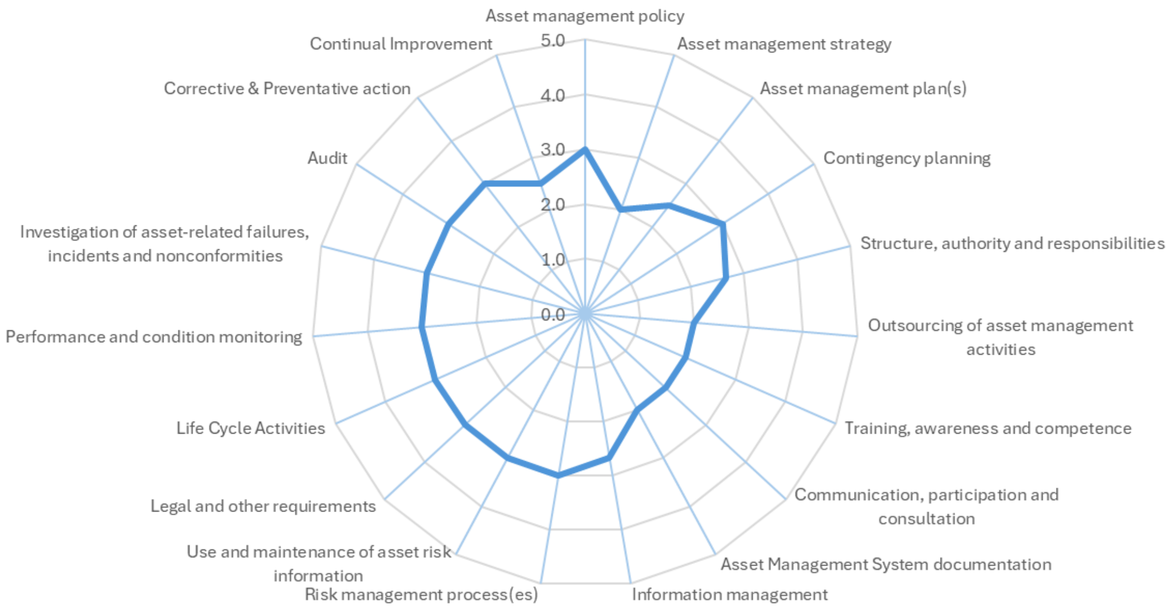


Table C.4: ISO 55001 asset management maturity

FOCUS AREA	ISO 55001 CLAUSE	SCORE (CLAUSE)	SCORE (AREA)	LEVEL OF EVIDENCE
Leadership and strategic direction Commitment, policy, roles	5.1	2.6	2.8	Medium
	5.2	3.2		
	5.3	2.6		
Organisational context and planning Understanding context, stakeholder needs, scope, SAMP, objectives, risk & opportunity management	4.1	2.3	2.4	Medium
	4.2	2.6		
	4.3	2.0		
	4.4	2.0		
	4.5	2.3		
	6.1	3.2		
	6.2	2.0		
	6.3	2.7		

Focus area	ISO 55001 clause	Score (clause)	Score (area)	Level of evidence
Support Functions – Part 1 Resources, competence, awareness	7.1	2.3	2.2	Low
	7.2	2.3		
	7.3	2.0		
Support Functions – Part 2 Documented information, communication	7.4	3.2	3.0	High
	7.5	2.9		
Support Functions – Part 3 Data and information, knowledge management	7.6	3.2	2.7	Medium
	7.7	2.1		
Operational execution Lifecycle delivery, outsourcing, control of change	8.1	3.3	3.1	High
	8.2	2.9		
	8.3	3.0		
Performance evaluation and improvement Monitoring, internal audit, management review, corrective & predictive actions	9.1	2.8	2.7	Medium
	9.2	2.4		
	9.3	2.0		
	10.1	3.0		
	10.2	3.0		
	10.3	3.0		

Asset management improvement plan

Following our recent internal asset management maturity assessment, we identified several areas where understanding of individual and team roles within the asset management system could be improved. Engineering and operations personnel demonstrated greater familiarity with their responsibilities. This gap highlighted the need to strengthen awareness and competence across all roles.

To address this, we have included a targeted action within our improvement plan to provide a tailored mix of formal and informal training focused on asset management-related roles. This approach aims to enhance understanding of the asset management system and overall competency, ensuring that every team member, regardless of role, can contribute effectively to our asset management objectives.

To further improve our asset management system, a priority activity is finalising critical asset management documentation, including a SAMP and associated frameworks. Completing these elements is essential to ensure that the various business units are coordinated and consistent in their approach to asset management.

Another key improvement area is the review and update of our service levels. The existing transmission environment has changed significantly since these service levels were originally developed. As a result, it is necessary to develop new service level frameworks that reflect current and potential future operational conditions and ensure the network is managed in alignment with today's requirements.

The table below outlines our improvement plan.

Firstgas

Table C.5: Asset management improvement areas

Improvement area	Action
Asset management system	Finalise strategic asset management plan (SAMP) Establish asset management objectives Define asset management decision-making processes Develop asset management system scope and process document to integrate
Levels of service	Levels of service (KPIs) require development and promotion to the wider business Report on asset KPIs (e.g., critical contingency thresholds, compressor availability), with initial metrics Asset management system management review
Awareness	Awareness of the asset management system needs to be improved AKO Module - review onboarding requirements
Competence	Implement an asset management-specific training plan for specific roles in the organisation (e.g., asset management fundamentals)
Benchmark	Review performance against 2023 benchmark and external reviews Review and understand trends and changes between assessments.

Competency and training

Effective competency and training help ensure staff and external parties performing design, construction, operations or maintenance activities meet specified competency requirements. All personnel conducting these activities on the transmission network must meet competency requirements as specified by the training matrix.

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

C.3.2. Asset management governance

Effective expenditure governance provides the basis for investing at prudent and efficient levels to achieve our asset management objectives.

Governance

Asset management plans (AMPs), strategic asset management plan (SAMP), objectives, and decision-making criteria are reviewed by the operation's senior leadership team. After their input, proposed changes are submitted to the executive team for approval.

The audit, risk, and regulation committee is responsible for challenging and approving the asset management plans and the 10-year forecasts, ensuring alignment with the business objectives.

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, prioritise, plan, budget, execute, control, and closeout capex projects and major opex. Key objectives include the following.

- evaluate capex projects and major opex according to the business plan, strategic planning, and asset management policy.

- ensure appropriate analysis has been conducted (e.g., lease versus buy, outsource versus in-house).
- leverage best practices used by us and the gas sector.
- evaluate the impact of not doing the capital or maintenance project.
- compare alternatives to determine the best solution (e.g. replacing vs repairing equipment, deferral).
- 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.

Investment principles

In addition to the expenditure guidelines, we use a set of investment principles to help inform the trade-offs associated with our expenditure decisions, these include the following.

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

Financial authority

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

Table C.6: Delegated financial authority levels

GOVERNANCE LEVEL	AUTHORITY – CAPEX ($000)	AUTHORITY – OPEX ($000)
Chief executive officer	2,000	Budget

Governance level	Authority – capex ($000)	Authority – opex ($000)
Chief operating officer	1,500	1,500
Chief technology and improvement officer	1,000	1,000
Business unit managers	250	250

Challenge processes

The material included within the AMP reflects the network development plans, lifecycle delivery plans, customer connections forecast, and 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 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.

C.3.3. Business support

Our people play a central role in managing our assets. Ensuring enough people with the right competencies is essential to achieve asset management objectives. Our asset management is supported by a range of enabling functions, systems, and capabilities that ensure the effective and efficient delivery of asset-related activities.

To support asset management teams, several corporate functions provide services that are integral to support asset management functions. These include customer management, finance, and information communication technology (ICT). These functions either directly or indirectly support the transmission side of the business as described in the examples below.

- **Commercial and regulatory:** supports strategic, commercial, and regulatory outcomes through strong customer relationships and industry engagement.
- **Finance**: manages financial operations, valuation, compliance, and systems to support performance and decision-making
- **Health and safety**: provides health and safety leadership, enabling safe, efficient, and high-quality work.
- **Legal, governance and risk**: provide pragmatic legal and governance advice, monitor and manage assurance plans, support directors to ensure our statutory obligations are met.
- **Marketing and communications**: shape brand and reputation through stakeholder engagement and communications support.
- **People and culture**: attract and retain capable people through managing HR, payroll, and internal communications to build a strong, inclusive workplace.
- **Technology and improvement**: responsible for ICT strategy, delivery, and operations to enable our business to meet strategic goals and maintain operational security using digital technologies.

These support elements are essential to the day-to-day operation of the AMS and contribute to the achievement of our strategic and operational objectives.

Business support allocation methodology

The allocation of business support costs to the transmission and distribution businesses is based on a combination of the following factors.

- The first is applied to expenditure that has a relationship with the assets (such as ICT systems) and is an allocation on a proportion of regulated asset base value.
- The second is related more to supporting the people in the business (such as-building costs) and is proportioned based on the relative headcount working in each business.
- The third allocation applies to certain legal, consulting, or one-off spend where allocation is specifically determined based on an estimate of the time spent.

C.3.4. Information communication technology (ICT)

Information communication technology (ICT) enables us to meet strategic objectives of the AMS through business-optimised technology solutions. Our technology teams support, maintain, and improve the technology infrastructure, communications, systems, cyber security, data, and operational intelligence that enable our day-to-day business activities.

Technology is a key enabler for the AMS, providing data and tools to make informed decisions and to run the network safely, securely, and efficiently.

As the pace of technological change accelerates, long-term planning inevitably faces greater uncertainty. In response, the team’s supporting ICT are actively delivering a range of strategic initiatives aimed at building our digital technology foundation through strengthening our cyber security posture, establishing foundational data platform capabilities, developing specialised business intelligence, and investing in our asset management system which is currently being re-implemented with a modern commercial off-the-shelf (COTS) solution.

This strategic effort continues to apply our ‘cloud-first’ architecture principle to our technology systems. The shift to subscription based, virtualised and cloud-based services has prompted a reallocation of ICT expenditures, moving from capex investments to primarily Opex. Over the next five years we will progress the cloud transition across the majority of our on-premises and data centre hosted technology systems. This will require an initial step change increase in Opex and is expected to stabilise licensing and maintenance costs, while also enabling the standardisation of system configuration and data structures, resulting in best practice commercial terms and support models.

In parallel, cyber security has led to a significant and reoccurring rise in Opex as a step change, split between network and non-network technologies, with added costs for ongoing improvement projects for identity management and monitoring tools. Baseline Opex include software subscriptions, security operations roles, and secure network maintenance. This expenditure is necessary to maintain cyber defences, minimise service disruption risks, and enhance protection measures.

Solutions overview

To support business alignment and cost optimisation, our technology solutions are classified into three asset groups.

- **Business unit:** provide a tailored solution to meet specific operational needs of a single business unit, in alignment with enterprise architecture guidelines.
- **Shared business:** provide a solution or capability supporting the needs of multiple business units or functional areas as a unified platform to effectively manage areas of operation.

- **Core technology:** provide foundational technology platforms and services that underpin the entire enterprise technology environment, which are standardised, scalable, and centrally governed to ensure resilience, interoperability, and cyber security.

Figure C.3: Firstgas transmission technology solution classification

Technology strategy

We are redefining the function of technology from a supportive element to a strategic driver of our business' future focused on strengthening our digital foundations and enabling smarter ways of working. We're shifting to be a digital business through modernising core platforms, embedding cloud-first architecture, and improving cyber security to address key risks and threats and data intelligence capabilities. Through digitising processes and simplifying tools, we support business agility, operational efficiency, and better customer outcomes.

Our technology strategy aims to shape a smarter energy future through five strategic priorities, as set out in the following table.

Table C.7: Technology strategic priorities

Strategic priority	Description
Build our digital foundation	Establish a strong, scalable digital core to enable agility and growth. This priority focuses on simplifying and standardising technology platforms, leveraging cloud-first infrastructure, and fully utilising core systems to boost performance and business agility.
Embrace a culture of cyber confidence	Integrate cyber security into everything, fostering confidence and resilience. Aiming to embed robust cyber security practices into its DNA, meaning every employee and process plays a part in security.
Unlock the power of data for our people	Turn data into a strategic asset that empowers employees. This involves making data visible, accessible, and actionable in daily work.
Raise our operating grade	Elevate internal processes and skills to achieve operational excellence. Streamline and standardise with best-practice frameworks, invest in upskilling people, and implement metrics to track performance.
Enable the future	Harness emerging technologies and innovation to transform the ways we work and open new opportunities for our customers. This priority is about looking ahead and embracing game-changing technology such as artificial intelligence (AI) and automation, building on our cloud foundations.

Business unit solutions

The business unit solution classification represents technologies which monitor and control network equipment, dispatching instructions to field technicians, demand scheduling, pipeline balancing, simultaneous operations, control and approve site activity, incident management, and operational intelligence which focuses on real-time performance monitoring and trigger alerting.

We have nearly completed our multi-year SCADA upgrade programme to improve the reliability, security, and integrations with our asset management platform. Ongoing improvements are expected to continue as we target areas of the pipeline to improve monitoring.

In FY26 we will kick-off planning for a multi-year programme of work replatforming our open access transmission information system (OATIS) and balancing gas information exchange (BGIX) systems as part of lifecycle critical maintenance. This programme addresses legacy technologies and aims to transition OATIS to a cloud-native architecture, ensuring long-term support and security. This requires both capital and operational expenditure in both network and non-network areas. For a description of our business unit solutions, refer to Table C.8.

Table C.8: Firstgas business unit solutions

Solution	Description	Improvement programme
System operations	Our SCADA system is a mission critical platform used to remotely monitor and control the gas transmission network in real time. It collects data from field devices such as RTUs, programmable logic controllers and sensors. Incident management system: reported faults are recorded in a custom Azure web platform and managed via the enterprise asset management system through a combination of event management, service requests and work orders.	The SCADA programme, which is replacing the legacy SCADA is nearing completion. The upgrade of the master terminal system will improve reliability, and security over FY25-FY26. Continuous improvements are expected to improve operational decisions such as integrating with our asset management platform to support real-time network control. Additional investigation is required to improve incident management once the new asset management solution is implemented.

Solution	Description	Improvement programme
Transmission operations	OATIS, BGIX and D+1 form the core transmission operations platform, managing nominations, allocations, pipeline balancing, and commercial transactions, with D+1 supporting daily cost allocation across pipeline users.	Planning and cost estimates for operations management systems application modernisation and cloud transition is to be completed in FY26. The re-platforming implementation is expected to take place FY27-FY28. Dependent on industry guidance we have noted the potential for D+1 to move to 7-day processing and regulated commercial price model changes. Both will require funding to implement.
Meter reading and validation	The metering validation system received information from meters, gas chromatography machines, and flow computers to provide accurate gas quantity reporting by validating field data and integrating outputs into transmission operations (OATIS) platforms.	System life cycle and commercial optimisation review proposed for FY28.
Radio communications network	Our radio communications network connects our control room and field technicians on a secure network across the gas transmission and distribution network.	The radio network infrastructure is nearing end-of-life and will need to be replaced. In FY26 a network strategy will be created to support the replacement project decisions in FY26-FY28. There are several legacy communication systems on the network are in various stages of being decommissioned including VPN network, copper phone lines, and 2G/3G cellular networks.
Pipeline management system	The pipeline management system delivered via a COTS platform, is a cloud-based SaaS solution that supports Firstgas in maintaining pipeline safety and compliance. It provides structured scheduling of maintenance and monitoring activities, risk identification and control tracking, and ensures alignment with standards.	No planned improvements.
Land and planning management	Our land & planning solution manages landowner information and easement permit data, support pipeline location responses, and integrates field data from UAs and permits.	Users of the system are currently reviewing the functionality and data quality. More investigation is required before determining the replacement or cloud transition approach which is expected to be defined in FY27.
Operational intelligence	Our historian is used as an on-premises operational technology platform to capture and store time-series data from SCADA and other control systems. It supports real-time and historical signal analysis, enabling predictive maintenance, and performance monitoring.	The historian platform operational intelligence will integrate SCADA data into the corporate network to enable real-time and historical signal analysis, predictive maintenance, and enhanced reporting across systems like Maximo and Microsoft fabric platform. This is expected to be implemented in FY27-FY28.

Shared business solutions

Our shared business solutions provide unified platforms to support multiple business units or function areas to drive cost efficiency, consistency, and collaboration across the organisation while reducing duplications. We are running two multi-year strategic programmes of work as follows.

- **Operational technology cyber security programme:** is positioned to increase our cyber security posture across our operational technology network. Ongoing investment is essential to effectively manage our assets and cyber security risks through improved monitoring and detection. This requires capex and opex in network and non-network areas.

– **Enterprise asset management programme:** is a multi-year enterprise asset management programme, investing in technology and business capabilities to fully digitise asset management and boost efficiency over the next 25 years amid a complex energy landscape. By simplifying and improving asset data structures, we will enhance our ability to use asset condition and inspection results remotely, reducing health and safety risks and enabling smarter, risk-based investment decisions. This requires capex and opex in network and non-network areas.

For a description of our shared business solutions, refer to Table C.9.

Table C.9: Firstgas shared business solutions

SOLUTION	DESCRIPTION	IMPROVEMENT PROGRAMME
Operational technology cyber security management	Establish and develop comprehensive operational technology cyber security resilience through secure physical and network architectures, implementation of preventative measures, detection and response capabilities, and improvements to our operational security management capabilities.	An ongoing operational technology cyber security programme will continue post-SCADA implementation in FY27-FY35. Ongoing investment is essential to effectively manage our assets and cyber security risks through improved monitoring and detection. This requires both capex and opex in network and non-network areas.
Financial management	Our finance and operations solution supports corporate finance and supply chain management and enables budgeting, forecasting, procurement, billing, and financial reporting. It is integrated with systems such as our asset management solution and data platforms.	Subject to regular health checks, license optimisation, and maturity assessments to ensure performance and cost-efficiency.
Health & safety management	Incidents related to network assets and customer complaints (non-staff related) are recorded, managed, and reported via the Maximo enterprise asset management system. Workplace related incidents and injuries are managed via manual processes and registers.	Planning to complete a health & safety capability map in FY26 to enable the assessment of suitable tooling for recording, managing, and reporting workplace related incidents and injuries.
Enterprise asset management	Our asset management platform supports lifecycle asset planning, maintenance execution, and service delivery. The tooling is integrated with GIS, corporate financials, and our data platform.	We are currently re-implementing our enterprise asset management solution, correcting legacy data structure issues and configuration conflicts to be complete in FY25-FY26. The new solution enables accurate data capture at source, integrates with field mobility tools to improve operational efficiency, regulatory compliance, and decision-making. Once the new cloud-based system is embedded we will continue to invest in the platform to gain better insights about our assets and streamline management process through introducing mobile field applications, process automation, predictive analytics, and leverage AI capabilities to support remote data-driven decisions over FY26-FY29.
Geographic information system (GIS)	GIS is the master spatial register for pipeline assets across the Firstgas networks. It integrates geospatial, technical, connectivity, and land management and asset data which cross references with the enterprise asset management solution.	Server upgrades and additional storage for LiDAR and imagery (UAV and manned aircraft) planned for FY26 and is expected to grow. This will enable desktop analysis reducing the need for site visits which will lower operating costs and minimise health and safety risk.

Solution	Description	Improvement Programme
	There is also growing need to meet compliance obligation inspecting assets via mobile applications which would be done in conjunction with our enterprise asset management solution.	We are currently implementing the utility network framework over FY25-FY26, which will enable rule-based connectivity and attribute modelling improving data integrity. We are also migrating and updating our GIS SQL servers in our data centre. Upgrading our application development toolset in RY26 as an application lifecycle maintenance and improved user experience. Ongoing planning for a cloud transition will progress FY27-FY29.
Payroll services	Our payroll processing system is a standalone modern cloud system and used to manage employee remuneration.	Integration between our payroll system and active directory is planned for FY26 to reduce manual keying errors and introduce user provisioning time savings.
Web content management	Our cloud-based web content management system (CMS) is used across Firstgas. It supports consistent branding, streamlined content updates, and integration with features such as GIS mapping, outage notifications, recruitment interfaces, and "Get Connected" services.	No planned improvements.
Project management	Our central project planning and scheduling tool is used to manage engineering and capital projects. It supports lifecycle tracking, resource allocation, and integrated activity planning across project phases.	System upgrade planned for FY26 due to end-of-life integration limitations. Further investigation to be completed in FY27-FY28 to determine if alternative tooling is required to improve project planning and resource management.
Engineering tools and management	There is a suite of engineering management systems to support asset design and modelling. Drafting design drawings, schematics, and layouts. Simulation tools to enable analysis of network performance, operational scenarios, and system optimisation.	No planned improvements.
Engineering document management	Our engineering document management system (EDMS), used to store and manage asset-related documentation including AutoCAD drawings, engineering plans, work orders, and equipment records.	No planned improvements.
Recruitment management	Recruitment and onboarding tooling to support the end-to-end hiring processes, including job posting, candidate tracking, and onboarding.	No planned improvements.
Contract management	Our enterprise contract management system and digital signing platform is used to manage contracts, confidentiality agreements, and governance records.	Lifecycle review scheduled for FY27.
Employee engagement	The employee engagement system is used to run structured campaigns on topics such as health and safety, technology adoption, risk awareness, and organisational culture.	Lifecycle review scheduled for FY27.
Learning management	The enterprise learning management system (LMS), used to deliver, track, and manage employee training and development. It supports compliance-	No planned improvements.

Solution	Description	Improvement Programme
	based learning, onboarding, and professional development.	

Core technology solutions

Our core technologies provide foundational platforms and services that underpin our entire environment including the infrastructure that hosts operational technology. We have two multi-year strategic programmes of work, as follows.

- **Cyber security programme:** Designed to continuously improve our corporate network cyber security posture moving towards zero trust model while prioritising and addressing vulnerabilities and improving controls. This will protect our asset investments and provide assurances that we are effectively managing our cyber security risks. This improvement requires non-network capex and opex.
- **Data programme:** A multi-year programme focused on unlocking data for our people by developing core business data products on our modern data platform to enable business and operational intelligence, data driven decisions, and identify opportunities. The improved data analysis means we can optimise our investments and allocate our expenditure more effectively and efficiently. This requires primarily opex in non-network areas.

For a description of core technology solutions, refer to Table C.10.

Table C.10: Firstgas core technology solutions

Solution	Description	Improvement Programme
Cyber security management	Firstgas' cyber security approach and activities are structured to align with the National Institute of Standards and Technology cyber security 2.0 framework. It spans core network systems, supporting platforms, and cloud services, with structured controls for identity management, access permissions, vulnerability detection, and incident response.	The cyber security programme planned over FY26-FY35 will focus on incremental improvements towards zero trust model. We are also prioritise addressing vulnerabilities and improving controls based on cyber security risk assessments. Exploring options for information management and data classifications to keep our information secure.
Data and voice comms	The wide area network services are provided with the corporate internet breakout via our primary data centre. Voice communications are managed via a session initiation protocol truck, including direct dial-in, into the primary data centre and delivered to users via Microsoft Teams. This includes an interactive voice response service for the control room.	We are and will continue to complete lifecycle reviews, improve, and replace data connectivity and communications.
Data platform management	We are operating both our legacy on premise enterprise data warehouses and modern data platform. Our modern data platform is a cloud native scalable, integrated platform that collects, stores, processes, analyses, and governs data efficiently. It will enable the ability to support real-time insights, AI, and advanced analytics. We have designed a comprehensive data governance framework, completed a modern data platform proof of value, and began a multi-year data programme to implement our modern data platform, replacing the legacy enterprise data warehouses with a cloud native solution.	The process to ingest, transform, and promote data products for improved business insights with our data governance framework will continue to progress FY26-FY29. Investment in data quality, governance, and democratisation is a strategic factor required for the efficient and effective management of the AMP.

Solution	Description	Improvement Programme
Integration management	Our centralised integration system streamlines data flow between applications for consistent observability, monitoring, and alerting.	System improvements requiring integration will use our centralised integration tool in alignment with our architecture principles.
Productivity suite	A collection of software tools designed to help individuals and teams perform common work tasks more efficiently. Intranet used to securely share information, resources, and tools among our employees. Microsoft 365 productivity suite to support document creation, communication, file storage, task management, and workflow automation. Business process management software to support mapping, managing, and improving internal processes.	We are currently considering moving away from our business process management system in FY26, considering cost vs. business value.
Business intelligence	The business intelligence platform bring data to life with interactive dashboard reporting.	A data governance framework and data & analytics community of practice have been established as part of a broader strategy to enhance data literacy and accuracy. The implementation of a modern data platform and governance structure is intended to increase the reliability of reporting, support changes in governance practices, and facilitate the curation and delivery of data for decision making through automated reports, self-service reporting, and AI-driven analytics over FY26-FY29.
IT service desk	Our central support platform that manages and resolves IT issues, service requests, and user onboarding through a ticketing system.	Our current IT service desk tooling is an ageing on premise solution due for a lifecycle replacement. We will be exploring cloud-hosted solutions that enable self-service and generative AI connectors.
Information management	Information management supports the ability to store, access, and protect critical documents and data. With the introduction of AI tools, we require the need to invest in our information management governance.	Over FY26-FY27 we will consider document storage options, additional information governance controls, and cyber security to protect against unauthorised access. This will allow us to be more confident in our generative AI interactions and have privacy assurances for interacting with sensitive information.
Artificial intelligence	We are integrating AI into our enterprise ecosystem through embedded systems, advanced analytics, and standalone tooling.	We are rolling out generative AI capabilities across our organisation. In the future we will leverage the information products in our modern data platform to apply advanced modelling and AI tools that will improve insights and decision-making across our assets.

Minor fixed assets

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

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

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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.

C.3.5. Other non-network assets

Other non-network assets are those assets that are not directly part of the core gas transmission network.

Plant tools and equipment

We maintain, operate and renew plant, equipment and tools essential for the operation and maintenance of the gas transmission network. This includes a diverse range of test equipment for the certification of metering systems, as well as specialised devices for pipeline location, welding, hot tapping, and stoppling. In FY26 we will replace our radio transmitter hardware in our vehicles as the current hardware and system is coming to end-of-life and more flexible lease solutions are available, we also plan to replace our hot tapping equipment.

Offices and facilities

We maintain a mix of owned and leased facilities, including office buildings and storage sites. Our main offices are in Hamilton and Wellington, while our head office in New Plymouth is company-owned.

Our facilities management programme aims to ensure that our offices and stores are safe and secure for our employees and contractors, functional and fit for purpose, support improved productivity and efficiency, and are cost effective to procure and operate. These facilities must also be appropriately sized to support future staff growth and materials storage requirements.

Our facilities management ensures buildings remain effective and productive through regular maintenance, upgrades, and compliance with safety standards, supporting operational needs and adapting to workplace changes.

Vehicles

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

Renewals

The forecast for other non-network capital expenditure is expected to remain relatively stable with ongoing expenditure to manage lifecycle replacements of vehicles, tools and equipment and property.

Table C.11: Main planned other non-network expenditure forecasts

KEY AMP 25 NON-NETWORK PROJECTS	AMP 25 FORECAST (000)
Motor vehicle renewals	9,539
Radio transmitter renewals	768
Instrumentation test equipment renewals	950
Pipeline hot tapping equipment renewals	740

A significant change from AMP 2023 is the removal of forecast expenditure for rebuilding the existing office in New Plymouth. Instead, the approach has shifted to ongoing maintenance and retrofitting of the current facility, ensuring its continued functionality without the need for major redevelopment.

C.4. Performance measures

Our performance measures reflect operational, equipment reliability and other compliance measures. A key premise for our AMP-related planning is that existing reliability and supply quality levels will be maintained. Accordingly, these targets are presently set at a constant value for the current AMP planning period. Performance against these targets is also discussed.

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

C.4.1. Security and reliability

Below we discuss performance against our security and reliability measures.

Response time to emergencies

We take the safety of the public and its workforce very seriously and aim to attend to emergencies occurring on our transmission system as soon as practical to prevent any damage or harm to the public, employees, contractors and neighbouring properties.

Our current target is to attend all emergency events within 180 minutes.

Table C.12: Response time to emergency - historical performance

DESCRIPTION	FY20	FY21	FY22	FY23	FY24
Percentage of emergency events reached in 180 minutes	100%	100%	100%	100%	100%

Network reliability

We measure our reliability performance using two key metrics:

- **Unplanned interruptions:** occur when the supply is interrupted for more than one minute due to issues such as equipment failure, pipeline defects, or gas supply restrictions arising from production plant trips.
- **major interruptions**: are defined in partnership with the critical contingency operator, as those that trigger curtailment notices to prevent potential network collapse, as defined by the issuance of curtailment directions beyond Band 1.

Our KPIs reflect our commitment to minimising these events. However, in the past two years we have not met our internal targets for unplanned interruptions, despite ongoing vigilance and continual investment in system reliability. Encouragingly, our current performance for major interruptions remains strong, with no major events recorded in recent years.

Our current target is zero.

Table C.13: Unplanned and major interruptions – historical performance

DESCRIPTION	FY20	FY21	FY22	FY23	FY24
Number of unplanned interruptions	0	0	0	9	4

Description	FY20	FY21	FY22	FY23	FY24
Number of major interruptions	0	0	0	0	0

Compressor availability

Compressors are critical to the performance of the transmission network. Without them, the system is unable to consistently deliver contractual capacity to consumers. It is therefore important to monitor the reliability performance of compressors to ensure the reliability of the system.

Historical performance has not met the required target levels. Compressor availability and reliability is expected to remain below target until the compressor rightsizing and optimisation programme is complete.

Compressor availability targets are as follows:

- Maintain compressor fleet reliability (excl. planned outages) > 97%
- Maintain compressor fleet availability (incl. planned outages) > 95%

Table C.14: Compressor availability – historical performance

Description	FY20	FY21	FY22	FY23	FY24
Compressor fleet reliability	93.06%	95.37%	92.49%	92.58%	95.52%
Compressor fleet availability	89.50%	91.91%	83.81%	73.90%	83.16%

Public reported escapes and gas leaks

Public reported escapes are commonly used in New Zealand and Australia to measure the integrity of a gas transmission network. Escapes are defined as any confirmed escapes of gas, excluding third party damage events, routine survey findings and no traces events.

Our performance in managing public reported gas escapes and leaks remains consistently strong. We continue to meet our target in this area, reflecting a significant organisational focus on upholding network integrity.

Our target for publicly reported gas leak escapes is to maintain a rate of no more than five incidents per 1,000 kilometres of pipeline. With a transmission network exceeding 2,500 kilometres in length, this equates to a target threshold of 7.5 events.

Table C.15: Public reported escapes and gas leaks - historical performance

Description	FY20	FY21	FY22	FY23	FY24
Public reported escapes and gas leaks per 1000km	3.6	2.38	1.59	2	3

C.4.2. Safety

Our health and safety team routinely monitor health and safety performance of all personnel and companies engaged in our business. We have a strong safety culture where all incidents are reported and reviewed weekly to ensure the appropriate level of incident investigation and ownership follows.

Our lost time injury target is zero.

As depicted in the table below, our performance from FY22 to FY24 has not met our required target levels. While our lost time injuries are generally minor (sprains and strains) we continue to increase our focus on training, critical risks, particularly those that can result in serious injury or fatality, updating procedures and practices to accommodate latest industry practice.

Table C.16: Safety - historical performance

Description	FY20	FY21	FY22	FY23	FY24
Lost time injuries	0	0	1	1	1

C.4.3. Compliance

Below we discuss performance against our compliance-related measures.

Environmental

Our purpose is to provide a safe and reliable gas supply to all customers in a safe and reliable manner that minimises any adverse impact on the environment. We will comply with all legislative requirements and where possible exceed these. The policy commits to protecting the environment for employees, contractors, communities, visitors, customers, and future generations, and aims to continually improve our practices.

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

Table C.17: Environmental – historical performance

Description	FY20	FY21	FY22	FY23	FY24
Environmental breaches or non-compliance	0	0	0	0	0

Annual pipeline certification survey

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

Our goal is to achieve zero non-compliances during our annual certification survey. If a non-compliance is identified, we work promptly to agree on corrective actions and timelines with the certifying body, ensuring that every issue is addressed and resolved within the agreed period.

Table C.18: Compliance - historical performance

Description	FY20	FY21	FY22	FY23	FY24
Number of non-compliances	1	2	2	0	0

C.5. Technical standards and legislation

Our network is designed to meet the transmission system security standard and 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 of gas transmission assets, in general, cannot conform to standardised designs due to the complex and 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 efficiencies are made.

C.5.1. Engineering principles

The following engineering principles ensure a consistent and effective approach to asset management.

- Compliance with standards and regulations (e.g., AS/NZS 2885, ISO 55001).
- Integration of safety, environmental, and risk management principles.
- Alignment with our corporate mission and values.
- Commitment to continuous improvement and stakeholder engagement.
- Efficient capital and operational expenditure planning.

C.5.2. Pipeline management system

The pipeline management system is central to our asset management and meets regulatory requirements for operating high-pressure natural gas pipelines. The manual details the systems, documents, and processes that define our technical obligations.

We follow the AS/NZS 2885 standards, specifically AS 2885.3, which mandates a documented and approved pipeline management system for gas transmission operators, detailing minimum content, management, review, approval, and communication requirements to ensure pipeline safety and integrity.

Our pipeline management system is designed to not only comply with but exceed these standards, incorporating operational, corporate, commercial, and regulatory requirements, including links to corporate governance, third-party relationships, and strategic asset management. The pipeline management system manual serves multiple purposes, as follows.

- It provides a comprehensive overview of the systems, processes, and controls in place to ensure the safe and reliable operation of the gas transmission network.
- It demonstrates compliance with AS 2885.3 and other applicable standards for audit and certification purposes.
- It outlines the delegation of responsibilities and approvals
- It links to supporting plans and procedures, including the pipeline integrity management plan, emergency response plan, environmental management plan, and risk governance guideline.

The pipeline management system is reviewed and updated regularly to reflect changes in regulatory requirements, operational practices, and organisational structure. It is a living document that supports continuous improvement and ensures that we maintain a high standard of pipeline safety and performance.

Safety in design

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

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

C.5.3. Legislation and standards

Below is a collection of some of the regulations and standards that guide our approach to maintaining, operating, and constructing the gas transmission network.

- Health and Safety in Employment (Pipelines) Regulations 1999
- Health and Safety at Work Act
- Health and Safety in Employment (Pipelines - Design, Construction, Operation, Maintenance, Suspension, and Abandonment Requirements) Safe Work Instrument 2023
- Gas (Safety and Measurement) Regulations
- Civil Defence and Emergency Management Act
- Hazardous Substances and New Organisms Act
- The Electricity Act 1992
- Electricity (Safety) Regulations 2010
- AS(/NZS) 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 using protective coatings
- NZS 4853 Electrical Hazards on Metallic pipelines
- NZS 5263 Gas Detection and Odorization
- AS/NZS3000 Electrical installations
- AS/NZS 3788:2006 Pressure Equipment In-Service Inspection standards
- AS/NZS60079 Design, selection and installation of electrical equipment in hazardous areas.

Appendix D. LIFECYCLE MANAGEMENT

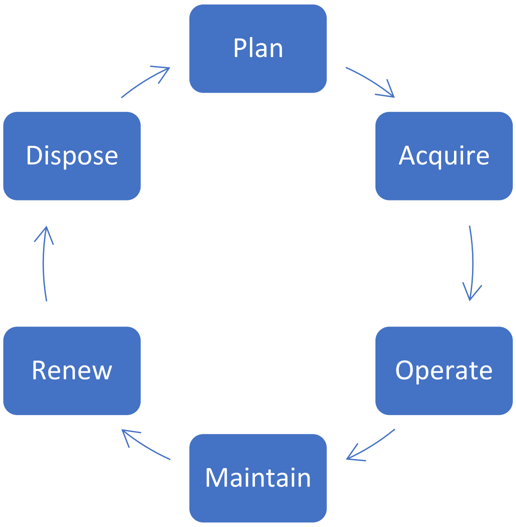
Our approach to lifecycle management mirrors leading practice found in many asset management frameworks aligned with ISO 55001. Our process is systematic and reflects the inherent lifecycle of assets on that we plan, acquire, operate, maintain, renew, and ultimately dispose of assets.

In the context of New Zealand's reduced gas supply and price changes, our approach is evolving. External pressures are shaping our current asset strategies and decision-making processes, influencing our approach to renewal investment. Transmission assets, by their nature, are capital-intensive and long-lived. Traditionally, our strategies favoured investments with decades-long periods to recover our capital. Yet with the ongoing risk of asset stranding, especially as the gas landscape grows increasingly uncertain, we are now re-examining whether the long-term horizon remains optimal for every asset class.

Where previously we would not have endorsed short-term remediation to address asset issues, today such options are increasingly becoming part of our strategic approach. This flexibility allows us to strike an appropriate balance between maintaining the safety and resiliency of our network while minimising long term costs to customers and the risk of over investment and subsequent asset stranding.

We utilise a lifecycle based approach to asset management as depicted below.

Figure D.1: Lifecycle management phases.



A description of the main activities we undertake across each phase are set out below.

- **Plan:** identify future needs using demand forecasts, risk assessments, and stakeholder input, guided by long-term investment models and asset strategies.
- **Acquire:** invest in new or upgraded assets to maintain service and security standards, with safety-in-design and compliance with AS/NZS 2885.
- **Operate:** manage the network safely and efficiently with real-time monitoring, SCADA systems, and structured event response.
- **Maintain:** apply risk based preventive and corrective maintenance to preserve asset performance.
- **Renew:** replace or refurbish assets based on condition, performance, and risk triggers, with decisions supported by lifecycle cost analysis.

- **Dispose**: remove assets that no longer add value or pose increased risk, considering environmental impacts, costs, and reuse opportunities.

We constantly monitor and intervene on our network to keep it safe and reliable for our staff, contractors, gas users, and the general public. When making decisions about when to fix or upgrade our equipment, we look at things like how well it's working, how safe it is, and what it costs to keep running.

There is growing uncertainty about the long-term future of natural gas in New Zealand. Because of this, we're carefully considering our investments, avoiding long-term capital investment that could leave us with stranded assets if demand reduces or regulations change. We're increasingly focusing on flexible, short-term solutions that let us adapt quickly as we continue delivering safe and reliable services.

D.1. Asset interventions

This section sets out the main asset interventions undertaken on the gas transmission network.

D.1.1. Asset renewal

Asset renewal is often required to address asset deterioration and to ensure the network remains in a serviceable and safe condition. As the level of deterioration increases, the asset reaches a state where ongoing maintenance becomes ineffective or excessively costly. Once assets reach this stage renewal is considered, which typically includes one of the following:

- **replacement capex:** to replace assets with like-for-like or new modern equivalents, or
- **refurbishment capex:** extends an asset's useful life or increases its functionality.

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

We assess the likelihood and consequences of asset failures, prioritising investments where the potential risks to safety, reliability, or compliance are greatest. This ensures our resources are directed towards the areas of highest impact, allowing us to proactively manage potential threats before they materialise.

D.1.2. Maintenance

Our maintenance regime is designed to ensure that assets safely achieve their expected life and meet performance levels. Information obtained during maintenance work is used to guide future maintenance programmes and inform renewal decisions. The overarching aim of maintenance is to maintain all assets to ensure a safe, efficient, reliable, and compliant network.

A suite of asset maintenance standards exists that describe the approach to maintaining asset fleets. While approaches differ across asset types, the standards generally specify:

- required asset inspection frequency
- routine and special maintenance activities to be carried out during inspections
- condition testing requirements and prescribed responses to test results
- for certain asset classes, maintenance is primarily driven by compliance with regulations and codes

- maintenance of proprietary items follows vendor manuals and internal specifications.

Inspection intervals are subject to review based on inspection outcomes and regulatory limits.

Our maintenance programmes are prepared through a collaborative approach involving the asset management, engineering, transmission operations, and specialist services teams. Maintenance works are delivered by internal resources, with oversight and certification provided by qualified personnel or accredited inspection bodies as required by the equipment class and regulatory framework.

Maintenance objective

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

During the planning period, the main strategies to achieve this objective include the following.

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

Maintenance activity drivers

The approach to maintenance is influenced by several factors. These include the number, type and diversity of the asset fleets, their condition and age, legislative requirements, environmental factors and third-party activity. Several considerations are accounted for when setting maintenance requirements.

- **Pipeline certificates of fitness:** prescribes mandatory conditions for the performance of operations and maintenance. Other mandatory requirements are included in various acts, regulations and standards.
- **Industry practice**: maintenance practices have largely evolved over the past 40 years. Australian standard 2885.3 covers gas pipeline operation and maintenance and is the main reference for these activities. Other obligations fall into the category of good industry practice and are found in various New Zealand, Australian and international standards and codes.
- **Fault analysis**: root cause analysis is undertaken when significant defects occur. This is supplemented by fault trend analysis. If performance issues with a particular type of asset is identified, and if the risk exposure warrants it, a project will be developed to carry out 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

Reflecting the above drivers, overarching maintenance programmes have been developed for pipelines and stations. These are set out in the following documents:

- station maintenance management plan
- pressure equipment management plan
- pipeline integrity management plan.

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.

This approach is reviewed and updated based on any new information. The transmission operations team contributes to, and forms an integral part of, this continuous improvement process. Anomalies 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.

Below we describe the main maintenance categories used in the AMP.

Routine and corrective maintenance and inspection (RCMI)

After new assets are commissioned RCMI activities begin. As an asset ages and its condition declines, the cost of corrective repairs to maintain fitness for purpose will escalate until it becomes more cost-effective to decommission or replace it. Ongoing condition monitoring is used throughout the asset's life to identify when the asset should be decommissioned.

Maintenance strategies and plans are developed. These determine maintenance activities and frequencies. The frequencies defined in the maintenance plans provides schedules and intervention guidelines for maintenance on the assets.

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

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

Service interruptions, incidents and emergencies (SIE)

The occurrence of incidents on the network result in the need to carry out activities to understand the nature of the incident 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 fault at a station where safety or supply integrity could be compromised
- remediation or isolation of unsafe network situations.

Every reasonably practicable precaution is taken to prevent third party interference with pipelines including thorough rigorous surveillance 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.

Maintenance forecast

The table below sets out our overarching RCMI forecast across our main asset classes.

Table D.1: RCMI maintenance forecast expenditure (RY25$ 000s)

Asset Category	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Pipelines	3,245	3,695	3,245	3,245	3,245	3,245	3,245	3,245	3,245	3,245
Compressors	3,934	4,184	4,234	4,284	4,334	4,384	4,434	4,484	4,534	4,584
Stations	10,283	11,506	12,176	12,176	12,226	12,276	12,326	12,376	12,426	12,476
Special Crossings	47	47	47	47	47	47	47	47	47	47
SCADA & communications	23	120	120	120	120	120	120	120	120	120
Other assets	500	500	500	500	500	750	750	850	950	1050

D.1.3. Asset relocations

Urban encroachment continues to exert pressure on our gas transmission network. The expansion of subdivisions, major roadways, and the increase in numbers of facilities such as schools and medical centres are transforming what were once rural pipeline corridors into urban environments. This evolution needs a proactive approach to ensure safety as when a pipeline is reclassified from rural to urban, additional controls are required to mitigate the increased risk.

Measures to address this may include the installation of enhanced signage, the application of protective concrete slabs where pipeline design permits, replacement of the existing pipeline designed for urban locations, or in certain scenarios, a reduction in operating pressure to limit the consequences in the unlikely event of a failure. Reducing pipeline pressure can lower the system's ability to deliver the gas volumes.

Forecasting relocation requirements remains challenging, as the need is often dictated by the unpredictable pace and scope of developer-driven activity. Furthermore, there is ongoing debate over how the associated costs should be allocated. While developers sometimes express dissatisfaction at being required to fund asset relocations, the alternative, socialising these costs onto wider end consumers through higher gas bills, raises broader questions of fairness and equity. This tension underscores the importance of transparent stakeholder engagement.

D.1.4. Delivery model

We use a mix of insourcing and outsourcing approaches for works delivery. This approach is currently considered appropriate and is driven by the concept of having scarce and specialised skills supplied internally. Where the skill set is more broadly available and a competitive market exists, then outsourcing is preferred.

Capital works delivery

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

Maintenance delivery

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

Asset inspections and maintenance work is delivered by the transmission operations and specialist service teams in accordance with the applicable standards and inspection schedules for each class of asset.

The resources employed by the teams are mainly in-house and are supplemented using external contractors to balance workload requirements. The teams are responsible for planning and scheduling maintenance requirements and ensuring that sufficient competent resources are available to deliver against requirements. Progress against the maintenance schedules and the associated maintenance costs are monitored monthly.

D.1.5. Standardised equipment and designs

Where feasible standardised equipment and designs are used on the transmission network. Typically, standard designs are introduced to avoid producing bespoke solutions for similar network installations. We have adopted the approach that when a design is repeatedly used on the network, a standard design is developed. Subsequently, as design improvements are identified standard designs are amended and updated.

Standardised design provides the following advantages:

- ensures a rigorous equipment selection process to select fit-for-purpose units while ensuring appropriate equipment performance over the life of the equipment
- delivers cost savings in design
- lowers project costs through competitive bulk materials supply agreements
- simplified procurement and reduced stockholding
- standardised maintenance practices
- reduced rework during construction
- safer outcomes and improved mechanism for capturing incremental improvements.

D.1.6. Decommissioning

Pipeline and station decommissioning, suspension and abandonment are managed according to the pipeline management system manual, which complies with the requirements of AS 2885.3. The manual defines roles and procedures for the safe, sustainable, and compliant decommissioning, suspension, and abandonment of pipelines and stations. All actions are documented within this framework to meet regulatory obligations, maintain traceability, and comply with safety and environmental standards.

Decommissioning

Consistent with the standards under which we operate, the following definition applies to our use of the term decommissioning.

- decommissioning refers to the process of safely removing a pipeline or station from active service permanently and assets remain in situ

The following roles and documents govern this process:

Table D.2: Roles and responsibilities for decommissioning.

AREA	RESPONSIBLE PERSON OR ROLE	RELEVANT PROCEDURES OR REGULATIONS	KEY RESPONSIBILITIES
Governance and approvals	Manager, Engineering Services	AS 2885.3, abandonment procedure	Abandonment plans
Operational responsibilities	Manager, Operations (Pipeline Manager)	Regulation 5 of Health and Safety in Employment (Pipelines) Regulations 1999	Decommissioning activities, field works, surveillance
Change management and risk control	Not specified	Management of minor technical change procedure, risk item register	Manage technical/operational changes, risk prioritisation and oversight
Landowner and stakeholder engagement	Manager, Land and Planning	Not specified	Landowner communications, easement management, corridor protection, stakeholder engagement
Documentation and compliance	Not specified	Pipelines management system manual	Documentation, regulatory compliance, traceability, safety, environmental considerations

D.2. Asset overview

Gas transmission networks are made up of several distinct asset types. We have categorised these into several asset classes with related asset fleets. These are broadly aligned with information disclosure reporting categories.

D.2.1. Asset hierarchy

Table D.3: Asset categories

ASSET CLASS	ASSET FLEET
Pipes	Steel pipes Special crossings
Compressors	Turbine driven compressors Reciprocating engine driven compressors Electric driven compressors
SCADA and communications	Remote terminal units Communication terminals

Asset class	Asset fleet
Other Stations	Pigging facilities Pressure regulators Pressure relief valves Isolation valves Filters Buildings and ground
Station components	Main line valves Heating systems Odorisation plant Coalescers Metering systems Cathodic Protection Gas chromatographs

D.2.2. Asset population

The following table sets out asset populations for our main asset categories (classes) and related fleets.

Table D.4: Asset populations (as at 16 September 2025)

Asset class	Asset fleet	Units	Quantity
Pipes	Protected steel pipes	km	2510
Pipes	Special crossings	km	8
Compressors	Compressors-turbine driven	No.	4
Compressors	Compressors-electric motor driven	No.	2
Compressors	Compressors-reciprocating engine driven	No.	14
Stations	Compressor stations	No.	9
Stations	Offtake point	No.	123
Stations	Scraper stations	No.	14
Stations	Intake points	No.	9
Stations	Metering stations	No.	5
SCADA and communications	Remote terminal units (RTU)	No.	88
SCADA and communications	Communications terminals	No.	3
Main-line valves	Main line valves manually operated	No.	94
Main-line valves	Main line valves remotely operated	No.	11
Heating systems	Gas-fired heaters	No.	100
Heating systems	Electric heaters	No.	4
Odorisation plants	Odorisation plants	No.	24
Coalescers	Coalescers	No.	37
Metering systems	Meters-ultrasonic	No.	10
Metering systems	Meters-rotary	No.	69
Metering systems	Meters turbine	No.	81
Metering systems	Meters-mass flow	No.	1

Asset class	Asset fleet	Units	Quantity
Cathodic protection	Rectifier units	No.	48
Chromatographs	Chromatographs	No.	13

D.3. Pipelines

Our pipelines are the backbone of our gas transmission network. These pipelines vary in nominal bore from 50 millimetres to 850 millimetres and are predominantly installed underground.

D.3.1. Steel pipes

Asset overview

Steel pipes are comprised of high-grade carbon steel pipelines engineered to adhere to rigorous industry standards. These pipelines vary in nominal bore from 50 millimetres to 850 millimetres and are predominantly installed underground. In compliance with regulatory requirements, pipes with increased wall thickness are utilised in urban areas or at crossings of roads, waterways, or railways. However, certain geographical or infrastructural limitations necessitate the installation of above-ground sections. Such above-ground pipelines are supported by purpose-built structures, bridges, or other engineered solutions referred to as special crossings (discussed in the following section).

Our buried pipelines are protected from corrosion using various coating technologies. In the 1960s and 1970s, coal-tar enamel or Polyken tape wraps were commonly used. Since the 1980s, extruded polyethylene (often referred to as 'yellow jacket' or '2LPE') or fusion-bonded epoxy coatings have been standard. More recent installations typically utilise dual-layer fusion-bonded epoxy with liquid epoxy for field joints, which offers improved corrosion resistance and helps mitigate issues such as cathodic protection shielding and stress corrosion cracking. An impressed current cathodic protection system is installed to provide additional defence against corrosion, compensating for any coating defects or deterioration that may occur over time.

Most of our pipelines are situated on land where formal easement rights have been established with landowners, ensuring access. Some segments located in public roads are covered by statutory access rights, while facilities on large customer properties are included in commercial supply agreements. There are also instances of pipelines on land owned by private parties, government, Iwi, businesses, or local authorities, often constructed prior to current environmental legislation. In these cases, existing statutory rights still apply. However, in some areas there may be pipelines that are in road reserves or otherwise do not have an easement. This is primarily due to urban encroachment or development.

There are additional assets that are not located within the easement. These are referred to as off-pipeline assets and are predominantly civil construction type assets. Depending on construction, they may require routine maintenance plans to ensure they are maintained to a suitable standard. These assets may include the following:

- retired land blocks
- access tracks and culverts
- crib or retaining walls
- fencing and drainage
- ground water monitoring equipment

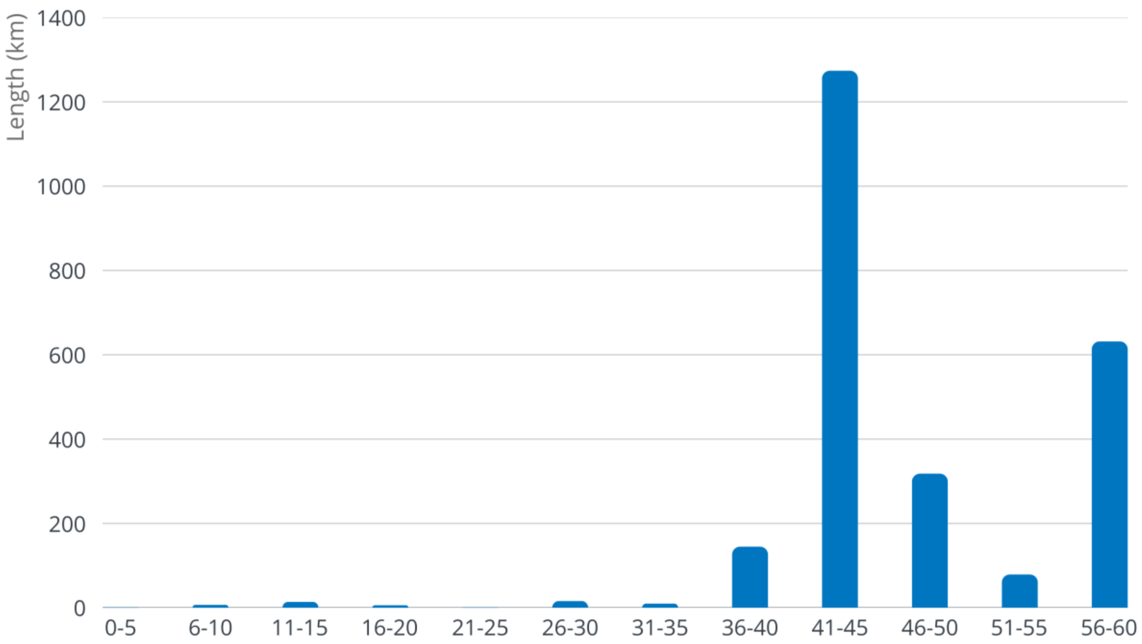
– land movement monitoring equipment.

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

Age profile

Figure D.2 below illustrates that a large proportion of the pipelines are over 30 years old. As pipeline age increases, specific attributes of the pipeline can deteriorate. Generally, pipeline deterioration comes in the form of corrosion, due to a combination of ageing/failing external corrosion and inadequate cathodic protection. Pipe wall deformations (dents, wrinkles, buckles, etc.), or environmental cracking are generally due to changing land conditions (geohazards), sometimes assisted by a corrosive environment (cracking). Pipelines are replaced or realigned when there are specific triggers to do so.

Figure D.2: Pipeline age profile



Condition and performance

Condition assessments indicate that the overall pipeline fleet is in reasonable condition and that no excessive or generalised widespread deterioration has occurred. However, routine maintenance and inspection of pipelines has revealed specific instances where remedial work will be required to maintain pipeline integrity.

Several activities or changes in condition can affect the pipeline network and may alter the identified risk level. Such changes include urban encroachment, unauthorised activities, emerging pipeline integrity concerns, geohazards, coating deterioration, corrosion, and the findings of routine audits and inspections.

Fitness for purpose assessments are conducted every ten years on individual pipelines. The fitness for purpose assessments considers the design standard, construction quality, material quality, operational stresses, maintenance history, asset working environment and external stresses to evaluate current condition and determine fitness. Previous pipeline assessments were completed in 1997, 2007 and 2017, with the next review scheduled for 2027.

In addition to fitness for purpose assessments, safety management study (SMS) reviews are carried out as part of a rolling programme and conducted at a minimum of every five years.

The SMS process reviews standard threats to the network and assesses the risk each threat poses to the public, environment, and supply. Risks are evaluated in accordance with current mitigation controls and changing land use (e.g. rural vs. urban areas) along each pipeline's route. Any areas of the pipeline that require specific additional measures are determined and actioned through this process. Any actions identified as part of the SMS are implemented to either change or improve maintenance and surveillance routines, and renewal programmes to ensure that risks are reduced to a level that is as low as reasonably practicable (ALARP). The SMS reports are independently assessed by Lloyds Register.

Risks and issues

We face many threats/issues in relation to buried pipelines, and we actively adapt our asset strategies to improve our management of these risks by updating controls, changing maintenance plans, and reviewing technology advances that can be leveraged. These efforts aim to minimise threats and ensure the continued safe operation of our pipeline network.

Table D.5: Threat and issues

No.	Threat or issue	Description
1	Unpiggable pipelines	Unpiggable pipelines are those that cannot be inspected internally using in-line inspection (ILI) tools, making it more challenging to detect and address anomalies such as corrosion or other integrity threats. Alternative inspection and monitoring methods, such as external surveys and pressure testing, are required, which may be less effective or more disruptive.
2	Pipeline material or construction defects	Pipelines may have inherent material flaws or construction defects such as poor welds, substandard materials, or deviations from design standards. These defects can compromise pipeline integrity, increasing the risk of failure over time, especially under stress or adverse environmental conditions. Construction defects are typically identified during pre-commissioning pressure testing and rectified accordingly. Ongoing monitoring and targeted repairs are necessary to manage these risks.
3	External interference	External interference includes third-party activities such as excavation, construction, or accidental impacts that can damage pipelines. This threat is heightened in areas with urban development or agricultural activity. Controls include public awareness campaigns, clear signage, protective barriers, and coordination with local authorities to prevent accidental damage.
4	Urban encroachment	Urban encroachment increases pipeline risk by bringing building developments and other infrastructure closer to pipelines. This is particularly concerning for older pipelines not built to modern standards, as they may have gaps from a safety perspective when compared to current design standards. To mitigate these risks, controls such as public signage, protective slabs, upgrades or replacements of vulnerable pipelines, or reduced operating pressures are put in place to protect both people and assets.
5	Geohazard risk	Geohazards, including landslides, floods, erosion, and earthquakes, pose risks to pipeline safety by causing ground movements that may result in bending, rupture, or containment loss. Pipelines in areas prone to such events are especially vulnerable, with consequences ranging from supply loss to environmental and property damage. Operators document significant geohazard risks and assess their potential impacts according to industry standards like AS2885, ensuring risks are managed and public safety is prioritised.

No.	Threat or issue	Description
6	Corrosion	Corrosion impacts both the inside and outside of carbon steel pipelines. Externally, moisture, acidic soils, and damaged coatings can lead to corrosion, especially if cathodic protection systems fail. Internally, corrosion is caused by water, acidic gases, and contaminants in the gas stream, particularly in stagnant areas. To manage these risks, pipelines are protected with coatings, cathodic protection, dehydration of the gas stream, regular inspections, and cleaning operations.
7	Stress corrosion cracking (SCC)	SCC occurs when corrosion combines with tensile stress, leading to environmentally assisted cracking in pipelines. Both axial and circumferential SCC threaten critical transmission lines, notably the 100, 200, and 400 lines. Recent EMAT inspections have targeted the 400B pipeline, with ongoing management of affected 200 line sections through reduced pressure and frequent checks. While crack-detection tools for the 100 and 200 lines are currently unavailable, they may be considered as technology advances. Our updated SCC management plan, set for rollout in FY26, emphasises EMAT inspections, segment-based risk assessment, targeted pressure reductions, and continued non-destructive crack testing. Budgets and work priorities have been adjusted to support these initiatives, with a reassessment planned for FY26, potentially including alternative funding mechanisms.
8	Selective seam weld corrosion	Selective seam weld corrosion is a time-dependent threat, occurring as axially oriented corrosion along the longitudinal weld seam of certain welded pipes, especially those produced using older manufacturing methods like our pre-1971 8" pipe. This corrosion risk results from historical metallurgical practices and environmental exposure, mostly impacting ageing pipeline sections. To manage it, we focus on direct excavation assessments and increased internal inspections to enable early detection and targeted mitigation on susceptible pipelines.

Pipeline risk mitigation

To effectively address the various threats and issues facing our pipelines, we implement targeted controls and mitigation strategies. The following table summarises these controls for key pipeline risks.

Table D.6: Pipeline consequence and controls

No.	Threat or issue	Consequence	Controls
1	Unpiggable pipelines	Increased risk of undetected pipeline anomalies, including internal corrosion, leading to loss of containment over time.	DCVG surveys, line walks, easement surveillance. Dry gas pipelines are not typically susceptible to internal corrosion.
2	Pipeline material or construction defects	Pipeline loss of containment due to undetected girth or seam weld anomalies, mid-wall anomalies (e.g. laminations), or the fatiguing of pipe wall deformations (e.g. dents, wrinkles, ripples, or buckles) over time.	Pre-commissioning hydrotest for girth and seam weld, and mid-wall anomalies. In-line inspection for girth weld and mid-wall anomalies, and pipe wall deformations. Direct inspections.
3	External interference	Pipeline loss of containment (leak or rupture) with potential ignition of natural gas due to unpermitted ground disturbance activities across gas pipeline easements. Risk of seriously injury or fatalities in proximity to the pipeline. Property damage. Loss of gas service to communities or major urban centres.	Pipeline materials/design (wall thickness, material grades) and depth of cover. Buried pipeline marker tape. Pipeline easement surveillance. Permit to work system. Landowner communications and education. Liasson with local and regional councils. Contractor awareness programmes. One call / beforeUdig systems.
4	Urban encroachment	Increased risk of third-party interference, accidental damage, reduced access for	Land use monitoring, safety management studies, pipeline location

Firstgas

No.	Threat or issue	Consequence	Controls
		maintenance, change in measurement length.	class, stakeholder engagement, urban planning coordination, signage
5	Geohazard risk	Damage or failure from landslides, floods, erosion, or other ground movement	Drone and easement walking surveys, satellite imagery, geotechnical and field technician line flights GIS monitoring, emergency response planning, Pipeline strain monitoring, geohazard monitoring.
6	Corrosion	Pipeline degradation, leaks, or rupture from coating defects or failed cathodic protection	Coating replacement, rectifier units, DCVG surveys, enhancing cathodic protection performance monitoring, investigative monitoring
7	Stress corrosion cracking	Crack formation and potential rupture due to combined corrosion and tensile stress	EMAT ILI tools, direct inspections, non-destructive testing (NDT), pressure reduction, SCC management plan, regular updates and reassessment
8	Selective seam weld corrosion	Axially oriented leaks or ruptures at weld seams, particularly in pre-1971 8" pipe	Direct inspection, advanced ILI data processing, excavation, scheduled pipeline work

Lifecycle management

Our strategy and guidelines for pipeline maintenance and renewal are contained in the pipeline integrity management plan. The management plan sets out the pipeline monitoring and maintenance activities to be undertaken to support the safe and reliable operation of the asset in guidance with relevant standards.

Maintenance

The following summary provides an overview of pipeline and inspection activities we undertake to maintain integrity and ensure the safe, reliable operation of our assets. These activities are guided by the pipeline integrity management plan, which outlines both proactive and reactive measures. This includes planned inspections, direct assessments, and the adoption of new technologies to address emerging risks and adapt to evolving industry standards.

Table D.7: Maintenance and inspection activities.

Activity	Description	Frequency
Safety management study	A safety management study is a systematic review conducted every five years to assess and manage risks to pipeline integrity, ensuring safety and reliability, with outcomes that may alter maintenance routines and risk management practices.	5 years
Fitness for purpose assessments	A formalised review and assessment of pipeline operating conditions, anomalies and anomaly degradation rates, system limitations (materials, valves, and other equipment), system safety and integrity controls, changes in environmental factors, and isolation plans to demonstrate that the pipeline system can be safely operated for the next 10 years.	10 years
Pipeline and easement inspection and surveillance	Pipeline surveillance includes routine inspections by road, air, and foot, as well as non-routine patrols following events like storms or earthquakes. Surveillance frequency is determined by the risk of external interference or the consequence of pipeline failure. New monitoring technologies, such as drones, are being considered to enhance pipeline surveillance and reduce risks.	
	Aerial surveillance. Monthly or bi-monthly aerial surveillance is conducted.	1 or 2 months

Activity	Description	Frequency
	Vehicle road surveys. High-risk areas receive daily road patrols, while specific urban locations are patrolled between 1 day and 3 month frequencies.	1 day-3 months
	Easement walk surveillance on higher risk or special locations.	3 months
	Easement walks for signage and post painting. Every pipeline is also walked every three years to update signage and repaint posts marking the pipeline easement, ensuring clear identification and ongoing asset integrity	3 years
Direct current voltage gradient (DCVG) surveys	Where in-line inspections are not possible, above ground inspections of buried pipeline coating condition and cathodic protection leakage are carried out as the primary method for detecting coating degradation. Surveys are performed by trained cathodic protection technicians, who walk the full pipeline route equipped with specialised tools to identify and assess coating and protection issues.	5 or 10 years
Pipeline in-line inspections	Pipeline in-line inspection is our primary approach for identifying corrosion and anomalies. We use intelligent devices that run inside the pipeline which detects corrosion, strain, and other signs of pipeline degradation. Inspection frequency is risk-based.	
	High consequence areas	5 years
	Remaining locations	10 years
	We operate cleaning pigs at intervals between 6 and 24 months, depending on the historical cleanliness of each pipeline. This method effectively removes contamination and helps prevent further degradation, ensuring the ongoing integrity of our pipeline network	6-24 months
Pipeline direct inspections	Direct inspections involve the excavation of our pipelines to review and confirm the results of ILI and DCVG surveys. During a direct inspection, the external coating is removed, and the pipe wall is inspected for corrosion, deformations (e.g. dents, ovality, buckling), cracking, and mid wall anomalies (e.g. laminations) using non-destructive testing (NDT) techniques such as ultrasonic testing, magnetic particle inspections, and 3D scanning.	As required
Reactive maintenance	Reactive maintenance is undertaken whenever threats to pipeline to integrity emerges. Such threats can arise from a range of sources, most notably external interference, like unauthorised third-party activities within the easement, which can compromise the system unexpectedly. Geotechnical risks, such as ground movement or subsidence, may also trigger a rapid response, as can the detection of potential anomalies following the completion of in-line inspections.	Reactive

In-line inspection program

The table lists each pipeline's required inspection frequency and last inspection date.

Table D.8: Pipeline in-line inspection program.

Pipeline No.	Pipeline location	Frequency (years)	Last inspection
100	Kapuni–Waitangirua	5	2021
111	Waitangirua–Tawa A	5	2019
113	Himatangi–Feilding	10	2022
200 [I & II]	Kapuni–Temple View	5	2021
200 [III]	Temple View–Papakura	5	2021
300	Frankley road–Kapuni	10	2023

Pipeline No.	Pipeline location	Frequency (years)	Last inspection
303	Stratford Lateral	10	2023
400 [I]	Oaonui–Frankley road	10	2023
400	Frankley road–Huntly	5	2023
400B	Rotowaro–Southdown	5	2021
403 (I)	Rotowaro–Huntly power station	10	2022
405	Drury–Glenbrook	10	2022
421	Pirongia–Te Awamutu	10	2024
430[I]	Westfield–Henderson	5	2023
430 [II & III]	Henderson–Maungatapere	10	2022
500 [I]	Pokuru–Kinleith	10	2022
500 [II]	Kinleith–Kawerau	10	2021
508	Reporoa–Taupo	10	2024
600A Loop Line (602, 603, 604 & 606)	Hawera–Kaitoke	5	2024
600B Loop Line (601 & 605)	Otaki–Belmont	5	2024
700	Feilding–Hastings	10	2022
800	Lichfield–Kaimai	10	2022

Renewal

When inspections identify anomalies such as corrosion, mechanical damage, or weakened joints our approach involves either refurbishing existing pipeline segments or, when necessary, replacing them entirely. Refurbishment methods may include installing welded sleeves or other engineered repairs to restore structural integrity and extend the pipeline's service life. In circumstances where risks cannot be mitigated by repair alone, for example, if the pipeline is threatened by evolving geotechnical hazards or if increased urban development elevates safety requirements, we may choose to realign or fully replace pipeline sections. This can involve constructing new pipelines in safer locations, upgrading materials to meet modern toughness specifications, or rerouting the line to avoid high-risk zones. Each intervention is guided by an assessment of current and future risks.

Table D.9: Forecast projects for planning period.

Project name	Project description	Expected completion
Awakau wrinkle remediation	Replacement of a pipe spool that has wrinkled due to years of slow land movement down slope. Involves the hot tapping of the 400 Line, the construction of a temporary above ground bypass to ensure security of supply, and removal and replacement of the damaged spool.	12 months
Kaitoke Stream crossing	Realignment project to install new crossings for the pipeline across the Kaitoke and Kohata Streams. Both currently pipelines are exposed or risk exposure due to years of erosion of the stream beds.	12 months
602 & 604 loop line excavation and repairs	Reinforcement of several pipe spools containing pressure-limiting internal metal loss, likely poor material handling and storage techniques during construction. Reinforcement is intended to be by welded sleeve repairs.	12 months

Project name	Project description	Expected completion
400B pipeline EMAT in-line inspection	A project is underway to run an EMAT in-line inspection tool on the 14-inch 400B pipeline. Upon completion, the collected data will be processed and calibrated using multiple excavations to accurately assess the extent of SCC on the pipeline and determine suitable long-term management strategies.	12 months
Pipeline in-line inspection program	Inline inspection of the following pipelines – 100 pipeline Kapuni to Waitangirua – 200 pipeline Kapuni to Papakura – 435 pipeline Maungatapere to Kauri – 504 pipeline Rotorua to Reporoa – 434 pipeline Whangarei OFT to Whangarei DP – 702 pipeline Foley Rd OFT to Pahiatua DP – 800 pipeline Kaimai summit to Te Puke	12 months
Pipeline in-line inspection program	Inline inspection of the following pipelines – 104 pipeline Raumai to Marton – 306 pipeline Kapuni offtake to Kapuni delivery point – 400 pipeline Frankley Road to Mokau – 400 pipeline Mokau to Mahoenui – 400 pipeline Mahoenui to Tihiroa – 400 pipeline Tihiroa to Huntly – 402 pipeline Te Kowhai to East Horotiu – 402 pipeline Kuranui to Morrinsville – 402 pipeline Morrinsville SS to Waitoa DP – 430 pipeline Westfield to Henderson – 502 pipeline Kawerau to Edgecumbe – 507 pipeline Whakatane OFT to Whakatane DP – 601/605 pipelines Otaki SS to Belmont DP – 602/603/604/606 pipelines Hawera to Kaitoke	4 years
200/400 pipe Mathers Road geohazard remediation	Large scale geohazard remediation project that involves stabilising a failing slope directly threatening the integrity of the 200 and 400 Lines.	4 years
605 line wrinkle rectification	Reinforcement of a pipe spool containing a minor wrinkle to ensure that future deformation is mitigated. Reinforcement is intended to be by a welded sleeve repair.	4 years
200-01 Denbigh Rd lamination	Replacement of a pipe spool that contains a long, potentially surface-breaking, mid-wall lamination. Involves the hot tapping of the 200 Line, the construction of a temporary above ground bypass to ensure security of supply, and removal and replacement of the damaged spool.	4 years
Inline inspection program	Execution of in-line inspection program across all piggable pipelines.	10 years
Emergent pipeline anomaly repairs	Projects for the remediation of pipeline anomalies found from in-line pipeline inspections.	10 years
Emergent geohazard remediation	Projects for emergent work due to shifting land, rivers or streams.	10 years

D.3.2. Special crossings

Asset overview

Special crossings are engineered structures designed to allow gas pipelines to traverse obstacles that cannot be crossed by conventional underground installation. These obstacles include rivers, deep gullies, roads, railway lines, dams, and fault zones.

We have different forms, including self-supporting aerial spans that elevate pipelines above rivers or ravines, supported spans on bridges or trusses, and cased crossings where a pipeline is enclosed within a protective casing under roads or railways.

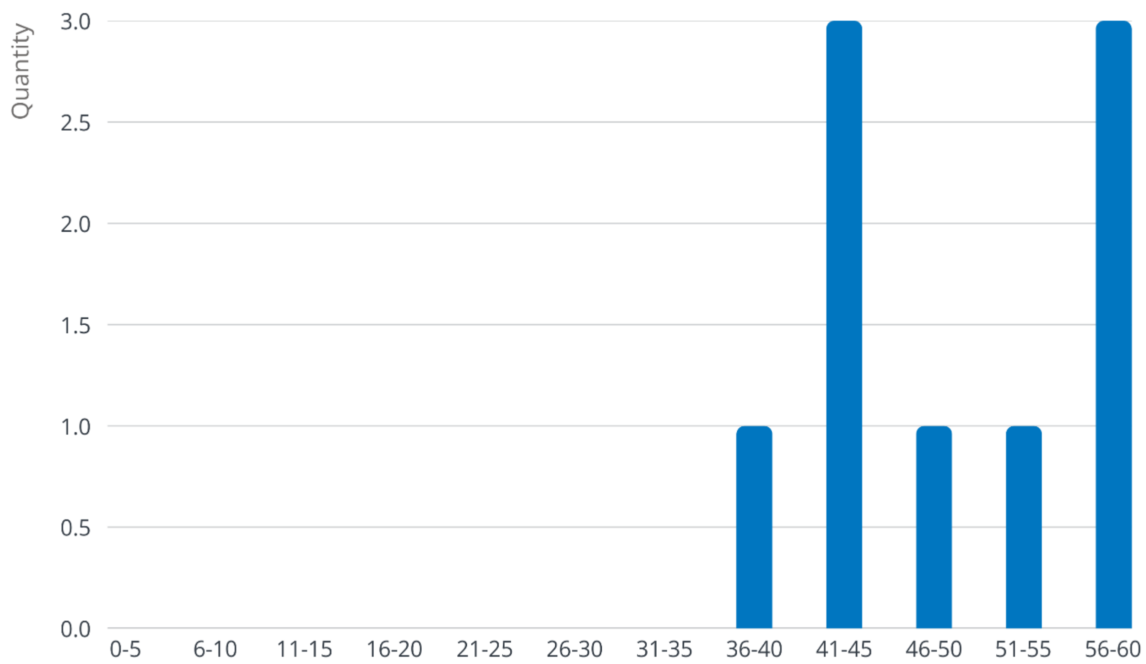
Special crossings are strategically located wherever the pipeline route encounters a natural or man-made barrier. Examples of our special crossings include the Tuakau Pipe Bridge crossing the Waikato River, Arapuni Dam and Head Race Bridge, as well as engineered crossings at sites like Gibbs Fault and Pukearuhe. The choice of crossing type and location is determined by terrain, environmental constraints, safety requirements, and the need to ensure long-term pipeline integrity.

Because of their exposed or inaccessible locations—over water, in road reserves, or at height—special crossings often require tailored inspection, maintenance, and monitoring routines.

Age profile

Figure D.3 shows the age profile of our special crossings' assets as installed during pipeline construction. The age profile doesn't materially influence the condition of coatings if these are maintained and corrosion is prevented appropriately.

Figure D.3: Special crossings age profile



Condition and performance

Programmed condition assessments and surveys are conducted for pipelines at special crossings, covering support structures, ground to air interfaces, and access platforms. Overall condition of special crossing is good.

Carrier pipes in cased crossings on pigged pipelines are generally considered fit-for-service. Casings will be removed when feasible, but compromised casings under roads and railways are challenging to access or repair.

Risks and issues

The primary threat or issue associated with special crossings is that they are generally difficult to inspect and maintain. In many cases, these crossings require specialist labour trained to work at heights or over water and may necessitate landowner access agreements to proceed with necessary works. This challenge is managed by employing specialist workers and implementing thorough project planning.

Lifecycle management

Maintenance

The summary below outlines special crossing maintenance activities. These activities follow guidelines established by the pipeline integrity management plan, incorporating both proactive and corrective maintenance activities.

Table D.10: Maintenance and inspection activities.

ACTIVITY	DESCRIPTION	FREQUENCY
Inspections	Visual inspection of pipeline coating condition, corrosion on or under supports structures, ground to air interfaces and access.	2 years
Coating remediation	Cleaning special crossings coatings of any foreign material, such as guano. Coating repair and remediation.	As required

Renewal

Special crossings are inspected regularly, with renewal triggers determined by either the external condition of the pipeline or supporting infrastructure, in-line inspection anomalies, or the presence of specific threats, such as geohazards. Examples of these drivers include:

- coating condition: renewal may be required when inspections reveal significant deterioration of the external pipe coating, such as widespread corrosion or loss of protective layers. If rust has advanced to the point where remediation through repainting or minor repairs is no longer viable, full renewal becomes necessary.
- internal pipeline anomalies: anomalies detected during in-line inspections such as indications of metal loss, wall thinning, or other internal defects can also trigger renewal, even if the external coating appears sound.
- geohazard or environmental threats: emergent risks from environmental factors like erosion or ground movement, especially near watercourses, may trigger a special crossing to be relocated to a safer location.

Table D.11: Projects forecast for planning period.

PROJECT NAME	PROJECT DESCRIPTION	COMPLETION PERIOD
Fencing replacement and ground works near Waingongoro Stream	Scheduled for FY26; involves replacement of fencing and ground works in the area.	12 months

Ground-air interface replacement near Kai Auahi Stream	Scheduled for FY26; replacement of the ground-air interface for the pipeline near Kai Auahi stream.	12 months
Embankment upgrade near Kai Auahi Stream	Scheduled for FY26; upgrade of the embankment around the pipeline penetration to meet current company standards for stability, security, and drainage.	12 months

D.4. Compressors

D.4.1. Overview

Our compressors fleet comprises three primary categories: turbine-driven, reciprocating engine-driven, and electric motor-driven compressors, each serving distinct operational roles across the transmission network. Turbine drivers, typically paired with centrifugal compressors, are deployed at high-demand sites like Rotowaro and Mokau. Reciprocating drivers, which combine gas engines with reciprocating compressors, are widely used across legacy stations for their adaptability to variable flow conditions. Electric drivers, the newest addition to our fleet, offer the greatest emissions reduction potential, but the high costs associated with upgrading power supplies to remote sites often make their long-term capital investment prohibitive. As a result, we are frequently steered back toward gas-driven engine solutions.

In recent years, we have actively optimised our compressor fleet in response to ageing assets, focusing on right-sizing equipment and modifying operational practices across the network to prevent over-compression and ensure we meet critical contingency thresholds. Our ongoing objective is to install more efficient compressors and continually reduce emissions wherever reasonably practical.

We have an established system security standard for the transmission network that mandates redundancy for rotating equipment at each compression station, commonly identified as the N+1 redundancy requirement. However, as we continue to navigate an environment of uncertainty with increasing risks of asset stranding and an ongoing pressure to minimise costs the appropriateness of maintaining this level of redundancy warrants careful review. It is crucial to assess whether sustaining the N+1 redundancy standard, as written, best serves the interests of our customers and the broader industry, or if a more flexible approach could better align with evolving needs and challenges.

Several compressors within our fleet, which we have maintained to the minimum required standards, are now being considered for full decommissioning. These units are no longer needed due to reduced demand and diminished redundancy requirements, and their continued maintenance and operation cannot be justified.

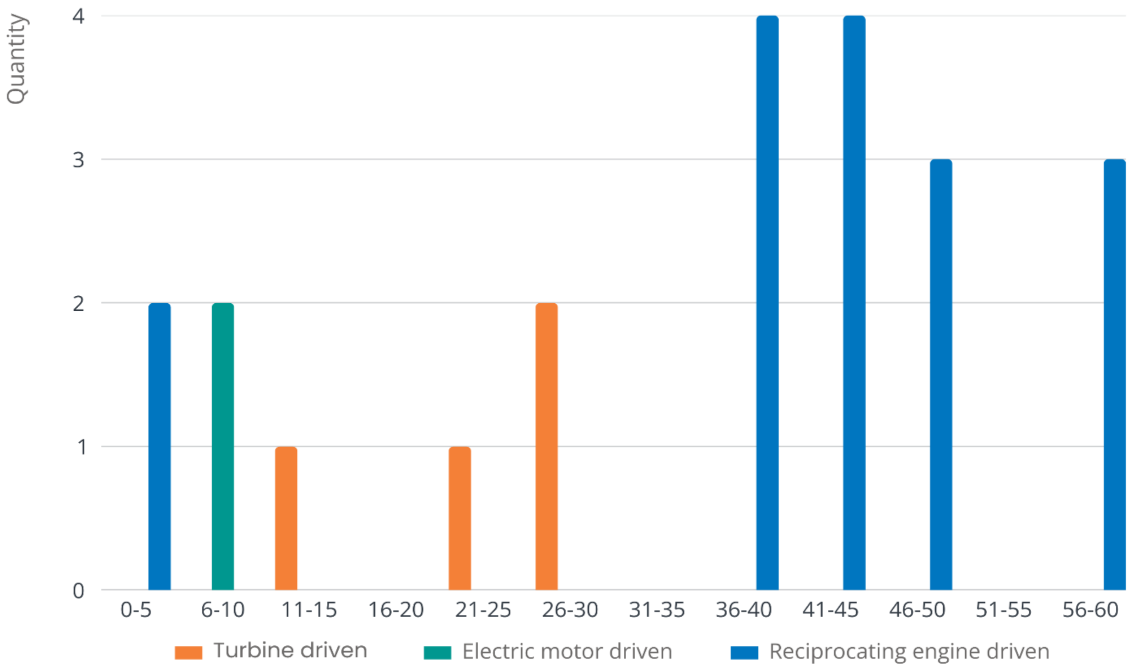
Gas compression stations do not just comprise compression units. The sites need to hold a considerable amount of auxiliary equipment to facilitate compressor operations. Gas detection, filtrations, control systems, actuated valves and back up electrical generators are all part of the system that makes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

Shifting network loads are recognised as a significant factor influencing compressor utilisation, sizing, and investment decisions. Variability in demand can lead to periods where compressors are either oversized or underutilised, increasing the risk of asset stranding, over-investment, or under-investment. Management of these risks is supported by regular review of demand forecasts, asset performance data, and ongoing alignment of compressor fleet strategy with actual and projected network requirements.

D.4.2. Age profile

Figure D.4 shows the age profile of our compressor assets.

Figure D.4: Compressors age profile



Collectively, these assets span a wide age range, with some reciprocating engines dating back to 1969 and turbine units installed in the 1980s and 1990s. While many have undergone major overhauls to extend their operational life, the fleet's age profile presents increasing challenges around reliability, efficiency, and emissions.

Many reciprocating engine-driven compressors in the fleet are past their design life, though some are inactive but not yet decommissioned. While major overhauls can extend their useful life, this ageing trend presents increasing challenges.

The compressor types are discussed in detail in the following three sections, which outline their asset condition, performance, risks, and related lifecycle management strategies.

D.4.3. Turbine driven compressors

Asset overview

The gas turbine fleet includes two units each across two key compression sites: Rotowaro and Mokau. The Mokau compressor station was established in the 1980s, while the Rotowaro turbines were installed in the late 1990s to supply additional demand for two Auckland located power stations. Some units are now approaching the upper limits of their intended operational lifespan.

Condition and performance

The operational condition of these turbines reflects their age and service history. For instance, routine inspections such as the blade inspection conducted on Rotowaro unit 5 in early 2023 revealed that the high-pressure blades had reached the end of their functional life and were replaced. Other components in this unit are becoming obsolete and are being managed accordingly. This highlights increasing maintenance demands and the eventual consideration for decommissioning older units as they become less viable to operate.

Similarly, Rotowaro unit 6 was found unfit for continued service due to significant wear in the nozzle, high-pressure blades, and combustion chamber. The decision to remove this unit from service was informed by both its deteriorating condition and the limited operational requirement for its output, alongside unjustifiable repair costs.

At Mokau, efforts to extend the useful life and performance of the turbine units have included major overhauls and component replacements. Between 2018 and 2025, both units underwent compressor re-wheeling to enhance discharge pressure capabilities, improve fuel efficiency and meet flow demands. Prior to these upgrades, mismatched compressor curves limited efficiency, but recent interventions have restored optimal operation.

Overall, while the turbine fleet contains both ageing and more recently upgraded units, ongoing condition assessments and upgrades are required to sustain performance. Nevertheless, as turbine components reach or exceed their design life, the need for careful management, replacement, or decommissioning becomes increasingly critical to ensure their reliable and efficient operation.

Table D.12: Condition and performance

Asset	Condition
Turbine engines	The Mokau turbines are currently in good working condition, thanks to the completion of core exchanges that have ensured they remain fit for operational purposes. At Rotowaro, the situation differs between the two turbine units: Unit 6 is no longer considered economical to exchange or upgrade, due to high costs and reduced demand with sufficient redundancy available onsite. For Unit 5, recent inspection has revealed that the hot end is nearing the end of its service life and its operation is being managed to extend its operational lifespan.
Turbine package auxiliary equipment	Whilst the Mokau turbine engines are well maintained with regular 2,000hr and 4,000hr servicing and a 40,000hr replacement of the core; much of the electrical and mechanical items on the package are becoming obsolete. Replacement components must be specified by Solar engineers as failures occur.
Centrifugal compressors	The Mokau centrifugal compressors have been re-wheeled which consists of a complete rebuild process for the compressor. Restoring them to as new condition. At Rotowaro, the Unit 5 compressor is in good condition for operation with recently replaced dry gas seals. The compressor is expected to out-live the turbine engine. The Unit 6 compressor remains in good condition however is unable to be operated due to the condition of the engine.
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 start and stop permissive for each unit. The systems have been updated in an ad-hoc manner and complied with the standards in force at the time. Changes to electrical standards for hazardous areas are a constant challenge as equipment is required to be replaced. The louver system on the Mokau compressors are sticking during testing and needs to be replaced.
Compressor control system support	The programmable logic controllers (PLCs) for the turbine-driven compressors (all compressor sites) are increasingly affected by obsolescence. At Rotowaro, some of the turbine PLC cards and associated turbine PC are now considered obsolete, with limited availability of spare parts and support from the OEM. This presents a growing risk to ongoing reliability and maintainability. Additionally, the vibration monitoring modules used for condition monitoring of the turbines are also obsolete, with replacement parts becoming difficult to source. These modules are critical for early detection of mechanical issues and their obsolescence increases the risk of undetected faults. A programme is underway to manage these obsolescence risks, including the identification of suitable replacement PLCs and vibration modules, and the retention of critical spares where possible. The timing and scope of upgrades will be informed by ongoing condition assessments and operational requirements.
Gas coolers	Gas coolers reduce the temperature of compressed gas to protect downstream equipment and pipeline coatings from heat. Coolers for both the units at Mokau have been re-tubed recently and are in excellent condition. The cooler for Rotowaro unit 5 has some corrosion issues which need to be rectified, and Unit 6 has been removed from service.

Risks and issues

This section outlines the key risks and issues associated with the turbine engine-driven compressor fleet. It summarises the main operational, reliability, and compliance challenges facing these assets. The table below provides an overview of the most significant risks, their potential consequences, and the controls or mitigation strategies in place to manage them.

Table D.13: Risk and issues

Risk and issues	Description
Changing network demand	At Rotowaro, reduced gas demand means turbines are now oversized and often run at light loads, causing increased wear and lower efficiency.
Emissions and efficiency	Older turbine compressor units design lacks modern thermal efficiency and emission reduction technologies, resulting in higher emissions than newer models. Historically, operational procedures and the current regulations didn't prioritise emissions reduction, further exacerbating the issue. We have been reviewing compression pressure setpoint settings and lowering the pipeline operating pressure and running single units where possible to reduce fuel gas consumption and emissions. However, these compressors remain the largest contributor to fleet-wide emissions. Meeting our 30% carbon footprint reduction target by 2030 depends on further upgrades and operational changes.
Security of supply	The security of supply standard requires N+1 redundancy for rotating equipment. In practice this requires complete redundancy for all normally operated compressors. Re-wheeling of the Mokau compressors has brought the two units into equal operation. Only one turbine is required to meet peak demand therefore the N+1 security of supply is achieved. The Rotowaro unit 5 is required only as redundancy to the reciprocating compressors during high loads, therefore N+1 is also achieved despite only having one turbine available. However, Rotowaro unit 5 failed a hot-end inspection, putting N+1 redundancy at risk.
Stranded assets	As operating conditions have evolved, the Rotowaro turbine compressor units are now not required for anything other than contingent operation. As such, only one unit is required, leaving unit 6 surplus to requirements and slated for decommissioning. This reflects the change in operation and the need to right size and optimise the compressor fleet, addressing both reliability and efficiency as network demands shift over time.
Obsolete hazardous area barriers	Many hazardous area electrical barriers on our extra low voltage control system loops are now obsolete requiring scheduled replacement and additional spares to replace upon failure.

Table D.14: Consequences and controls

Threat or issue	Consequence	Controls
Changing network demands	Excessive fuel gas usage; excessive greenhouse emissions; excessive wear. Compressor assets become stranded.	Lower pipeline operating pressure and critical contingency thresholds. Decommission stranded assets. Replace compressors with correct size and lower emissions.
Emissions and efficiency	Excessive fuel gas usage, excessive greenhouse emissions	Right size compression fleet. Lower pipeline operating pressures.
Unit 5 remaining service life.	Loss of N+1 redundancy if Rotowaro unit 5 fails	Maintain contingency plans and limit run time of Rotowaro unit 5 to maintain it as a contingent unit.
Obsolete hazardous area barriers	Failure during operation	Proactive replacement, spares available for reactive replacements.

Lifecycle management

Lifecycle management for gas turbines and centrifugal compressors differs, but both rely on run hours to schedule inspections, maintenance, and renewals. Given the high cost of major components, strategies focus on maximising operating life through a mix of time-based and condition-based maintenance, supported by advanced monitoring.

Gas turbines maintenance

This section summarises maintenance strategies for turbines, compressors, and coolers. It covers key practices such as routine inspections, condition monitoring, and preventative maintenance.

Gas turbines follow a maintenance schedule based on equivalent operating hours, considering starts, running hours, and events like over-firing, with each start-stop cycle and operating hour consuming component life. Traditionally, invasive maintenance was scheduled according to manufacturer guidelines, but these do not always reflect actual operational conditions, as the engines often run at low loads and with clean gas.

Recently, a condition-based maintenance program was implemented at Rotowaro, involving inspections and analysis before replacement. This approach aims to increase maximum engine life to 48,000 fired hours, extending the time between turbine core exchanges and reducing capex. The engines are operated to prevent simultaneous age-related failures.

Routine maintenance includes basic inspections, consumable replacements, inspections and blade sampling. More comprehensive overhauls, life extension inspections, blade sampling, and core exchanges occur at 40,000 or 48,000 hours. The original equipment manufacturer monitors machine performance, material technology development updates and other upgrades; recommending proactive remediation. Overhauls are supervised by the technical authority from the original equipment manufacturer, with hands-on work carried out by local skilled labour and support staff trained overseas. Predictive maintenance strategies such as vibration analysis, temperature, oil analysis, and using borescope inspections are employed to assess the condition of the gas turbine and ensure reliable operation.

Table D.15: Maintenance and inspection activities

Activity	Description	Frequency
Mokau Turbines		
Service	Inlet filter inspection, water washing, visual inspection, and air filter cleaning.	2,000 hours
Service	Inlet filter inspection, water washing, visual inspection, and air filter cleaning. Oil filter change Maintenance checks such as cooler belts Inspect seal gas filters Internal borescope inspection	4,000 hours
I&E checks	Full instrumentation functional checks and calibration	12 months
I&E checks	Partial instrumentation functional checks and calibration	3 months
Vibration monitoring	Vibration analysis	4 months
Major overhaul	Turbine core is exchanged and previous core sent back to manufacturer for analysis.	40,000 hrs
Oil analysis	Oil sample analysis	2 months
Rotowaro turbines		
Service	Water wash, inlet filters changed	2,000 hours
I&E checks	Full instrumentation functional checks and calibration	12 months
I&E checks	Partial instrumentation functional checks and calibration	3 months

Activity	Description	Frequency
Inspection	Internal borescope inspection	12 months
Inspection	Type A basic inspection and replacement of consumables	8,000 hours
Inspection	Inspection and blade sampling	24,000 hours
Major overhaul	Type B + and Type C. Turbine core is exchanged and previous core sent back to manufacturer for analysis.	48,000 hours
Oil analysis	Oil sample analysis	2 months
Vibration monitoring	unit vibration analysis	1 month

Centrifugal compressors

Centrifugal compressors follow an hours-based inspection schedule, with a major (type 3) overhaul typically recommended at 48,000 hours. However, due to lower operational demands, the overhaul is often done closer to 24,000 hours. A condition-based approach now aims to reach the full 48,000 hours between overhauls. The maintenance and inspection activities are detailed below.

Table D.16: Maintenance and inspection activities

Activity	Description	Frequency
Inspection	Visual, seal gas system, valve operation (Type 1)	4,000 hours
Inspection	Vibration monitoring at Rotowaro	1 month
Inspection	Vibration monitoring at Mokau	4 months
Inspection	Visual, alignment and run out, seal gas inspection (Type 2)	12,000 hours
Service	Bearing replacement, gas seal bundle replacement, visual and valve operation (Type 3)	48,000 hours
Oil analysis	Lube oil sample analysis at Mokau	3 months
Oil analysis	Lube oil sample analysis at Rotowaro	12 months
I&E checks	Full instrumentation functional checks and calibration	12 months
I&E checks	Partial instrumentation functional checks and calibration	3 months

Turbine 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 impact 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 allow the cooler to be brought back to specification. The maintenance and inspection activities are shown below.

Table D.17: Maintenance and inspection activities

Activity	Description	Frequency
Inspection	Ground based visual check for obvious damage or leaks	1 month
Inspection	External independent inspection	2 years
Inspection	Independent internal inspection for pressure vessel compliance.	4 years

Renewal

Renewal for the turbine-driven compressor fleet is based on condition, operational hours, and manufacturer guidance. At Mokau, both units are in good condition following recent core exchanges. Unit 2 currently has approximately 21,000 operating hours and may require another core exchange after an additional 8,000–9,000 hours.

At Rotowaro, major servicing is also condition-based and cannot be reliably forecast at this stage. The current strategy is to operate the turbines as contingent units, with no major overhauls planned in the next 10 years. The intention is to manage run hours and asset utilisation until the units are no longer required, particularly as network demand reduces and the station reciprocating compressor upgrade is completed. Dry gas seals are monitored continuously and are replaced on a run-to-failure basis, with no scheduled replacements anticipated in the planning period.

Table D.18: Forecast projects for planning period.

PROJECT NAME	PROJECT DESCRIPTION	EXPECTED PERIOD
Core exchanges	Mokau turbine core exchanges	10 years

Decommissioning

During this planning period, decommissioning is anticipated for Rotowaro unit 6, which is no longer required for N+1 redundancy and is uneconomical to maintain or renew.

Table D.19: Forecast disposals during planning period.

LOCATION	REASON FOR DECOMMISSIONING	UNITS
Rotowaro unit 6	Not required for N +1 redundancy	One unit

D.4.4. Reciprocating engine driven compressors

Asset overview

The reciprocating compressor fleet is both the largest and oldest on our network, responsible for compressing natural gas and maintaining sufficient pipeline operating pressures to meet critical contingency thresholds across the North Island. Comprising 16 units, with two recently removed from service, awaiting decommissioning and two new units coming online at Kaitoke in 2025. Many engines have surpassed their original 30-year design life, and their operational life has been extended via major overhauls. Several units still rely on outdated pneumatic control systems, which complicate instrumentation calibration, fault diagnostics, and lack modern SCADA integration limiting performance analysis.

Condition and performance

The below table provides a summary of the condition and performance of reciprocating engine-driven compressors across our network. The condition of reciprocating compressors generally mirrors that of their associated engines, with newer units in good order and older assets showing varying degrees of wear, obsolescence, or increased maintenance needs. Additional commentary is included on associated systems such as fire and gas detection systems, compressor control systems, and gas coolers.

Table D.20: Condition and performance

Asset	Condition and performance
Reciprocating engines	The engines are in satisfactory condition and major overhauls can extend the operational life of the unit. It is the ancillary equipment that begins to deteriorate or become obsolete, such as manifolds, water pumps, ignition systems and other spare parts; this is exacerbated when engines no longer operate due to reduced demand. While some engines benefited from recent electronic ignition and control system upgrades some older units are still operating with original ignition systems, and these units have recurring faults such as backfires when operating. Due to obsolescence of components and no requirement to operate, several engines are considered uneconomical to maintain and are planned for decommissioning.
Reciprocating compressors	The condition of the reciprocating compressors generally reflects the condition of the associated reciprocating engines at each site. Unit 3 and unit 4 compressors at Kaitoke are new and are in good condition. Compressors at other sites, including Mahoenui, Kapuni, and Rotowaro, are older and have experienced varying degrees of wear, with some units showing signs of heavy use or requiring increased maintenance. Condition across the fleet is mixed and closely linked to the age and maintenance history of each installation.
Fire and gas detection systems	The fire and gas systems are in good condition with recent upgrades on some stations and comply to the standards in force at the time. Ongoing changes to electrical standards for hazardous areas are a constant challenge as equipment is required to be replaced.
Compressor control system support	PLCs are in good condition as the upgrades are recently new, however, PLC components and cards quickly become out of date and obsolete. Backup programs are completed regularly. Several units operate using a pneumatic control system, components are becoming obsolete and in general the control systems are not readily adaptable to changes in control philosophy. Spare PLCs are maintained on a live powered rack to provide readily available configured spares. Historian servers were recently installed in Pokuru, Kaitoke and Mahoenui. Performance and operating data are trended to review performance.
Gas coolers	Gas coolers at Mahoenui and Rotowaro are in poor condition due to external corrosion and poor performance. The gas cooler on Kaitoke unit 2 does not meet its cooling performance. Coolers at Pokuru, and Kapuni are in good condition although the cooler on Pokuru unit 1 does not keep up with engine cooling demands during high loads in summer, requiring the unit to be managed.

Risks and issues

This section outlines the key risks and issues associated with the reciprocating engine-driven compressor fleet. It summarises the main operational, reliability, and compliance challenges facing these assets. The table below provides an overview of the most significant risks, their potential consequences, and the controls or mitigation strategies in place to manage them.

Table D.21: Risks and issues

Risk and issues	Description
Changing network demand	Changes in pipeline operating conditions specifically a decrease in gas demand have rendered some of the existing compressors significantly oversized for their current duty. As a result, these machines operate under light loads, which is unsustainable for long-term use and leads to considerable wear and inefficiency. The sizing cases are made difficult by large swings in network demand and operating requirements which mean that the large compressors are required for some periods and oversized in others.
Emissions and efficiency	Older units lack modern emission controls; new engines at Kaitoke feature electronic management for improved efficiency. Emissions reduction is central to meeting climate targets.
Security of supply	The security of supply standard requires N+1 redundancy for rotating equipment. In practice this requires complete redundancy for all normally operated compressors. While almost all stations have multiple compressors, due to the changes in sizing demands and pressure requirements that have occurred over time, some of the stations require more than a single compressor to be operating at one time to meet the normal demand requirement. Consequently, there are no longer sufficient machines to truly reach a N+1 redundancy

Risk and issues	Description
	requirement of full flow on some sites. Practically, N+1 can be met at a network level, where backup compression between stations provides contingency.
Stranded assets	As operating conditions have evolved, a number of compressor units are now surplus to requirements and are planned for decommissioning. This reflects the change in operation and the need to right size and optimise the compressor fleet, as network demands shift over time.
Ageing equipment	Many reciprocating engine driven compressors are well beyond their original design life. As these assets age, they are more prone to wear, faults, and obsolescence, which can impact operational reliability and increase maintenance requirements.
Obsolete hazardous area barriers	Many hazardous area electrical barriers on our extra low voltage control system loops are now obsolete requiring scheduled replacement and additional spares to replace upon failure.

Table D.22: Consequences and controls

Threat or issue	Consequences	Controls
Oversized compressors	Compressors may become oversized or underutilised, leading to increased wear, reduced efficiency, and risk of asset stranding or inefficient investment.	Regularly review demand and asset use, right-size the fleet, proactively maintain and upgrade equipment, and plan timely decommissioning of surplus units.
Emissions and efficiency	Excess greenhouse gasses emitted; excess fuel gas burnt.	Reduction in pipeline operating pressures where possible; optimising operation of individual machines; Installing modern engine control module systems.
Security of supply	Lack of N+1 redundancy for all flow conditions at Pokuru and Kaitoke;	Installation of additional compression at Kaitoke; Critical redundancy for Pokuru is provided by Rotowaro maintaining N+1 at a network level.
Stranded assets	Unrecoverable capital; ongoing opex for non-operational assets; reduced network flexibility.	Timely decommissioning and disposal; fleet right-sizing.
Aging equipment	Reduced reliability and efficiency	Proactive maintenance; prudent replacement projects for key stations.
Obsolete hazardous area barrier	Failure during operation	Proactive replacement, spares available for reactive replacements.

Lifecycle management

Reciprocating engines maintenance

Reciprocating engines are maintained through scheduled inspections and services at operating hour intervals, proactive monitoring (including vibration analysis and oil sampling), and major overhauls based on equipment condition and performance data. A combination of in-house and specialist support ensures all maintenance, from routine tasks to full overhauls.

The following table outlines the maintenance and inspection activities performed.

Table D.23: Maintenance and inspection activities

Activity	Description	Frequency
Vibration analysis	Vibration monitoring at Rotowaro	1 month
Check	Oil sample analysis	2 months
Vibration analysis	Vibration monitoring at Pokuru	3 months
Vibration analysis	Vibration monitoring at Kaitoke	4 months

Activity	Description	Frequency
I&E checks	Partial instrumentation checks and calibration	6 months
I&E checks	Full instrumentation checks and calibration	12 months
Servicing	Change oil and filters, clean strainer, check mag-plugs. Check valve recession, adjust valve clearances. Inspect coils and leads, replace plugs. Replace air filter elements. Inspect governor assembly. Check and replace as required Aux and Main water pump belts. Check cooler assembly, grease pillow blocks. Top up starter lubricator oils. Running checks and tune as required.	2,000 hours
Servicing	All above items and inspect magnetos and change coupling. Replace aux and main water pump belts. Disassemble carburettors, replace diaphragms and check fuel cones. Remove all pan doors and replace seals. Inspect oil pump and pickup screen, Measure web deflection. Borescope of all cylinders. Inspect governor assembly and linkages and grease.	8,000 hours
Overhaul	Cylinder head and turbo replacement	24,000 hours
Overhaul	Major overhaul	70,000 or condition based

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 D.24: Maintenance and inspection activities

Activity	Description	Frequency
Vibration analysis	Vibration monitoring at Rotowaro	1-4 months
I&E checks	Partial instrumentation functional checks and calibration	6 months
I&E checks	Full instrumentation functional checks and calibration	12 months
Servicing	Oil change, filters. Carry out as found measurements – cross heads, rod run outs, crank case inspection. Change force feed lubrication oil. Running checks	4,000 hours
Servicing	Oil change, filters. Replace suction and discharge valves. Replace packing cases. Carry out as found measurements – cross heads, rod run outs, cylinder measurements, piston and rod checks, bearing checks, crank case inspection – replace all parts as required determined by OEM limits. Change force feed lubrication oil. Carry out alignment. Running checks.	8,000 hours
Servicing	All above items + remove crosshead pins check bore clearances and pins and replace as required. Check end drive chain tensioner bushing and replace if required.	16,000 hours
Servicing	All above items + replace lubricator blocks, replace cross head connecting rod bushings.	32,000 hours

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 activities are shown below.

Firstgas

Table D.25: Maintenance and inspection activities

Activity	Activity	Frequency
Inspection	Ground based visual check for obvious damage or leaks	1 month
Inspection	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	6 months
Inspection	External independent inspection	2 years
Inspection	Independent internal inspection for pressure vessel compliance.	4 years

Renewal

The following table outlines the expected renewal projects for the reciprocating engine driven compressor fleet over the planning period.

Table D.26: Forecast projects for planning period.

Project	Details	completion period
Rotowaro compressor replacement	Rotowaro compressor unit rightsizing and age replacement	4 years
Southern network reinforcement	Kaitoke compressor station redundancy improvement	4 years
Routine refurbishments	Compressors and engine are required to be rebuilt to extend operating life	10 years

Decommissioning

During this planning period, we plan to decommission four reciprocating engine-driven compressor units.

Table D.27: Forecast disposal projects for planning period.

Location	Reason for decommissioning	Units
Kapuni	Kapuni unit 5 has reached its maximum operating life, with minimal spares available to extend life, meet current emissions requirements and uneconomical to renew	1 unit
Mahoenui	The 200 line no longer requires 3 units to maintain operations and redundancy. Unit 3 has been selected to be decommissioned due to its current condition	1 unit
Kawerau	Compression has not been required at Kawerau for some time. Compression was maintained in case a new supply contract was required in Gisborne. This is no longer feasible, and the units will be decommissioned.	2 units

D.4.5. Electric driven compressors

Asset overview

Two electric motors paired with reciprocating compressors were installed at Henderson to support gas delivery pressure for the Marsden Point refinery. Since the refinery's closure, this additional gas supply is no longer required. The Henderson compressor fleet, being among the newest in our network, remains in very good condition. As we continue to adapt our network configuration, we anticipate commencing compressor operations at Henderson to bolster pressure capacity for Northland. This will enable us to reduce reliance on over-compression at Rotowaro, optimising the overall efficiency and balance of our compression network.

Firstgas

Condition and performance

This section provides a summary of the current state of electrically driven compressors and their supporting systems at Henderson. It highlights key aspects such as asset age, operational status, integration with monitoring and control systems, and the approach to ongoing maintenance and compliance. The following table presents site-specific observations and supporting information.

Table D.28: Condition and performance

Asset	Condition and performance
Reciprocating compressors	The reciprocating compressors at Henderson are among the newest in the network, having seen minimal operational hours since installation. They remain in excellent mechanical condition, with no significant wear or reliability concerns reported. All major components, including cylinders, valves, and packing, are within manufacturer tolerances. The compressors are equipped with modern instrumentation and are fully integrated with the site's SCADA and performance monitoring systems. Routine inspections confirm that vibration, temperature, and lubrication parameters are stable and within expected ranges.
Electric motors	The electric motors at Henderson compressor station are modern, high-capacity units installed as part of the site's recent upgrade. They have seen minimal operational hours since commissioning and remain in excellent condition, with no significant wear, overheating, or vibration issues reported. Preventive maintenance, including annual inspections of windings, bearings, and vibration logs, has not identified any faults. The motors are fully integrated with the site's SCADA and performance monitoring systems, and no major overhauls or renewal works are anticipated in the next 10 years.
Fire and gas detection systems	The fire and gas detection systems are in good operating condition.
Compressor control systems	The current control system is relatively new and in good condition. Like all electronic control systems, obsolescence will need to be monitored.
Gas coolers	The gas coolers at Henderson are the same age as the compressors and are in good condition. Ongoing condition monitoring and routine maintenance are in place to address any emerging issues.

Risks and issues

This section outlines the key risks and issues associated with the electrically driven compressor fleet. It summarises the main operational, reliability, and compliance challenges facing these assets. The table below provides an overview of the most significant risks, their potential consequences, and the controls or mitigation strategies in place to manage them.

Table D.29: Risk and issues

Risk and issues	Description
Stranded asset threat	If loads continue to decline, Henderson units may become surplus to requirements.

Table D.30: Consequences and controls

Threat or issue	Consequence	Controls
Single source electricity supply	Loss of compression during a power outage.	Ability to provide compression from Rotowaro CS. Temporary generator can be installed if needed during longer term outages.
Stranded asset threat	Henderson may become surplus to requirements if northern loads continue to decline.	Monitor network demand and review compressor utilisation regularly; plan for decommissioning or repurposing if required.

Maintenance of electric drive for compressors

Maintenance and inspection activities for electric motors that drive compressors are shown in the below table.

Table D.31: Maintenance and inspection activities

ACTIVITY	DESCRIPTION	FREQUENCY
Inspection	Vibration monitoring	2 months
I&E checks	Partial instrumentation functional checks and calibration	6 months
Inspection	Electric motor and variable speed drive checks Bearing oil, windings, vibration, VSD logs and filter cleaning	12 months
I&E checks	Full instrumentation functional checks and calibration	12 months
Servicing	Replacing compressor oil & filters	4,000 hours

Maintenance of reciprocating compressors

The key maintenance and inspection activities for electrically driven reciprocating compressors are shown below.

Table D.32: Maintenance and inspection activities

ACTIVITY	DESCRIPTION	FREQUENCY
Inspection	Vibration monitoring	2 months
I&E checks	Partial instrumentation functional checks and calibration	6 months
I&E checks	Full instrumentation functional checks and calibration	12 months
Servicing	Oil change, filters. Carry out as found measurements – cross heads, rod run outs, crank case inspection. Change force feed lubrication oil. Running checks	4,000 hours
Servicing	Oil change, filters. Replace suction and discharge valves. Replace packing cases. Carry out as found measurements – cross heads, rod run outs, cylinder measurements, piston and rod checks, bearing checks, crank case inspection – replace all parts as required determined by OEM limits. Change force feed lubrication oil. Carry out alignment. Running checks.	8,000 hours
Servicing	All above items and remove crosshead pins check bore clearances and pins and replace as required. Check end drive chain tensioner bushing and replace if required.	16,000 hours
Servicing	All above items + replace lubricator blocks, replace cross head connecting rod bushings.	32,000 hours

Maintenance of 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 activities are shown below.

Table D.33: Maintenance and inspection activities.

Activity	Description	Frequency
Inspection	Ground based visual check for obvious damage or leaks	1 month
Inspection	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	6 months
Inspection	External independent inspection	2 years
Inspection	Independent internal inspection for pressure vessel compliance	4 years

Renewal

No major renewal works or overhauls are anticipated for the Henderson compressor station within the next 10 years. All major equipment, including compressors, electric motors, control systems, and gas coolers, are currently assessed to be in good condition, and significant intervention is not expected in the current planning period.

Decommissioning

No decommissioning is currently planned for the Henderson compressor station. However, if network demand in the northern region continues to decline and the station becomes surplus to requirements, a disposal or decommissioning plan may be developed in the future.

D.5. SCADA and communications

D.5.1. Asset overview

The SCADA (supervisory control and data acquisition) system is fundamental to the operation of the gas transmission network, enabling real-time monitoring, control, and metering of gas flow across the network. Operating continuously, SCADA collects vital data from remote sites and equipment, transmits it to a central control room, and allows operators to manage supply, balance demand, and ensure overall system safety and efficiency.

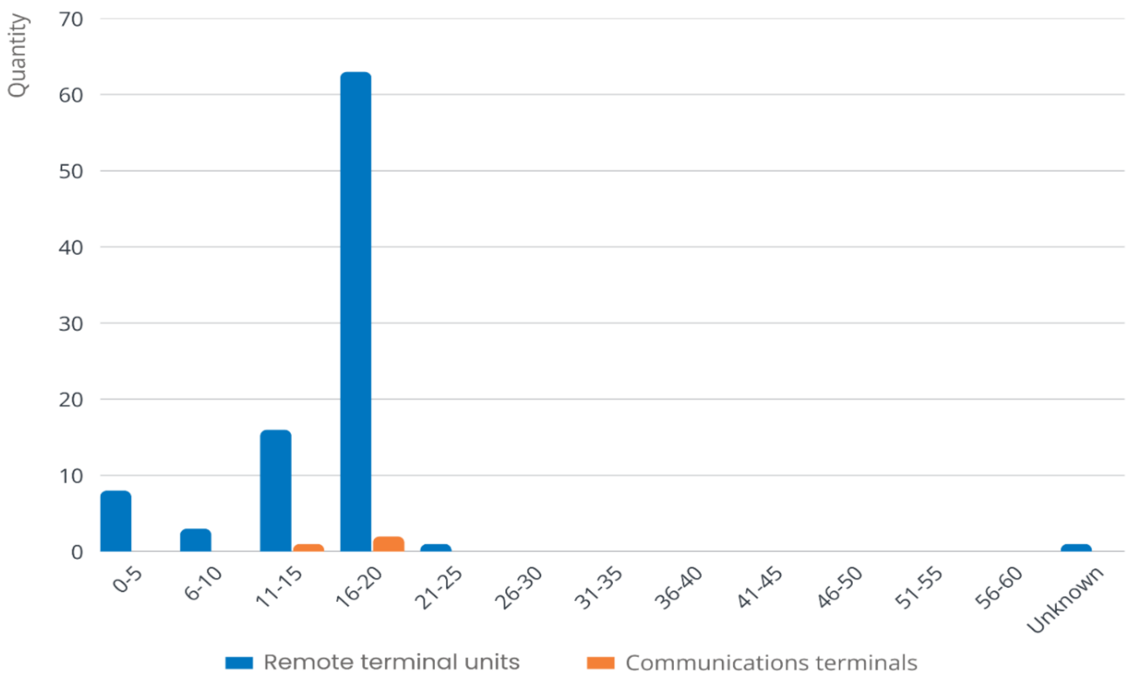
At its core, the SCADA system is comprised of several key components.

- **Remote terminal units:** These devices are installed at various sites along the pipeline. Remote terminal units gather data such as pressure, flow, composition and temperature, and relay this information back to the control room. They can also receive commands from operators to remotely start/stop compressors and adjust pipeline pressure setpoints.
- **Communication links:** Data from remote terminal units and programmable logic controllers is sent to the main control room via a range of communication methods, including physical cables and cellular networks.
- **SCADA master terminal:** This central system collects and organises all incoming data from remote devices, presents it to operators for oversight, stores it for analysis, and shares it with other business systems. The system is designed for high availability, with both a primary master terminal and a disaster recovery backup to ensure continuity.
- **Historians:** These are specialised data storage systems that archive large volumes of operational information, making it accessible for future analysis or compliance reporting.

D.5.2. Age profile

The age profile indicates that a significant number of our remote terminal units (RTUs) and our communication terminals have been in service for many years and are now approaching the end of their operational lifespan. To maintain reliability and prevent potential failures, these units will require replacement. The below graph shows the age profile of our remote terminal unit and communication terminals.

Figure D.5: Remote terminal unit and communication terminals age profile



D.5.3. Condition and performance

The master SCADA system is being replaced to address support and obsolescence issues. Many RTUs and communication terminals are reaching the end of their service life, mainly due to technological changes and lack of vendor support. The phase-out of networks, such as 2G/3G cellular and copper phone lines, has accelerated equipment obsolescence and caused compatibility challenges, prompting the need for upgrades.

D.5.4. Risks and issues

This section outlines the key risks and issues associated with the SCADA and communication fleet. It summarises the main operational, reliability, and compliance challenges facing these assets. The table below provides an overview of the most significant risks, their potential consequences, and the controls or mitigation strategies in place to manage them

Table D.34: Risk and issues.

THREAT OR ISSUE	CONSEQUENCE	CONTROLS
Network communication changes. (2G/3G, copper phone lines)	Communication between site and control room are not supported.	Updated asset lifecycle replacement.
Cyber security threats.	Plant not able to be monitored, equipment controlled by others, ransom.	Active cyber security program. Updating hardware and software.
Obsolescence	Lack of vendor support, spares and unsupported software.	Proactive procurement and managing supplier relationships

Threat or issue	Consequence	Controls
Legacy platforms & architecture	The inherent design of many of our systems is based on outdated designs, resulting in higher ongoing costs or limited abilities	Replacement and upgrade programmes include updated architecture and specifications to reflect modern standards
Data access/remote access	Increasing demands for wider business access to data or remote access to systems, limiting and/or slowing decision making and cyber security risks.	Strategy developed to enable simplified data access and availability and secure remote access solution.

D.5.5. Lifecycle management

Maintenance

We maintain a proactive maintenance programme, with all activities scheduled and tracked in Maximo. The majority of maintenance tasks are handled by our internal technicians, although we engage specialist contractors when necessary.

Each remote site is visited every two years to complete maintenance activities. In addition, our local technicians perform annual point-to-point checks of analogue and digital inputs and outputs, as well as uninterruptible power supply testing. Monthly meter readings are also conducted to ensure system accuracy.

At our control room, we have a programmed maintenance schedule for the testing of disaster recovery processes, uninterruptible power supply systems, and master system backups.

We continue to collaborate with communication service providers to transition remote stations to suitable communication solutions for the location, which will support future maintainability and alignment with technological developments. SCADA and communications equipment consist of several components, and their maintenance requirements are addressed through the activities outlined below.

Table D.35: Maintenance and inspection activities

Activity	Description	Frequency
Master system routine checks	System performance checks. Communication reliability checks.	Weekly
Master system routine checks	History archiving checks. System back-up initiated. Disaster recovery update. Production and disaster recovery system alignment Vendor patch updates	1 month
Meter data validation	Site meter readings and verification of data	1 month
Master system routine checks	Wireless probe System log checks System security checks	3 months
Onsite inspection and calibration	Site to control room end to end point checks. Uninterruptible power supply testing.	12 months
Onsite maintenance and inspection	Remote terminal unit full calibration, battery replacement. Site back up power supply testing and electrical equipment inspection.	2 years

Renewal

Renewal for SCADA systems, remote terminal units and all forms of communications equipment is primarily driven by the necessity to update hardware and software to align with evolving industry standards. As technology advances, existing equipment is inevitably superseded, rendered obsolete, and ultimately no longer supported by manufacturers. This cycle of obsolescence is largely beyond our control, making proactive replacements essential to guarantee ongoing technical support and reliable system operation.

Table D.36: Forecast projects for planning period.

PROJECT NAME	PROJECT DESCRIPTION	COMPLETION PERIOD
SCADA master system replacement.	Replacement of SCADA master system including historian upgrade.	3 months
SCADA master system optimisation.	Project to optimise the SCADA master system and data historian.	12 months
Site communication upgrades.	Replacement of onsite communication and monitoring equipment to latest technology requirements. (sites without flow computers)	12 months
Remote terminal units and flow computer replacements.	Replacement of onsite remote terminal units and flow computers with a single unit.	4 years
Control room lifecycle replacements.	Lifecycle management replacement of control room electronic equipment/	4 years
Onsite lifecycle replacements.	Ongoing replacement of equipment on stations for the operation and communication between onsite equipment and the master stations	10 years
Cyber security hardening	Ongoing reinforcement of network systems against cyber security threats.	10 years
SCADA master system update	Routine master system updates	10 years

D.6. Other stations

Other stations encompass a diverse range of assets installed above-ground at our sites. These assets serve critical roles such as regulating and maintaining network pressure, providing downstream pipeline protection, housing dry gas filters for particulate removal, and enabling routine pipeline cleaning as well as advanced in-line inspection activities. These components ensure that the gas transmission network operates reliably and safely from intake to delivery.

D.6.1. Pigging facilities

Asset overview

Pig launchers and receivers (collectively known as pig traps) facilitate the use of in-line inspection (ILI) and internal cleaning tools. Pig receivers also act to contain and facilitate safe disposal of debris which is removed from the pipeline by cleaning tools.

Pig traps are typically installed during pipeline construction; however, some of our pipelines did not originally include pigging facilities. Projects have since been devoted to upgrading these systems to enable ILI on pipelines that previously could not be pigged. Pig traps are installed across many of our stations. They contain launching or receiving barrel incorporating quick-release enclosure doors, kicker lines, valves and pipework to equalise pressure and vent the pig trap.

ILI tools have evolved to support new technologies and smaller pipelines, resulting in longer designs to facilitate multi-tooling in-line inspection tools and to reduce the need for multiple runs. A survey report highlighted the need to modify pig traps for these new tools. Standard portable pig traps were deemed impractical because station layouts varied and modifications would be costly. Both new and existing traps have been updated to incorporate best practices for safe tool launching and receiving.

Condition and performance

Pig traps are in excellent condition, following a comprehensive programme focused on modifications and upgrades to support the latest ILI tools and stringent maintenance standards. Protective coatings are well maintained, and any signs of corrosion are promptly addressed to prevent deterioration. In instances where older valves have failed to seal effectively, valves have been either replaced, or supplementary valves have been installed; these areas are safely managed using double block and bleed procedures to ensure continued integrity and operational safety of the pig traps.

Risks and issues

Risks related to pig traps often stem from their ancillary equipment. We aim to reduce these risks by updating procedural controls, adjusting maintenance plans, and replacing assets.

Table D.37: Risk and issues

Threat or issue	Consequence	Controls
Coating deterioration and pipe support corrosion.	The interface between pig trap and pipeline supports can cause hidden corrosion between connecting metal points, leading to loss of wall thickness and pressure integrity.	Coating and pipe support are inspected on a two yearly frequency. Latest pipe supports designs incorporates corrosion prevention attachments to minimise water retention.
Leaking door seals	Gas leaking to atmosphere, increased emissions, loss of gas and gas atmosphere.	Routine leak testing, inspection and replacement of door seals.
Older ball valves with diminished isolation capability.	Pipeline pressure not isolated from pig trap. Risk of gas atmosphere and pressure causing sudden pig displacement.	Replace with new valves, install double block and bleed systems; isolation integrity checks.
ILI tool designs	Pig traps need to be replaced to accommodate longer newer ILI tools.	Replace non-conforming pig traps.

Lifecycle management

Maintenance

Pig trap maintenance is governed by our pressure equipment management plan. An external qualified inspector is required for any pig trap with a nominal bore greater than 150 mm, while other activities are performed by in-house competent technicians.

Pig trap maintenance and inspection requirements are summarised below.

Table D.38: Maintenance and inspection activities

Description	Frequency
External coating inspection	2 years
External inspection DN100mm pipeline or smaller	2 years
External inspection and certification of DN150mm pipeline or larger by qualified vessel inspector	2 years

DESCRIPTION	FREQUENCY
Internal inspection DN150mm pipeline or larger and certification by qualified vessel inspector	4 years
Door seal inspection and replacement	2 years
Valve tightness tests	2 years

Renewal

Renewal activities stem from requirements to install new pig traps on pipelines that were previously unsuitable for pigging, as well as by advancements in in-line inspection tool designs and the integration of additional sensors, factors that are generally outside our direct control. Pig traps are updated to accommodate the latest equipment provided by specialist pigging vendors. Renewal may also involve the replacement or installation of additional valves to ensure proper isolation. Below we set out a summary of renewal projects associated with pig traps.

Table D.39: Forecast projects for the planning period.

PROJECT NAME	DESCRIPTION	COMPLETION PERIOD
504 Rotorua Taupo Offtake to Reporoa	Upgrading receivers and launcher to make pipeline piggable	4 years
702 Foley Road	Upgrading receivers and launcher to make pipeline piggable	4 years
434 Whangarei lateral	Upgrading receivers and launcher to make pipeline piggable	4 years
435 Kauri lateral	Upgrading receivers and launcher to make pipeline piggable	4 years
421 Te Awamutu North lateral	Upgrading receivers and launcher to make pipeline piggable	4 years

D.6.2. Pressure regulators

Asset overview

Pressure regulators are used to lower gas pressure to desired levels to supply gas directly to customers, into distribution networks, or further along transmission pipelines. Various models exist to meet different capacity and flow requirements, ranging from simple spring-and-diaphragm types to advanced electronic or pneumatically controlled valves.

These devices separate networks and pipelines with different maximum allowable operating pressure levels, reducing the risk of over-pressurisation. A typical regulator design at our stations features four regulators arranged across two parallel streams. Each stream includes an operating regulator (referred to as the worker) and a backup regulator (the monitor). The monitor is set to a slightly higher pressure, ready to take over if the worker fails, thereby ensuring backup capability. In the standby stream, the operating regulator remains closed due to a lower setpoint, with its own monitor as backup. Should the main stream's worker regulator close and system pressure drop, the standby stream activates, supplying gas at a marginally lower pressure to maintain continuous service. This configuration, using monitors and standby streams, provides reliable, uninterrupted supply and allows for maintenance without service disruption.

Safety standards require secondary protection measures, which might include monitor regulators, slam-shut valves, or pressure safety valves.

Condition and performance

The current fleet of pressure regulators is in good condition, thanks to work programs over the past decade that have systematically replaced equipment approaching end of life. Regulator coatings are maintained in conjunction with station pipe inspections, effectively preventing deterioration from corrosion.

Regulator reliability is evaluated on their ability to maintain the specified flow at a steady delivery pressure, minimising pressure droop at high flow and the regulator passing downstream at zero flow. Changes in demand conditions can affect whether a regulator continues to meet performance requirements. Regulator reliability is assessed through the rate and impact of failures. A regulator considered reliable typically does not require frequent adjustment, functions under varying environmental and gas conditions, and demonstrates infrequent or minor failures.

Risks and issues

Risks associated with regulators primarily stem from the potential for over- or under-pressure within the downstream network they supply, which can compromise pressure integrity and service reliability. To mitigate these risks, maintenance activities are designed to prevent failures and ensure that safety features function as intended. Timely procurement of additional spare parts and planned replacement means reaching end of useful life rarely poses a significant risk.

Regulators are exposed to contamination from substances present within the natural gas stream. Such contamination can adversely affect regulator materials, with soft components at risk of swelling or deterioration, while accumulated solids may cause blockages that impede flow and reduce downstream pressure. To address this, several mitigation strategies have been implemented: specialist filters have been installed to trap particulates or remove specific substances before they reach sensitive components; new pilot control valves and pressure setup designs help maintain stable operation; and heat tracing has been applied to the tubing supplying pilot and pressure regulators, reducing the risk of liquid drop out and associated blockages. A proactive inspection and cleaning program is undertaken, ensuring contaminants are identified and removed early, mitigating the risk of malfunction and supporting ongoing system reliability.

Table D.40: Risks and issues

Threat or issue	Consequence	Controls
Regulator is obsolete (no longer manufactured and parts unavailable)	Regulator cannot remain in service due to lack of spare parts	Monitor availability of replacement parts; replace regulator before parts are unavailable
Contamination build-up in regulator or pilot operating valves.	Performance may be impacted resulting in failure to stand by stream.	Regular inspection and maintenance. Where possible, specific filters, heat tracing and pilot designs.
Regulator failure	Downstream over or under pressure.	Pressure relief valves, shut off valves, back up regulators, routine functional checks.
Changing network demand	Regulators could become oversized, not controlling the pressure adequately in the downstream network.	Annual review of network demand and pressure control. Proactive replacement of regulators with the correct size.

Lifecycle management

Maintenance

We implement a proactive maintenance program for all our pressure regulators, regularly testing their functionality and inspecting for any signs of contamination. A summary of these activities is provided in the following table.

Table D.41: Pressure regulator maintenance and inspection activities

Activity	Frequency
Gorter/Honeywell regulator contamination checks	1-3 months
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	6 months
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	12 months
Overhaul regulator valve, overhaul pilot valve, overhaul control valve	As required
Gorter/Honeywell regulator and pilot major overhauls	5 years

Renewal

Regulator replacement is not based on age; many units operate beyond their design life if parts are available and performance remains adequate. Replacement decisions are based on reliability, maintainability, performance, and obsolescence. Obsolete or soon-to-be obsolete regulators are phased out.

No major regulator projects are planned. However, a few regulators are out of production, though spare parts remain available. If this changes during the planning period, we will need to schedule replacements.

Table D.42: Forecast projects for the planning period.

Project name	Description	Completion period
Regulator replacements	Big Joe regulator obsolescence replacements possible.	10 years

Disposal

The plan includes the disposal of two stations, and an evaluation of stations considered uneconomical, which may result in their decommissioning or disposal during the planning period. These stations consist of pressure regulators and related equipment, including heating and metering systems.

We are currently forecasting an increase in opex to accommodate these activities.

Table D.43: Forecast disposal projects.

Project Name	Description	Completion period
Decommission Alfriston delivery point	Sole large user has ceased operation. Reduce and isolate pressure to delivery point, leave in a safe suspended state.	4 years
Decommission Mangatainoka delivery point	Sole large user has ceased operation. Reduce and isolate pressure to delivery point, leave in a safe suspended state.	4 years
Remove oversized equipment Marsden delivery point	Sole large user has ceased operation. Equipment is now oversized and expensive to maintain for smaller supply.	10 years
Uneconomical stations	Investigate and plan the decommissioning or disposal or uneconomical stations such as delivery points.	10 years

D.6.3. Pressure relief valves

Asset overview

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 network. 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/NZS 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/NZS 2885 for a secondary pressure limiting device such as a pressure relief valve, to be installed.

Condition and performance

At present, the overall fleet is in satisfactory condition, with no concerns about reliability or obsolescence. Regular testing during scheduled maintenance assesses reliability and performance. Relief valve performance is measured by the ability of the valve to operate and reseat at its setpoint, preventing inadvertent operation or over pressure of downstream equipment. Occasionally, valves may 'chatter' due to rapid cycling of the valve when testing; if this becomes severe, it can lead to failure to reseat properly or cause internal damage.

Risks and issues

The primary concern associated with relief valves is their potential failure to operate as intended, which compromises the over-pressure protection of equipment or downstream networks. To address this, all relief valves are managed in alignment with our pressure equipment management plan. This plan ensures that relief valves are subject to preventive maintenance schedules and inspection. Through these proactive measures, we aim to mitigate risks associated with valve malfunction.

Table D.44: Risk and issues

RISK OR ISSUE	CONSEQUENCE	CONTROLS
Failure to operate	Over pressure of equipment and networks	Routine testing and overhaul
Stuck shut	Relief valve fails to operate before 110% of setpoint	Relief valve is repaired or replaced and re-tested; interval to next inspection is reduced
Noise	Public reports of noise	Installation of appropriately sized vents, or relief replaced with other form of protection
Emissions	Relief valve releases natural gas to air on operation or testing	Testing intervals are set based on relief reliability, and alternative protection is used when suitable

Lifecycle management

Maintenance

Maintenance of pressure relief valves includes internal procedures and external certification. This split exists because certain relief valves require certification under our pressure equipment management plan, as well as compliance with AS/NZS 3788 standards, which specify that relief valves protecting specific equipment must be certified by independent, qualified parties.

Maintenance frequency is outlined within the pressure equipment management plan. Complementing this, a separate document prescribes the required testing protocols to be followed by our technicians. During each maintenance cycle, thorough data gathering supports the evaluation of valve reliability and confirms continued correct operation.

This approach enables us to track performance, address potential issues proactively, and maintain the integrity of the pressure relief systems. Through a combination of scheduled in-house maintenance and mandatory external audits, we ensure that relief valves meet stringent safety standards and regulatory requirements.

The following table is a summary of our maintenance and inspection activities for relief valves.

Table D.45: Maintenance and inspection activities

Activity	Description	Frequency
Visual inspection	External inspection for corrosion and leaks.	12 months
Certified testing and inspection	Relief valves protecting specific pressure equipment such as vessels and coolers are required to be tested, overhauled and certified by qualified third party test agencies. Frequency is determined by relief valve service and repeatability of function testing.	12 months to 5 years
Noncertified testing and inspection	Relief valves that are not required to be certified are tested by qualified technicians using established procedures. Frequency is determined by relief valve service and repeatability of function testing. Maintenance includes function testing, PSV operation checks, corrosion inspection, and leak testing.	6 months to 5 years
Routine refurbishment (overhaul)	Overhaul relief valve and pilot assembly with new parts, retest and install.	4-5 years

Renewal

Relief valves are planned for replacement as spare parts become discontinued. They are replaced if soft parts are unavailable or if their reliability and performance fall short of acceptance test criteria.

Table D.46: Forecast projects for planning period.

Project Name	Description	completion period.
Inglewood relief valve replacement	Replace existing reliefs with larger capacity relief valves.	4 years

D.6.4. Isolation valves

Asset overview

Isolation valves segregate sections of station pipework, instrumentation tubing, equipment, or pneumatic control systems, enabling work on the assets and facilitating emergency shutdowns. Across the network, there are over 8,000 valves in use. The types of isolation valves include ball valves, gate valves, plug valves, globe valves, and needle valves, each designed for accessibility and ease of operation. All stations have isolation valves; some allow remote control via our SCADA system.

Isolation valves are primarily installed above ground. Typically, they are operated manually via a lever or rotary hand wheel connected through a gearbox; however, certain valves are actuated and may be controlled by electric motors or pneumatic gas actuators. Below ground variants are operated using a purpose-built valve key or an above ground extension with a hand wheel. Connections to pipeline systems are achieved through bolted flanges, welded joints, or a combination, with smaller valves sometimes using threaded connections.

Condition and performance

Our fleet of valves is in satisfactory condition, with a central register in place to record valves that perform poorly during isolations or are known to leak to atmosphere. The majority of our valves were installed during initial construction and continue to perform adequately, but many older valves have some loss of sealing capability which is being monitored and managed. Because seals are almost exclusively made of soft elastomeric materials, damage and deterioration over decades of use is inevitable and the prevalence of issues with the older valves in the fleet will continue.

Risks and issues

The primary risks and issues related to our isolation valves include challenges with sealing performance, external corrosion, operational difficulties, and containment failures, usually at the stem seal. Over time, valves may lose their ability to form a tight seal, increasing the risk of gas leakage during isolations. External corrosion further compromises the structural integrity of the valve, while some units can become stiff or seize, impacting operation.

Replacing problematic valves can be complicated, especially when it involves stopple fittings or cutting welded joints to isolate sections of live pipelines, whilst maintaining supply to customers. These complex replacements require significant planning and engineering support. Additionally, many of the installed Bettis actuators are becoming uneconomic to maintain due to the need for major refurbishments and the lengthy lead times for obtaining soft parts. The supply of overhaul kits is expected to discontinue in the coming years.

Table D.47: Risk and issues

Risk or issue	Consequence	Controls
Sealing performance	Increased risk of gas leakage under isolation and downstream pressure increasing.	Timely and prioritised replacement or repair of faulty valves. Double block and bleed. Routine testing.
External corrosion	Compromised structural integrity of the valve.	Coating inspection and maintenance. Replacement of corroded valves.
Stiff to operate	Valves may become stiff or seize, making operation difficult or impossible.	Regular operation checks and maintenance; replace seized valves
Valve replacement complexity	Live pipeline welding and bypasses requiring increased engineering, projects and operation resources.	Advance planning and engineering support for complex replacements
Bettis actuator obsolescence.	Becoming uneconomic to maintain; risk of actuator failure	Prioritise replacement with maintainable actuators; plan for obsolescence

Lifecycle management

Maintenance

Valves used for maintenance and isolation are operated frequently to confirm both the valve and gearbox function as intended. However, some valves cannot routinely be cycled to their closed position due to their position within the supply stream, where closing them could disrupt service to customers. These valves are typically not exercised unless there is an emergency situation. In such cases, additional upstream valves are available to provide further isolation if required. Isolation valves maintenance and inspection is summarised below.

Table D.48: Maintenance and inspection activities

Activity	Frequency
Operate valve, verify actuator operation and limit, lubricate if required, check seat tightness and leak check	12 months
Coating condition inspection and cleaning if required	2 years
Overhaul actuator	Condition based

Renewal

Valves are generally expected to function throughout the lifespan of associated assets; however, replacement becomes necessary when they can no longer be actuated, begin leaking to atmosphere, or passing under isolation. Replacement is also favoured when repair costs exceed those of installing a new valve or actuator.

The decision to replace a faulty valve is primarily driven by risk assessment, with higher-risk issues receiving priority. Where possible, valve replacements are coordinated with other scheduled activities on site to optimise efficiency and minimise operational disruption. The complexity of each replacement and its cost, depend on factors such as the need for pipeline or station isolation, live pipeline work and resources required.

As valves age, ongoing reactive replacements are expected throughout the planning period.

Table D.49: Forecast projects for planning period.

Project Name	Description	Completion Period
Horotiu faulty valve replacements	2 valves require replacement due to minor stem leaks during operation.	12 months
Longburn offtake valve replacements	3 valves onsite require replacement due to inadequate sealing during isolation testing.	4 years
Foxton DP isolation valves passing	5 Isolation Valves on Regulator Streams Passing under isolation and are being planned for replacement.	4 years
RIR 5849 Inglewood delivery point valve replacements	HV-11908 is very difficult to operate and requires replacement.	4 years
Bettis actuator replacements	Bettis actuator spare parts may become unavailable in the planning period.	10 years

D.6.5. Filters

Asset overview

Dry gas filters are essential to remove solid particulate contamination from the gas stream, protecting downstream assets from erosion, blockage, and other forms of damage. Filters are incorporated at multiple points across the network. These include small instrumentation filters that protect sensitive measurement and control equipment, station inlet pipework filters positioned at gas inlet points to ensure gas is clean before entering pressure regulator and metering systems, and large filter vessels installed upstream of compressors to remove particulate matter before compression.

Dry gas filters play an important role in meeting the requirements of NZS 5442 - Specification for Reticulated Gas. By removing contaminants, they help ensure that gas delivered throughout the network remains within mandated gas specification standard.

Condition and performance

In general, filters are not subject to significant deterioration if external corrosion is prevented. Non-destructive testing of large filter vessels sometimes reveals material anomalies which require remediation.

The current filter fleet is in good working order and continues to meet the operational requirements of the network. Regular coating inspections are conducted to detect and prevent external corrosion. Large filter vessels are subject to inspections in accordance with our pressure equipment management plan and the requirements of AS/NZS 3788:2006 standards.

Risks and issues

Risks associated with filters are generally linked to the condition of their external coatings. Occasionally, non-destructive testing during filter vessel certification may reveal minor anomalies; these are typically insignificant and do not raise concerns regarding the integrity of the filters. Many of these filters have been in service since construction and were not designed for quick opening or quick replacement of internal filter elements, resulting in increased maintenance time. Additionally, some older elements utilise cloth filters which, while still functioning correctly, would not be chosen for installations today. Retrofitting filters into existing stations can be costly, so wherever feasible, alternative solutions are implemented to avoid the expense of full retrofits.

Table D.50: Risk and issues

THREAT OR ISSUE	CONSEQUENCE	CONTROLS
Obsolescence	Filter element spares are no longer available.	Proactive replacements or sourcing of aftermarket elements.
Blockages	Reduced gas flow/pressure or damage to filter elements and passage of particulates to downstream system	Some networks contain n-1 redundancy or pressure gauges for monitoring. Regular inspection and replacement of filter elements. Use supplementary filtration during pipeline pigging operations.
Performance of “bag” or “sock” style filters below current performance standards.	Excessive passage of particulates into downstream equipment and pipework	Filters will be replaced with conventional cartridge/element type filters. 2 year filter inspection, routine regulator and metering inspections.

Lifecycle management

Maintenance

Filters regardless of size largely require little maintenance and is summarised below.

Table D.51: Maintenance and inspection activities

Activity	Frequency
Inspect and replace element if necessary	2 years
Coating and corrosion inspection	2 years
Filter vessels external inspection by qualified inspector	2 years
Filter vessels, internal, non-destructive testing and certification by qualified inspector	4 years

Renewal

Filters are renewed when additional filtration capacity is required or when the existing filter elements become obsolete and can no longer be manufactured. For older filters where original elements are no longer manufactured, we may source equivalent elements from after-market suppliers. Below is a summary table outlining the forecast renewal projects for the upcoming planning period.

Table D.52: Forecast projects during planning period.

Project Name	Description	completion period
Taupo filter installation	Install additional filter for redundancy.	4 years

D.6.6. Buildings and grounds

Asset overview

Many stations have buildings that were installed at the time of pipeline construction. These house important equipment like SCADA communications, electrical switchboards, uninterruptible power supplies, provide space for storing spare parts, and serve as workshops for onsite repairs.

All station grounds are secured with fencing, with emergency exit gates wherever necessary to ensure safe egress in emergencies. Most of these sites are owned, though in some cases, the land is leased. We cover our station grounds with a specific size metal to suppress weeds, prevent mud and allow vehicle access to site. Recently upgraded stations have larger concrete pads around the equipment to make it easier to complete maintenance tasks and install touch potential mitigation systems.

Condition and performance

Overall condition and performance are good, with regular maintenance completed to keep buildings clean, painted and watertight. Stations susceptible to flooding are designed so equipment is located above the flood water line. Grounds are maintained with regular weed spraying and when required additional metal is laid. Station fencing is prone to corrosion at the interfaces between the concrete footings and air. This requires ongoing maintenance and sometimes full replacement of fences.

Risks and issues

Due to the original date of construction and the minimal electronic communications systems at the time of construction. Some buildings are too small to house required electronic equipment. This has led to the installation of additional buildings during major upgrades. Fences are ageing and are subject to corrosion and a requirement of the standards we operate under, emergency gates need to be installed at some of our older stations, where emergency gates were not required under the previous standard.

Table D.53: Risk and issues.

Risk/Issue	Consequence	Mitigation
Site building too small	Additional electronic equipment cannot be installed or spares stored on site.	Additional building installed or new electronic equipment installed in fit for purpose outdoor enclosure.
Ageing station fencing reaching end of service life	Fences are beginning to corrode, especially at the ground to air interface.	Fences are inspected and additional coatings added. Replace fences when corrosion is severe.
Emergency gates not installed	Non-compliant with standards and limited egress during an emergency.	Gates are installed as part of any major upgrades completed onsite. Additional controls are implemented during higher risk work activities, such as the removal of fence netting.

Lifecycle management

Maintenance

Maintenance for buildings and grounds is minimal with most buildings built with concrete block or colour steel. Maintenance activities are summarised below.

Table D.54: Maintenance and inspection activities

Description	Activity	Frequency
Station and fence inspection	Inspect station buildings and grounds for security, corrosion and unauthorised access.	6 months
Weed control	Spray station grounds for weeds.	6 months
Rodent control	Bait stations or contractor if infestation occurs	12 months
Building cleaning	Clean external surfaces of building to maintain paint.	2 years

Renewal

Buildings are replaced when they become too small to house required equipment and there is insufficient room onsite to install a new building, or if there is a risk of flooding. Fences are generally maintained until corrosion impacts the integrity of the fence, leading to a possible failure or potential to collapse.

Table D.55: Forecast projects during planning period.

Project Name	Description	Completion Period
Mokau fence replacement	The fence at Mokau compressor station has non repairable corrosion at the interface.	12 months
Emergent fence replacements	Station fences might become irreparable during the planning period and require full replacement.	10 years

D.7. Station components

The station component asset class includes seven asset fleets. These fleets meet a range of needs, including leak detection via odorisation, isolation of pipelines, contaminant filtration, accurate measurement of gas consumption, and controlled pre-heating of natural gas prior to pressure reduction.

D.7.1. Main line valves

Asset overview

The main line valve (MLV) asset fleet consists of valves which are typically placed at 32 km intervals across the gas transmission network. These valves are required for isolating pipeline sections during maintenance, repair, or emergencies. Most MLVs have valves installed underground, with actuators positioned above ground, and are actuated either mechanically or hydraulically via extended shafts. MLVs can be operated:

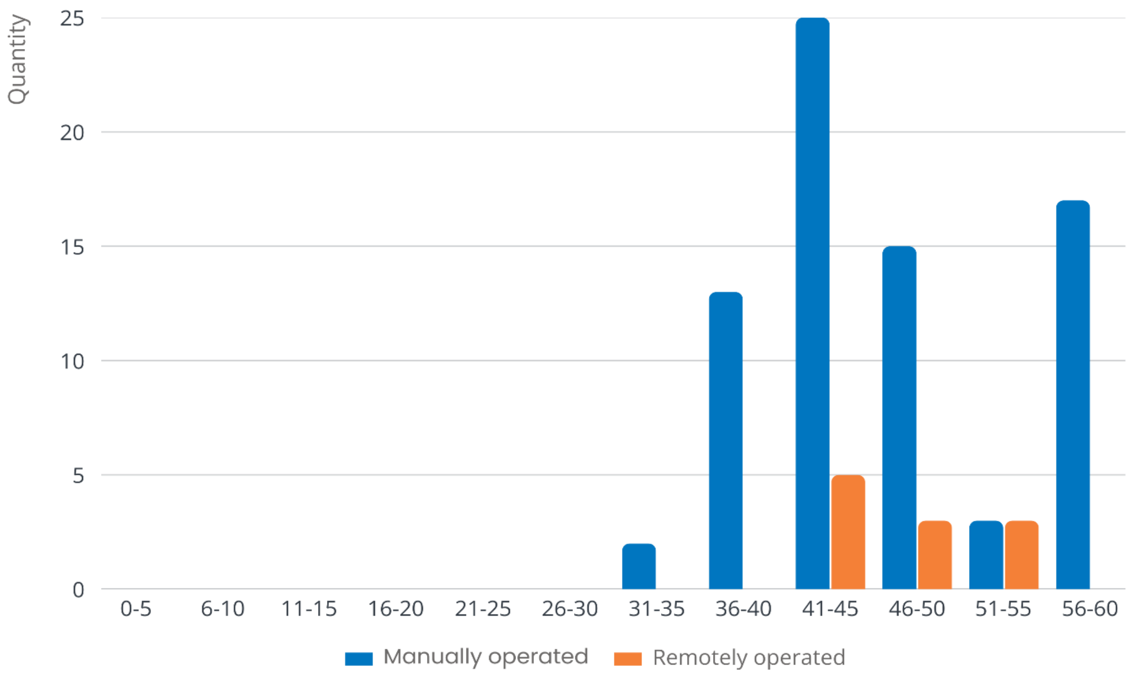
- remotely from the control room through the SCADA system,
- automatically by low-pressure trip units that detect pipeline pressure loss,
- manually, using a handwheel or hydraulic hand pump.

Actuators primarily use a gas over hydraulic oil to operate.

Age profile

The age profile of MLV mirrors that of the pipelines as they were installed at the same time as the pipeline. As these assets continue to age, challenges are emerging regarding the availability of replacement components for the actuators.

Figure D.6: Main line valves age profile



Condition and performance

Though originally installed in rural areas, many MLVs are now in urban environments due to land use changes. MLVs operate using natural gas, which is safely vented; however, increasing urbanisation has made routine maintenance challenging because of noise and odour issues. This requires advance notification to local landowners or, in some cases to Fire and Emergency New Zealand to prevent call outs for the smell of gas.

Most of our MLV actuators are now considered obsolete, with spare parts becoming increasingly scarce or unavailable. As these assets age, replacement components are often no longer commercially available. When spares are no longer available from the manufacturer, we will source aftermarket products, including local manufacturing.

Risks and issues

Risks associated with MLVs arise from ageing components and changing land use around pipeline infrastructure. As MLVs play a critical role in isolating sections of the network for maintenance or emergency response, any failure can compromise network operability and safety.

A key challenge is the growing obsolescence of actuator components, with spare parts becoming increasingly scarce. While some spare parts are retained from decommissioned assets or fabricated locally, reliance on ageing equipment is becoming a risk that we are currently revising our lifecycle management strategy to address.

Additional risks include inadequate valve sealing during isolation, corrosion of buried components due to degraded coatings, and gas leakage from valve stems and bodies. The table below outlines key risks, their potential consequences, and the corresponding mitigation measures.

Table D.56: Risk and issues

Threat or issue	Consequence	Controls
Obsolete actuators components	MLVs cannot be maintained or operated.	Removed actuators are kept for spares. Components are manufactured locally.
Inadequate valve sealing during isolation	Pipeline is not adequately isolated for maintenance or repairs.	Scheduled valve testing and inspections. Valve cavity flushing. Contingent isolation plans for known faulty valves.
Poor or unknown coating condition of buried components	This may lead to corrosion of buried components and increase the risk of gas leaks.	Routine maintenance and inspection. Cathodic protection. Valve stem wrap and coating remediation.
Leaking valve stems and bodies	Gas leak to atmosphere.	Valve repair or replacement. Routine gas or leak detection checks.

Lifecycle management

Maintenance

MLVs maintenance requirements are summarised below.

Table D.57: MLV maintenance and inspection activities

Activity	Frequency
Function check operation of MLV Operate bypass valves and check for leaks Inspect for corrosion Verify actuator operation, instrumentation operation, hand pump operation, check reference tank pressure, function check trip settings	6 months
Power supply and uninterruptible power supply checks End to end instrument checks to control room	12 months
Grease and operate riser end caps	3 years

Activity	Frequency
Battery replacement	4 years
Overhaul low pressure instrument regulators and pressure relief valves	4-5 years
Replace low pressure trip instrument regulator	8 years

Renewal

We are reviewing the lifecycle management strategy for MLV to address obsolescence and to reduce high replacement costs. The plan aims to optimise the number of valves on the network without compromising network isolation integrity or effectiveness, reallocating non-essential valves as spares and prioritising renewal of critical ones to ensure long-term availability of spares and operation.

Table D.58: Forecast projects during planning period.

Project Name	Description	completion period
MLV lifecycle plan	Replacement of critical valve actuators across the network	10 years

D.7.2. Heating systems

Asset Overview

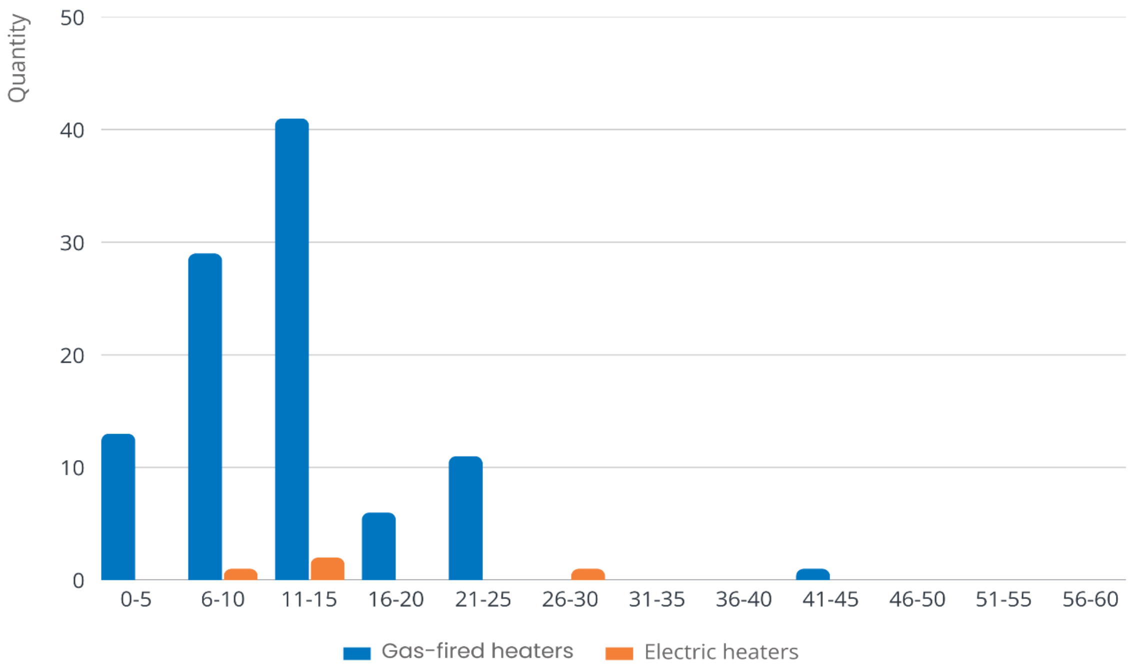
When gas pressure is reduced by pressure regulators at delivery points, the gas temperature decreases due to the Joule-Thompson effect. To maintain gas temperature above the lower limit specified in NZS 5442, and to protect equipment material from negative operating temperatures, gas must be heated to an appropriate temperature prior to pressure reduction.

We use two heating systems: gas-fired water bath heaters and electric heaters. Gas-fired units heat water in a vessel by burning gas in a fire tube; pressurised gas flows through tubes in the heated water, raising its temperature to the required level. Electric heaters heat gas directly by passing it through a vessel containing electric heating elements.

Age profile

The age profile reflects upgrades completed to meet higher or new demands on our delivery points by installing newer and larger heaters over the last 15 years. Our heater refurbishment program is working well and heaters over 20 years old are in good condition. Heater fuel gas trains are ageing with equipment replaced based on condition.

Figure D.7: Water bath heaters age profile



Condition and Performance

There has been significant improvement in the overall condition of the water bath heater shells and pressure coils due to inspection and refurbishment programs over the last 10 years. The improvement in condition allows us to modify our approach and change to an onsite inspection-based program.

Risks and issues

Over the past 15 years, the installation of larger heaters has kept pace with rising demand at our delivery points. However, recent trends indicate a reversal, with demand now decreasing through these connections. This shift raises concerns about the potential for oversized heaters operating inefficiently and burning excess fuel gas and incurring unnecessary maintenance costs. An example is the closure of the Marsden Point Refinery, which left a large heater in service to support minimal gas flow and requiring a disproportionately high level of maintenance.

Additionally, our heater fuel gas trains have aged, and replacements have been carried out on an ad hoc basis, resulting in a mixture of designs and configurations. As standards have evolved, successive updates have led to increased diversity in design approaches, which may require remediation and standardisation during the planning period to ensure ongoing operation.

The table below summarises the main threats, impacts, and mitigation measures.

Table D.59: Risk and issues

Risk or issue	Consequence	Controls
Oversized heater	Excess fuel gas consumption, emissions and maintenance.	Monitor delivery point throughput, modify fuel gas trains for lower demands. Rotate out larger heaters where possible.
Ad hoc fuel gas train designs	Spares are not standardised across fleet and comply with different standards.	Utilise similar component models and makes during maintenance. Update fuel gas design standard design.

Lifecycle management

Maintenance

Heaters are maintained to ensure reliability during normal operating conditions, with regular inspection and cleaning of fuel gas train components, inspection of heater shell and coils, function testing safety shut down, and temperature control systems.

Heaters are internally inspected every 10 years, aligned with our pressure equipment management plan. Heater shell, structure, flue and pressure coils are inspected for any anomalies that require remediation to ensure pressure integrity. Heaters that require extensive repair are removed from site and refurbished under our capital works program.

Table D.60: Maintenance and inspection activities

Activity	Frequency
Inspect water level, burner operation and temperature control External visual inspection	6 months
Function check heater operation, safety shut off and temperature control system Calibrate instrumentation	12 months
Internal inspection of shell and coils	10 years
Anomaly remediation and repairs	Ad hoc

Renewal

Heaters are renewed if demand increases and the heater no longer meets the determined outlet temperature, when an inspection identifies anomalies that require remediation to maintain pressure integrity, or if the inspection value is above a specific threshold. Our renewal forecast has decreased over recent years due to their improved condition following focused refurbishment efforts.

Table D.61: Forecast projects for planning period

Project Name	Description	Completion period
Large heater inspection program	Large heater coil and shell inspection program.	10 years
Emergent remediation program	Heaters with identified anomalies are renewed offsite to maintain pressure integrity.	10 years
Fuel gas train standardisation	Program to standardise fuel gas trains.	10 years

D.7.3. Odorisation plant

Asset overview

The purpose of gas odorisation is to enable the detection and location of gas leaks. Gas must have a distinctive and unpleasant odour so that it can be readily detected in the air by anyone with a normal sense of smell, well before a combustible mixture can develop.

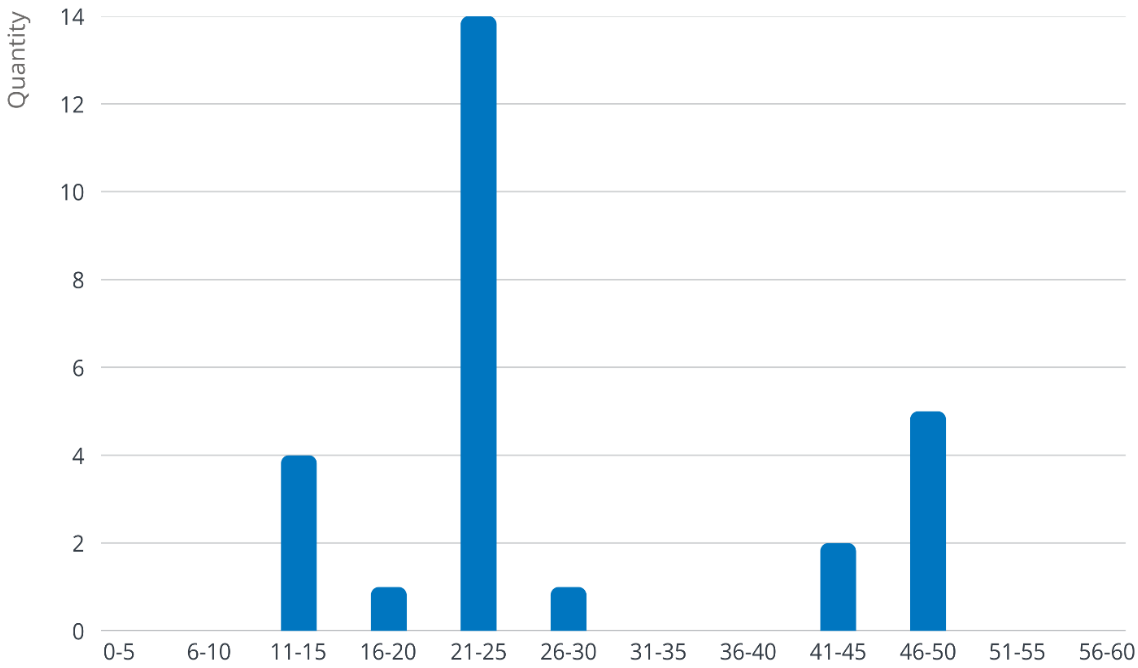
Our odorisation plants are four main stations injecting a form of mercaptan into main pipelines and bypass tanks where gas is not odorised within the main pipeline or is required to increase the level of smell due to the local environment or masking occurs e.g. Rotorua due to the smell of hydrogen sulphide.

Our four main station contains bulk storage tanks, electronic metering and injection systems to inject the required amount of odorant required to meet flow conditions. Each station has built-in redundancy with additional pumps and controllers, and as a failsafe a small bypass tank which injects odorant via a differential pressure operating across an orifice. This is the same system used on our delivery points where the main pipeline is not odorised, or the risk of masking is possible.

Age profile

While our odorant plants are relatively old, most are steel or stainless steel tank systems and in good condition. Two electronic injection systems need to be replaced due to obsolescence.

Figure D.8: Odorisation plant age profile



Performance and condition

The current performance and condition of our odorisation plant is good, with two electronic inject plants nearing obsolescence and planned for replacement.

Risks and issues

The current risk and issues with our odorant fleet are minimal with planned replacements of ageing electronic odorant units being replaced in the planning period.

Table D.62: Risk and issues

Risk or issue	Consequence	Controls
Ageing electronic odorant injection systems	Failure to back up tank system	Increased manual readings. Planned replacement of ageing systems

Lifecycle management

Maintenance

Odorant tanks are managed according to our pressure equipment management plan and are inspected by a qualified vessel inspector to comply with relevant standards. Our four large odorant systems are subject to inspection and certification to comply with the Hazardous Substances and

New Organisms Act 1996. Downstream odorant tests are completed by gas distribution companies to verify the odorant level on a regular basis. Abnormal results are reported to us for investigation and remediation.

Odorisation plants maintenance requirements are summarised below.

Table D.63: Maintenance and inspection activities

Activity	Frequency
Odorant liquid level check and system checks	1 month
Odorant operational checks	6 months
Large odorant vessel statutory external inspection Instrument calibration and functional checks Location test certificate inspection	12 months
Small odorant vessel statutory external inspection Odorant injection pump overhaul	2 years
Odorant tank PSV testing and certification Large odorant vessels statutory internal inspection, or non-destructive testing in lieu of internal inspection	5 years
Small stainless steel odorant vessel statutory internal inspection, or non-destructive testing in lieu of internal inspection	10 years

Renewal

Odorant systems are renewed when electronic components age and are at risk of failing, with lack of replacement spares available. Odorant tanks would only be replaced if anomalies related to pressure retainment and potential loss of containment are excessive and could not be repaired. Two electronic odorant injection systems are planned for replacement in the planning period.

Table D.64: Forecast projects for planning period.

Project name	Description	Completion period
Rotowaro odorant system replacement	Replace injection system controller and pumps.	4 years
Pokuru odorant system replacement	Replace injection system controller and pumps	4 years

D.7.4. Coalescers

Asset overview

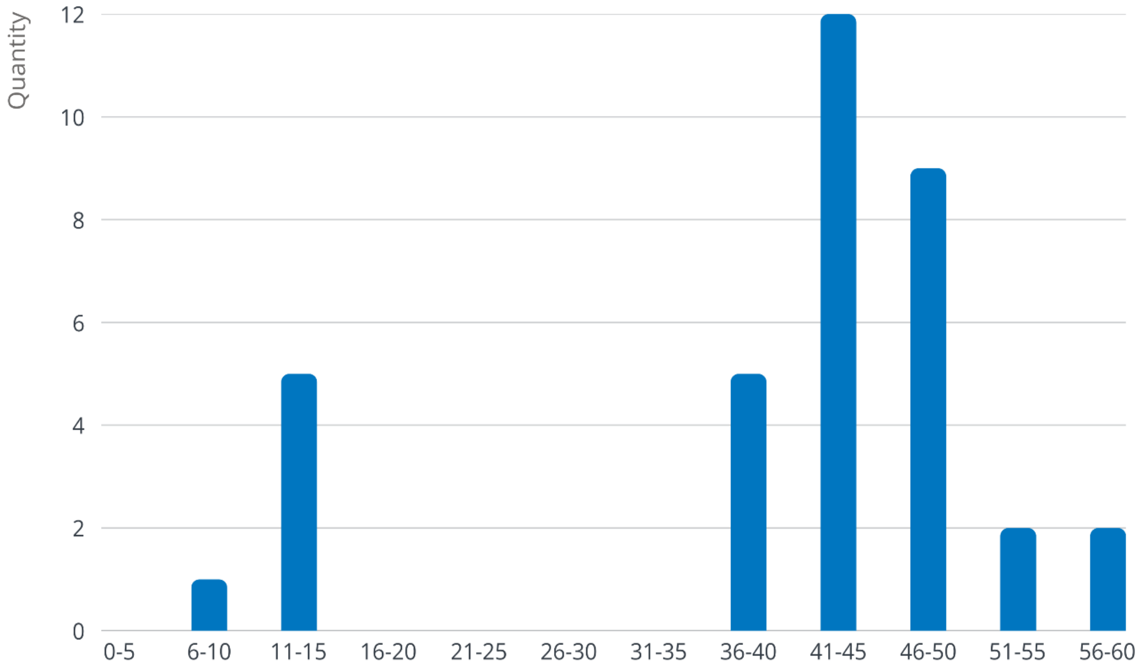
Coalescers are specialised filtration devices installed within the gas network, most commonly on the discharge side of compressor stations and at select large delivery points. Their primary function is to remove fine liquid contaminants and impurities from gas streams to protect downstream equipment and prevent the accumulation of liquids in pipelines.

Coalescers work by trapping tiny liquid particles as gas flows through a cartridge. As these particles accumulate, they merge to form larger droplets, which eventually become heavy enough to fall into a liquid receiver tank for removal. This process ensures that only clean, dry gas continues downstream.

Age profile

This section provides an overview of the age distribution of coalescers across the network. Coalescer age does not determine replacement need and the current age of the fleet is satisfactory.

Figure D.9: Coalescers age profile



Performance and condition

There is a mixture of newer vertically installed coalescers and older horizontally installed coalescers. Modern vertical coalescers are more efficient at removing liquids from the gas streams. The fleet of horizontal coalescers are operating satisfactorily. The coating and internal condition on most of the coalescers is in good condition.

Risks and issues

The following table outlines key issues, associated consequences, and the control measures in place to mitigate these risks.

Table D.65: Risk and issues

Threat or issue	Consequence	Controls
Older horizontal coalescers are less effective at removing fine fluids and mists than vertical units.	Some fluid carries over into downstream pipelines.	Routine replacement of coalescer elements Cleaning pig run on pipelines

Lifecycle management

Maintenance

Coalescers are managed by our pressure equipment management plan, requiring internal and external inspections to comply with *AS/NZS 3788: 2006,* Pressure Equipment In-Service Inspection. The external coating is maintained to a high standard as the primary means to prevent corrosion. Coalescer internal elements are replaced at the time of the internal inspection.

Table D.66: Maintenance and inspection activities

Activity	Frequency
Operate and inspect level switches, dump valves and controllers External visual inspection for corrosion	6 months
Calibrate and function check instrumentation	12 months
Statutory external vessel inspection and certification	2 years
Statutory Internal visual inspection or non-destructive testing	4 years

Renewal

Coalescers are replaced if the flow demand exceeds the coalescer capacity to remove liquids, anomalies are extensive and exceed replacement cost to remediate, and poor performance leading to contaminated pipelines. Most renewal projects associated with coalescers are related to the replacement of liquid dump systems and instrumentation.

Table D.67: Forecast projects for planning period.

Project Name	Description	completion period
High level switch replacement	Replace existing high level switch with newer model	12 months
Emergent work	Replace instrumentation and dump system components.	10 years

D.7.5. Metering systems

Asset overview

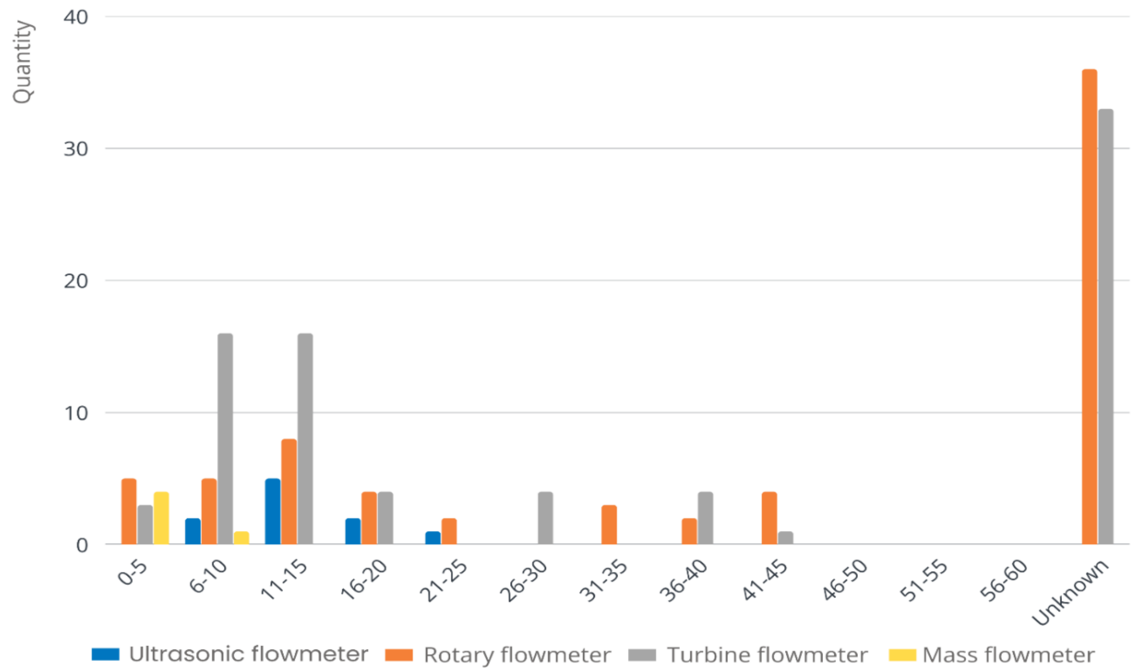
Metering systems are used across the transmission network to measure the volume of gas delivered to customers, distribution networks, and fuel gas consumption by gas fired heaters and gas driven compressors.

Metering systems will vary in size, type and configuration depending on the volume of gas required. Our larger systems consist of two flowmeters that can be configured to complete routine online series prove testing. This includes a flow computer, temperature and pressure transmitters with a gas chromatograph measuring the gas composition to determine a calorific value. Our largest meters are ultrasonic flowmeters; many of our metering systems use turbine flowmeters as they operate across a broad range of flow characteristics. We use diaphragm meters for smaller stations and to measure fuel gas consumption for gas fired heaters. Flowmeters provide live flow rate data to flow computers or flow correctors which use pressure and temperature to calculate the volume and energy of gas.

Age profile

Our age profile indicates that a significant number of flowmeters will reach their 25-year replacement threshold during the planning period. While some flowmeters have previously had their service life extended through refurbishment, this is no longer feasible for all units due to limited availability of spare parts from manufacturers. We are actively addressing cases where the age of flowmeters is unknown by gathering data during our routine testing and certification programme.

Figure D.10: Age profile



Performance and condition

Most of our flowmeter fleet is in satisfactory condition, however we have a reasonable portion which need to be replaced in the next three years to manage age and condition of our fleet. Programs in this planning period will replace current grade 1 and 2 flowmeters.

Risks and issues

The below table outlines key risks associated with metering systems, their potential consequences, and the control measures.

Table D.68: Risk and issues

Risk or issue	Consequence	Controls
Flow rate exceeds meter design	Inaccurate measurement leading to financial loss	Flow rate monitoring.
Flowmeter contamination	Reduced meter accuracy and increased maintenance requirements	Inlet filters and coalescers on compressor stations. Planned meter readings, testing and inspection. Meter removal and recertification.
RTU to corrector interface issue	Communication errors may lead to inaccurate data	Monthly manual meter readings.
Obsolete ultrasonic sensors	Flowmeter removed from service	Operate series prove verification flowmeter. Carry additional inventory of spares. Planned replacement.

Maintenance

Metering systems are maintained and inspected in accordance with strict frequencies determined by transmission pipeline operating codes and requirements. An overview of these requirements is in the following table.

Table D.69: Maintenance and inspection activities

ACTIVITY	FREQUENCY
Base volume indication, correction factor indication and primary flow signal integrity system checks	1 month
Large metering systems Base volume indication verification Series prove flowmeter verification Instrumentation accuracy checks Electronic system checks Alarm investigation and remediation Flowmeter lubrication	3 months
Small metering systems Lubricate flow meters Instrumentation accuracy checks Corrector system and battery checks	6 months
Calibrate flow computer and instrumentation	12 months
Test and calibrate rotary, turbine and diaphragm flowmeters exposed to contamination or reduced accuracy	2 years
Visual internal inspection of ultrasonic flowmeter	2 years
Test and calibrate corrector	3 years
Test and calibrate rotary, turbine and diaphragm flowmeters	5 years
Calibrate coriolis flowmeter	10 years
Calibrate ultrasonic flowmeter	15 years

Renewal

Metering systems are renewed as the individual components age, condition deteriorates and when testing determines performance issues. Flowmeters are generally replaced around 25 years, due to declining accuracy and an increased likelihood of failure after 25 years. Our current flow computer fleet is ageing, and we are planning on replacing them over the planning period with an integrated SCADA remote terminal unit. A program is underway to replace our flow correctors with a newer model. Ultrasonic flowmeters can be renewed by upgrading the sensors and main computer unit.

Table D.70: Forecast projects for planning period

PROJECT NAME	DESCRIPTION	COMPLETION PERIOD
Reactive meter replacements	Replacement of meters that fail certification and calibration	12 months
Planned meter replacement	Age based replacement of flowmeters	12 months
Planned meter replacement	Age based replacement of flowmeters and upgrade ultrasonic meter components	4 years
Corrector replacement	Age based replacement of correctors	4 years

PROJECT NAME	DESCRIPTION	COMPLETION PERIOD
Flow computer replacement	Age based replacement of flow computers integrated into a SCADA remote terminal unit	10 years

D.7.6. Cathodic protection systems

Asset overview

Cathodic protection (CP) systems are installed across our network to protect steel pipelines from corrosion using an impressed current system. CP rectifier sites are distributed across the pipeline network and locations have been selected to ensure full pipeline coverage. Power outages at a single rectifier can generally be compensated for by the rectifiers on either side of it for short durations. Most CP rectifiers are monitored remotely with intelligent power supply systems, allowing for quick identification and remediation of rectifier outages.

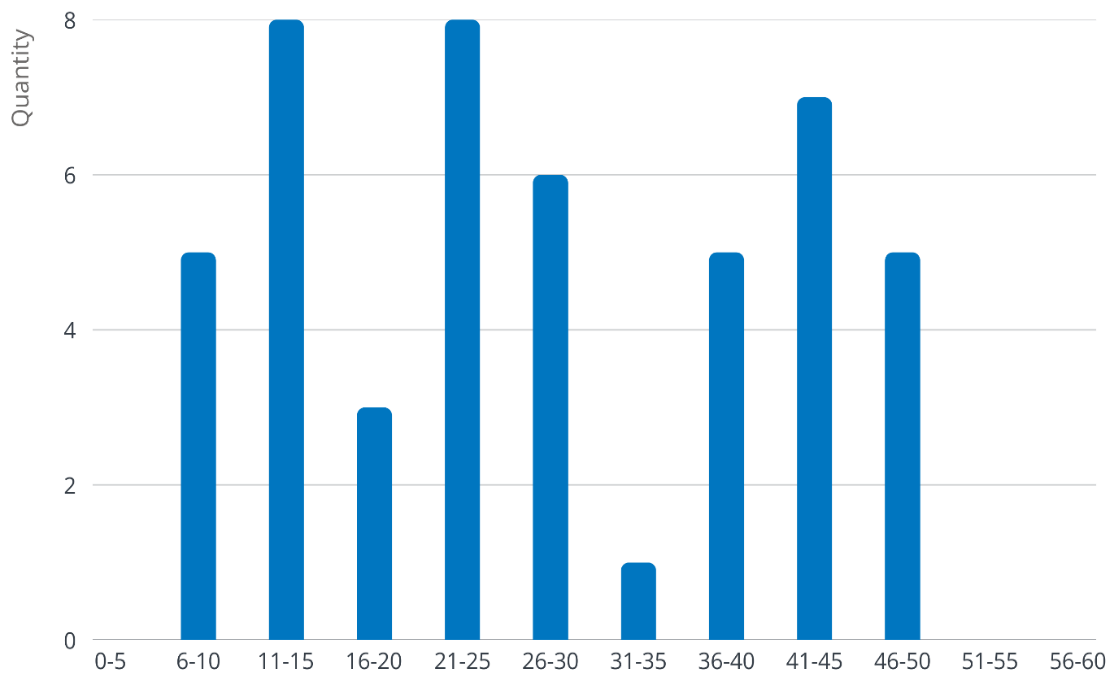
A pole or ground mounted CP system rectifier site consists of the following equipment:

- rectifier unit that draws low voltage DC current from the pipeline
- buried anode bed that discharges current to ground
- AC power supply
- cables connecting the rectifier, anode bed and pipeline
- intelligent power supply remote control and monitoring unit.

Age profile

Although this is an ageing fleet, regular performance monitoring combined with the replacement of individual components can extend operation beyond typical design life.

Figure D.11: Age profile



Condition and performance

Anode beds deteriorate over time as they discharge, as the anodes are consumed rectifier output current will decrease and voltage increases. Based on this, we can determine when anode beds are performing poorly and approaching the end of their life. While the fleet is in good condition, some rectifiers and anodes are beginning to perform poorly and require planned replacement in the planning period.

Risks and issues

If pipeline coating deteriorates or urbanisation increases around our pipelines this impacts the CP systems location and performance, often requiring our systems to be relocated or outputs increased.

Table D.71: Risk and issues

Risk or issue	Consequence	Controls
Decreasing rectifier performance or coating degradation	Inadequate CP protection, leading to reduced corrosion protection	Replacement programme, routine monitoring and testing, excavation assessment programs. DCVG surveys, ILI pigging.
Increased urbanisation around pipeline easements	Relocation of CP systems and test points. Increased output capacity required, quicker deterioration of anodes.	Actively work with developers to identify future planning and relocation. Routine performance monitoring.

Lifecycle management

Maintenance

The CP system is operated, maintained, and inspected in accordance with established maintenance and operational standards. Regular monitoring and testing are conducted at specified intervals to ensure the system's effectiveness in preventing pipeline corrosion. Key activities include rectifier performance checks, test point surveys, electrical isolation testing, and assessments of anode beds and insulating joints. These inspection activities are summarised in the table below.

Table D.72: Maintenance and inspection activities

Activity	Frequency
CP rectifier monitoring	6 days a week
CP 'on' monitoring for selected test points	3 months
CP Test Point 'on-off' surveys in selected residential areas	6 months
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)	12 months
Cased crossing electrical isolation testing	12 months
Visual inspection of rectifier unit	12 months
Integrity checks for sacrificial anode beds	12 months
Test point inspections	12 months
ER probe inspections	12 months
Power earthing and bonding testing	4 years
Integrity checks for impressed current anode beds	7 years

Renewal

We renew CP systems when they no longer protect the pipeline from corrosion, enclosures are damaged or corroded, or individual components fail. Anodes are monitored and replaced when test results suggest the anode is approaching end of life.

Table D.73: Forecast projects for planning period.

PROJECT NAME	DESCRIPTION	COMPLETION PERIOD
Emergent relocations	Relocation of CP rectifiers, coupons, test points and anodes	10 years
Emergent replacements	Emergent replacement of CP systems components that deteriorate below performance requirements in planning period	10 years
Emergent insulating joint replacements	Replacement of insulating joints due to failure during planning period.	10 years

D.7.7. Gas chromatographs

Asset overview

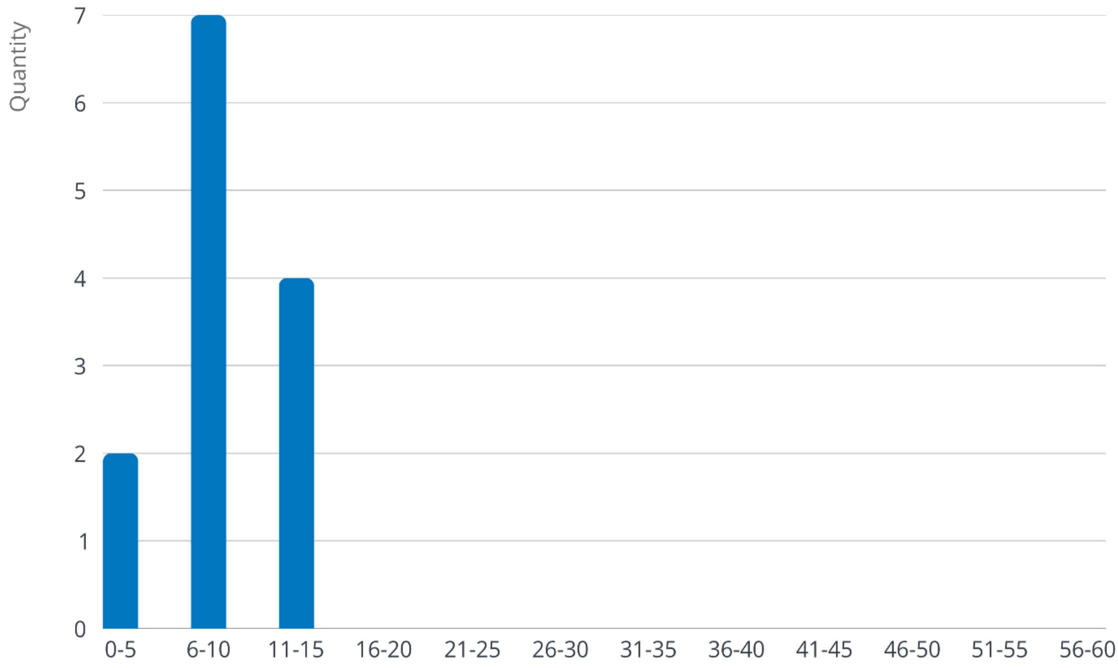
The energy content of gas is calculated by flow computers using data obtained from the volume, pressure, temperature measurements and gas composition data derived from a gas chromatograph (GC). GCs are installed on stations with our larger metering systems such as pipeline offtakes or direct connect customers.

A GC is an instrument used for analysing the components of the natural gas stream, such as methane, nitrogen, carbon dioxide and pentane. GCs analyse natural gas by injecting a sample into chromatographic columns, then calculates energy content and other key properties for determining the energy value.

Age profile

The figure below illustrates the age profile of GCs across the network. While four units are older than 10 years, we are comfortable with their current condition and operation.

Figure D.12: Age profile



Condition and performance

The current performance of our GC fleet is good, though condition is beginning to decline due to age, limited spares and software updates becoming unavailable. We are comfortable with the condition and performance of our GC fleet. We hold a spare unit for prompt replacement.

Risks and issues

We do not have any material concerns with risk or issues related to the GC fleet, given that obsolescence is being managed effectively.

Lifecycle management

Maintenance

GCs are maintained and inspected in accordance with frequencies determined by transmission pipeline operating codes. An overview of these are in the following table.

Table D.74: GC maintenance and inspection activities

Activity	Frequency
Automatic calibration	Weekly
Verify automatic calibration results, verify sampling system and carrier gas system operation and pressures, manual calibration	1 month
Change filter elements	12 months
Exchange calibration gas bottles	5 years (expiry date)
Exchange carrier gas	As required

Renewal

GCs are replaced upon failure, with a hot spare unit being maintained in our workshop. The failed unit is sent back to the manufacturer for refurbishment or complete replacement. GCs are not critical to the operation of the network and metering systems can be manually updated to manage GC failure.

Table D.75: Forecast project for planning period

PROJECT NAME	DESCRIPTION	COMPLETION PERIOD
Gas chromatograph replacement	Reactive replacement and spares strategy	10 years

Firstgas

Appendix E. Network Development

Network development refers to capital investments that expand the capacity, functionality, or extent of the transmission network. These include consumer connections, system growth, and targeted upgrades to stations and pipelines.

This section outlines our approach to the development of the gas transmission network, with a focus on ensuring capacity, security, and adaptability in the face of changing demand. It provides a comprehensive view of how the transmission network is planned and managed to meet the needs of existing and future users, while ensuring compliance with regulations and commercial prudence.

This section also covers how network development is triggered and prioritised through structured planning, modelling, and options analysis, ensuring investments are optimised across performance, safety, and regulatory outcomes.

The section discusses the following topics:

- **network development investments:** categorises development work into consumer connections and system growth, and outlines influencing factors.
- **planning principles and investment drivers:** sets out regulatory compliance obligations, commercial considerations, and proactive planning frameworks.
- **development planning**: describes the end-to-end process from needs identification through to options analysis and solution implementation.
- **station and pipeline capacity upgrades**: details how limitations at delivery points or within pipelines are identified and addressed through targeted infrastructure enhancements.
- **capacity determination**: explains the modelling methodology used to determine current and future operational capacity of pipelines and stations. We also outline how demand is projected and how these forecasts guide upgrade timing and presents forecast data for key pipeline systems and delivery points.
- **schematic diagrams**: provides visual overviews of the transmission network to support spatial understanding of system configuration and development areas.

The above elements provide a comprehensive framework for ensuring the transmission network remains robust, adaptable, and capable of meeting both current obligations and future demands in a changing environment.

E.1. Network development investments

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

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

E.1.1. Consumer connections

We aim to meet consumers' needs by ensuring the transmission network can accommodate their loads within the required timeframe. Gas demand can be broken into 3 main sectors:

- petrochemical production: used as a feedstock as well as fuel
- power generation: used as fuel, in base load or peaking plant
- direct use: used to meet process heat requirements or for other industrial applications.

There is currently significant uncertainty with new connections. At this stage, no provision is made in our 10-year capex connections forecasts (as set out in Schedule 11a in Appendix B).

E.1.2. System growth

Investments in this area include enhancements to the capacity and/or configuration of the transmission network that address potential security breaches, extend into new or developing areas, and cater for organic load growth or changing consumer demand in existing areas.

E.2. Planning principles

The gas transmission network is regulated under a range of legislation and standards as discussed in Appendix C. To meet these requirements, as well as commercial imperatives, the planning principles for the transmission network seek to ensure that:

- all network assets will be operated within their design rating
- design and operation of the assets will not present a safety risk to staff, contractors or the public
- network is designed to meet the Transmission System Security Standard, which includes requirements set out in the Critical Contingency Management Regulations
- reasonable gas supply requirements for customers will be met including a prudent capacity margin to cater for foreseeable short to medium-term load
- equipment is purchased and installed in accordance with good high pressure gas pipeline standards to ensure optimal asset life and performance, and
- investments will provide an appropriate commercial return for the business.

E.3. Investment drivers

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

- potential breaches of the Transmission System Security Standard
- supply to new developments or areas requiring gas connections
- supply to existing connections requiring increased capacity.

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

E.4. Development planning

Planning for system growth investments requires that needs are anticipated so that, by timely investment in additional capacity, potential shortfalls of capacity are avoided, or breaches of the security criteria. The development process involves modelling, planning and designing the gas transmission network, capital budgeting, prioritising the investment programme, and implementing the chosen solutions.

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

E.4.1. Needs identification

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

E.4.2. Options analysis

When the need for a pipeline and/or station upgrade is identified, investment objectives are developed and options to achieve those objectives are evaluated. Options are considered for their financial impacts and the degree to which they effectively address the identified need. The evaluation includes the consequences of doing nothing, or of using commercial mechanisms to manage growth. The options considered are summarised in the business case for the investment.

E.4.3. Solutions

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

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

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

- that the solution cost is not disproportionate to the benefits obtained
- prudency of long-term solutions to short-term issues to avoid asset stranding
- alignment with other work programmes such as asset renewal
- commercial viability of the recommended solution.

Where investment is required, cost-effective options are prioritised to reduce overall costs without compromising safety, and capacity or supply pressure.

Station capacity upgrades

To meet security requirements, a station should be able to meet the predicted peak hourly flow. 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.

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.

Pipeline upgrades

Discrete pipeline networks are analysed individually using demand growth data and normal network operating conditions. Each network must be designed and operated to meet the system security standard.

Where pipeline uncommitted operational capacity is forecast to be at or approaching zero, network reinforcement options or other capacity management options will be identified. Network reinforcement solutions may include pipeline options and/or compressor options. Pipeline upgrade solutions will be considered if there is a suitable business case.

E.5. Network capacity determination

This section sets out the forecast demands on the network and describes the capacity determination methodology.

E.5.1. Sources of data for pipeline and delivery point modelling

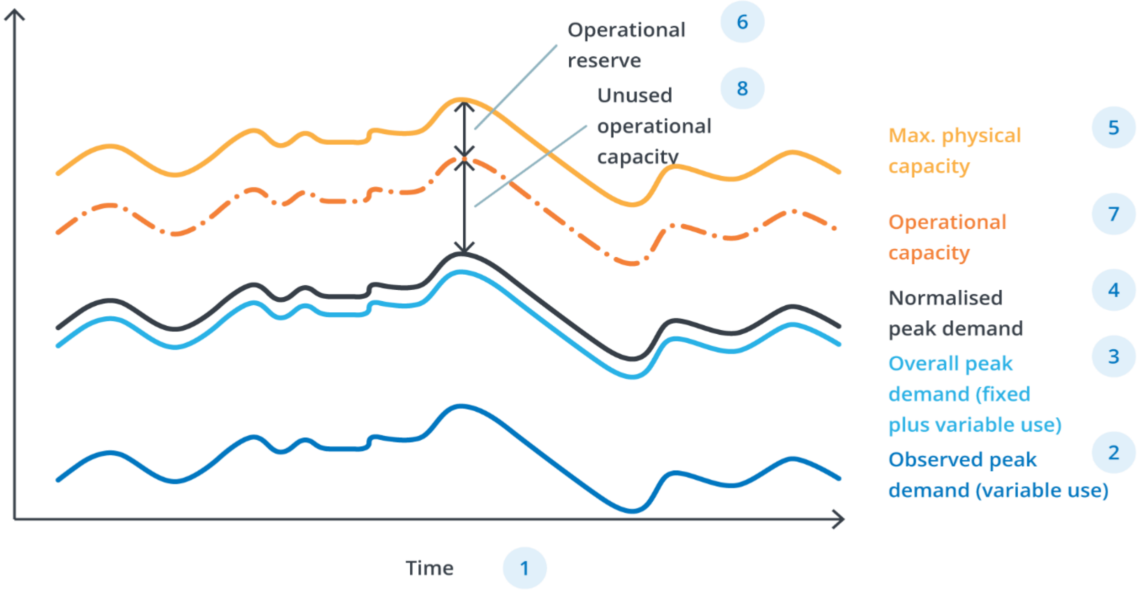
Metered data from OATIS is used for both pipeline and delivery point demand modelling analysis. Data is extracted over many years to identify growth trends for delivery points. For pipelines, hourly metered data profiles are extracted from OATIS and loaded directly into Synergi software (version 4.9.4).

Delivery point equipment capacity is either extracted from manufacturers' data or calculated from performance and asset information located in the asset management information systems. Pipeline data is taken from asset management information systems and GIS.

E.5.2. Pipeline capacity forecasting methodology

The approach to determining the physical capacity of our pipeline network is based on several factors. The steps followed, and the assumptions made are described below. To aid in this description, reference is made to the following diagram. For modelling analysis Synergi software is used, which is a leading, internationally recognised product, produced by DNV GL.

Figure E.1: 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 period.
- determine "fixed" demands
- normalise the variable demand profiles to reflect the long-term trend
- run the model to determine the maximum physical demand that can be sustained without breaching the system security standard
- allow for an "operational reserve" to cover severe winter demands as well as an appropriate "survival time" for the pipeline. This establishes the available "operational capacity"
- deduct existing normalised peak demand at a delivery point from the operational capacity to determine the unused operational capacity at that delivery point.

Step 1 - Time

The peak demand period relevant to the determination of physical pipeline capacity should be the period of greatest demand from the pipeline where pipeline pressures:

- do not fall below the minimum acceptable level at any point; and
- following any depletion, recover to at least their starting levels, indicating that a further such peak demand period would be sustainable.

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

Peak demand on the pipelines occurs during the working week. Overall demand on most pipelines (although not necessarily at all delivery points) is invariably lower on weekends. For this reason, modelling is generally based on the five-days (Monday-Friday, inclusive) in which the highest aggregate demand occurs (the "five-day peak[1]").

At the start of the five-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 reduce. To determine the pipeline's sustainable capacity, pressures must fully recover.

Step 2 - Observed (variable) peak demand

The second step in a physical capacity determination is to assemble gas demand profiles[2] by observing actual variable demand patterns during the five-day peak for all delivery points. 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, forecasting this diversity is not required. 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.

When modelling to determine pipeline capacity, all contractually interruptible load on a pipeline is set to zero.

Dairy factories' peak demand periods do not generally coincide with the five-day peak of the pipelines from which they are supplied. They are modelled as variable loads, which is generally when they are in their off-peak periods. Other large directly connected customers (excluding power stations) are modelled as variable loads according to their actual demand during the five-day peak, unless their demand in that period was so unusually low as to justify an adjustment factor being applied to simulate more typical operation.

Step 3 - Overall modelled peak demand

To determine the overall demand on a pipeline, fixed loads (if any) need to be added into the model.

Currently, only power stations are treated as fixed loads. While their demand is not literally fixed, when power stations are operating at maximum generating capacity, they represent both near-constant and very substantial loads on the relevant pipeline. Power stations can operate at full capacity at any time of the year. Even if they were not actually operating at peak load during the five-day peak, they might in the future. Accordingly, each power station's demand is modelled as its maximum contractual entitlement rather than its actual demand in the five-day peak.

1 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.

2 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).

Step 4 - Normalised peak demand

This step in the capacity determination process is to “normalise” five-day peaks to the relevant long-term trend where appropriate. While actual demand peaks may vary materially from year to year, long-term trends can be discerned for some delivery points. On most of the pipelines[3] 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 capacity

This step is to determine the maximum physical capacity that a pipeline network 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 network necessitates simulating increased demand. This involves applying one or more of the following three methods at a delivery point to a pipeline, or more than one delivery point in certain cases:

- applying a factor to the (normalised) five-day peak
- adding a constant flow rate to the (normalised) five-day peak
- configuring a separate flow profile that adds to the (normalised) five-day peak.

The method(s) used depends on the scenario being modelled, the information available and whether the modelling is being undertaken to provide an indication of the general level of unused physical capacity on the pipeline, or in response to a specific request from a shipper.

- **Method 1** is the most 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.[4] The fixed flow rate is increased until the maximum flow rate short of breaching the system security standard is found.

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3 The Bay of Plenty pipeline does not display a strong overall winter peak.

4 It is also used with flow rate set at the estimated maximum hourly quantity as a conservative first test of a pipeline’s ability to support a prospective new load. That is not to imply such an amount of contractual capacity would be allocated.

- **Method 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. 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 maximum hourly quantity 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 network 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, ensuring that the system security standard is not breached in a manner other than because of events beyond our reasonable control.

The "safe" level of physical capacity is termed the "operational capacity" of a pipeline network. 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.[5] We have adopted a one-in-20-year winter incidence (i.e. severity) level to ensure that transmission capacity shortfalls do not occur at an unacceptably high frequency. While this is the current standard, and is a common standard in many other jurisdictions, future economic testing may identify a requirement to revise this.
- **Survival time:** compression is a key to increasing capacity on most pipelines. The compressor stations are designed with N-1[6] redundancy (as set out in the system security standard). However, a redundant compressor may also fail, or fail to start,[7] 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.

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5 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.

6 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.

7 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.

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 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.

E.5.3. 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 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 peak hourly volume data is used to develop future demand projections based on straight line trends. Where the forecast indicates a decreasing demand, the highest demand for the past 5 years is used.

Some exceptions to the above are when step changes to demand are known include when future demand is expected to increase or decrease 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.

E.5.4. Pipeline capacity forecasts

In general terms, overall network utilisation is decreasing, and we are confident, based on current analysis and assumptions, that we have the operational capacity we require for the next 10 years. Changes to operating condition may require minor investment once/if these are implemented.

North pipeline capacity forecast

Our North pipeline network begins at Rotowaro compressor station near Huntly and finishes at Kauri delivery point, north of Whangarei supplying gas to North Waikato, Auckland and Northland.

The following parameters and assumptions have been incorporated into the modelling:

- peak week was the week ending the 11 Aug 2024
- negligible demand was observed at the Wellsford and Kingseat delivery points during the North pipeline peak week. Pipeline capacity was not determined for those sites
- Alfriston Delivery point has been closed
- contractual capacity is allocated to Kauri and Maungaturoto collectively
- Rotowaro compression was modelled running continuously with a constant discharge pressure of 73 barg
- Henderson compression is not running
- minimum operating pressure at delivery points:
  - Whangarei: 27.5 barg
  - Westfield: 37.5 barg
  - Other delivery points: 32 barg
- aggregate contractual capacity indicated for major points only
- delivery point growth and trend forecast consider recent data since FY17 for most delivery points
- aggregate contractual capacity is apportioned to Bruce McLaren, Henderson, Papakura, Waikumete and Westfield in proportion to the operational capacity for these delivery points during FY24.

Table E.1: Pipeline capacity forecast

Delivery point		Aggregate contractual capacity (GJ/day)	Uncommitted operational capacity (GJ/day)		
			FY25	FY30	FY35
Tuakau 2		1,318	27,017	28,097	no load
Harrisville 2		1,542	21,772	23,012	24,132
Ramarama			11,600	11,622	11,647
Drury 1		133	99,339	101,549	102,748
Pukekohe			45,253	46,655	47,791
Glenbrook		6,500	18,597	18,771	18,917
Greater Auckland	Greater Auckland total	**43,983**	**75,135**	**78,669**	**79,203**
	Bruce McLaren	1,593	11,519	11,548	11,421
	Henderson	2,110	22,487	23,376	No Load
	Papakura	13,504	28,027	28,310	28,755
	Waikumete	5,805	34,429	35,636	35,815
	Westfield	20,971	71,722	73,431	74,540
Hunua (Three DPs)		786	108,924	114,105	116,959
Flat Bush		1,754	84,454	88,978	92,484
Waitoki		969	15,242	15,575	15,777
Marsden 2			8,140	8,140	8,140
Whangarei		574	6,091	5,957	6,152

Delivery point	Aggregate contractual capacity (GJ/day)	Uncommitted operational capacity (GJ/day)		
		FY25	FY30	FY35
Kauri and Maungaturoto	5,200	4,004	3,697	3,717
Waiuku		3,923	4,031	no load
Warkworth 2	1,656	381	378	383

Bay of Plenty pipeline capacity forecast

Our Bay of Plenty pipeline network originates at the Pokuru compressor station near Te Awamutu, delivering natural gas eastward to destinations including Tauranga, Rotorua, Whakatane, and terminating in Gisborne.

The following parameters and assumptions have been incorporated into the modelling:

- peak week for this pipeline network was the week ending 24 November 2023
- 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 is not running
- Rangiuru lateral is operated as a distribution intermediate main. The minimum acceptable pressure at the inlet to the Rangiuru delivery point has been taken as 10 barg. Although not defined in the Gas Transmission Security Standard, 10 barg is the minimum accepted pressure for distribution
- Minimum operating pressure at delivery points:
  - Rangiuru: 10 barg
  - Reporoa, Broadlands & Taupo: 5.5 barg
  - other delivery points: 32 barg
- Broadlands biogas plant, commissioned in 2024, adds biogas to the pipeline from Reporoa to Taupo, supplementing the gas supply. To facilitate this plant, the pipeline between Reporoa to Taupo operates below 14 barg. Uncommitted operational capacity at Broadlands and Taupo are based on this lowered operating pressure
- aggregate contractual capacity indicated for major points only
- delivery point growth and trend forecast consider recent data since FY2017 for most delivery points
- Putururu delivery point forecast since 2022 due to closure of a major user.

Table E.2: Pipeline capacity forecast

Delivery point	Aggregate contractual capacity (GJ/day)	Uncommitted operational capacity (GJ/day)		
		FY25	FY30	FY35
Broadlands		2,740	2,759	2,779
Edgecumbe (both DPs)	3,072	8,652	5,787	5,968
Gisborne	856	3,988	3,211	3,278

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Delivery point	Aggregate contractual capacity (GJ/day)	Uncommitted operational capacity (GJ/day)		
		FY25	FY30	FY35
Mount Maunganui	2,594	4,869	2,293	2,265
Tauranga (Includes Pyes Pa)	1,176	3,818	3,010	3,328
Kawerau (Three DPs)	2,437	17,346	17,514	19,747
Kihikihi		166,927	170,108	173,051
Kinleith (both DPs)	11,169	70,401	67,325	80,740
Lichfield (both DPs)	5,460	28,684	23,302	23,374
Opotiki		3,449	3,620	3,770
Putaruru		31,926	32,584	No load
Rangiuru		1,228	1,228	1,228
Reporoa	1,814	9,965	8,548	8,910
Rotorua	1,101	4,587	3,558	3,617
Taupo		1,507	1,510	1,514
Tauriko		5,692	5,933	6,059
Te Puke		3,145	3,319	3,438
Tirau (Both DPs)	540	8,256	7,766	
Tokoroa		52,586	56,860	60,329
Waikeria		91,527	No load	No load
Whakatane	3,623	7,088	4,172	4,839

Central North pipeline capacity forecast

Our central North pipeline network supplies gas to Hamilton, Waipa and Matamata Piako regions with compressed gas from Rotowaro compressor station. The following parameters and assumptions have been incorporated into the modelling:

- peak week modelled was the week ending 6 October 2024, for the normal operating configuration of the Central North pipelines
- compression at Rotowaro was modelled running continuously with a constant discharge pressure of 73 barg
- pipeline configurations include supplying compressed gas from Rotowaro compressor station to Pokuru offtake and closing off supply from the South 200 pipeline
- minimum operating pressure at delivery points:
  - Pokuru offtake: 66 barg
  - other delivery points: 32 barg
- delivery point growth and trend forecast consider recent data since FY2017 for most delivery points
- aggregate contractual capacity indicated for major points only.

Table E.3: Pipeline capacity forecast

Delivery Point	Aggregate contractual capacity (GJ/day)	Uncommitted operational capacity (GJ/day)		
		FY25	FY30	FY35
Cambridge	1,910	899	792	1,094
Greater Hamilton	6,103	2,479	2,302	2,126
Horotiu		4,605	5,517	6,531
Kiwitahi (Both DPs)	950	2,754	1,427	922
Morrinsville (Both DPs)	830	1,832	1,158	1,210
Pokuru offtake		9,063	10,581	10,901
Tatuanui	1,400	1,305	843	1,240
Te Rapa	6,500	2,174	2,751	3,301
Waitoa	1,503	1,794	1,778	1,315

Central South pipeline capacity forecast

Our central South pipeline network supplies gas in the Taranaki region from Waitara south to Eltham. The following parameters and assumptions have been incorporated into the modelling:

- peak week was the week ending 02 August 2024
- Pokuru offtake was set to zero during modelling
- compression at Kapuni was modelled running continuously with a constant discharge pressure of 75 barg
- compression at Mahoenui is not running
- minimum operating pressure at delivery points set to 32 barg
- delivery point growth and trend forecast consider recent data since FY2017 for most delivery points
- aggregate contractual capacity indicated for major points only.

Table E.4: Pipeline capacity forecast

Delivery point	Aggregate contractual capacity (GJ/day)	Uncommitted operational capacity (GJ/day)		
		FY25	FY30	FY35
Eltham	0	8,577	8,588	8,603
Inglewood	0	7,221	7,253	7,299
Kaponga	0	3,136	3,140	No Load
New Plymouth	3,505	2,610	2,748	2,883
Stratford	0	49,464	65,190	74,453
Waitara	0	4,241	6,119	773

South pipeline capacity forecast

Our South pipeline network supplies gas from south Taranaki to as far as Hastings and Wellington. The following parameters and assumptions have been incorporated into the modelling:

- peak week was the week ending 10 May 2024

- Kapuni compression was modelled running continuously with a constant discharge set pressure of 75 barg
- Kaitoke compression was modelled running continuously with a discharge set pressure of 80 barg
- FY25 compressor operation:
  - Kapuni existing configuration with one of two compressors available: Kapuni #2 or Kapuni #3.
  - Kapuni #5 removed from service
  - Kaitoke # 1 compressor running and Kaitoke #2 unavailable
  - Due to capacity limitation of Kaitoke #1 compressor, uncommitted operational capacity at Hastings delivery point is negative. This can be mitigated by operating Kapuni at pressures higher than 75 barg.
- FY30 and FY35 compressor operation:
  - Kapuni existing configuration with one of two compressors available: Kapuni #2 or Kapuni #3
  - Kapuni #5 removed from service
  - New Kaitoke #3 and #4 running and Kaitoke #2 unavailable
  - Kaitoke #1 removed from service.

Minimum operating pressure at delivery points:

- Tawa A and B: 10 barg
- Waitangirua: 37 barg
- Other delivery points: 32 barg

- 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
- 600 pipelines regulated to 64.5 barg between Hawera delivery point and Kaitoke compressor station
- delivery point growth and trend forecast consider recent data since FY2017 for most delivery points
- aggregate contractual capacity indicated for major points only.

Table E.5: Pipeline capacity forecast

Delivery point	Aggregate contractual capacity (GJ/day)	Uncommitted operational capacity (GJ/day)		
		FY25	FY30	FY35
Ashurst	0	6,715	13,801	15,300
Belmont	4,526	6,652	17,388	19,957
Dannevirke	0	5,274	13,696	15,162
Feilding	877	3,593	5,675	5,963
Foxton	0	6,852	25,272	30,457
Hastings (2 DPs)	11,087	586	6,730	7,756
Hawera (2 DPs)	1,245	40,786	51,217	51,675

Delivery point	Aggregate contractual capacity (GJ/day)	Uncommitted operational capacity (GJ/day)		
		FY25	FY30	FY35
Kaitoke	0	2,970	3,003	3,057
Kakariki	0	7,108	9,341	9,465
Greater Kapati	701	5,870	17,375	21,169
Lake Alice	0	3,836	4,893	5,029
Levin	889	4,950	7,569	8,187
Longburn	869	4,630	3,891	7,965
Manaia	0	4,334	4,360	4,382
Mangaroa	0	5,418	9,568	10,590
Marton	726	6,651	9,147	9,404
Otaki	0	5,751	18,567	22,708
Pahiatua (Both DPs)	2,277	1,488	2,287	2,486
Palmerston North	3,028	3,340	4,562	4,871
Patea	0	18,939	No Load	No Load
Takapau	0	7,450	12,320	13,652
Tawa (Both DPs)	8,824	7,202	7,397	7,397
Greater Waitangirua	1,538	5,883	18,022	20,480
Waitotara	0	7,143	29,039	No Load
Whanganui	4,200	29,176	35,362	37,289
Waverley	0	644	654	663

Frankley road pipeline capacity forecast

Our Frankley pipeline network supplies compressed gas to some large industrial plants in the Taranaki region. The following parameters and assumptions have been incorporated into the modelling:

- peak week was the week ending 08 September 2024
- modelling pressure was based on gas entering the pipeline at Frankley Road, at a constant pressure of 44 barg
- TCC refers to the delivery point for the Taranaki combined cycle power station, Stratford 2 is the delivery point for the Stratford power station and Stratford 3 is the delivery point for the Ahuroa underground storage facility
- minimum operating pressure at delivery points:
  - KGTP: 35 barg
  - Other delivery points: 32 barg.
- delivery point growth and trend forecast consider recent data since FY17 for most delivery points
- The Taranaki combined cycle power station is anticipated to be closed by 2030.

Table E.6: Pipeline capacity forecast

Delivery Point	Aggregate contractual capacity (GJ/day)	Uncommitted operational capacity (GJ/day)		
		FY25	FY30	FY35
Ammonia-Urea Plant	0	40,866	40,866	40,866
Kaimiro	0	236,809	236,809	236,809
Kapuni	0	10,777	10,777	10,777
Kapuni Gas treatment plant	0	92,621	92,621	92,621
TCC, Stratford 2, Stratford 3	0	183,789	183,789	183,789

Maui pipeline capacity forecast

Our Maui pipeline is our largest pipeline and supplies gas north of Taranaki to our pipeline networks in Auckland, Bay of Plenty and central North. The following parameters and assumptions have been incorporated into the modelling:

- peak week was the week ending 08 October 2023
- 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 pipeline as it does on other pipelines. 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 peak period).
- minimum operating pressure at delivery points is 32 barg
- pipeline assumed running at a constant pressure of 46 barg at Oaonui production station
- Mokau compression is on and operating at 61 barg
- delivery point growth and trend forecast consider recent data since FY2017 for most delivery points.

Table E.7: Pipeline capacity forecast

Welded point	Delivery point	Peak demand (GJ/day)	Operational capacity (GJ/day)		
			FY25	FY30	FY35
Huntly Town Offtake	Huntly Town	172	214,370	214,374	214,380
Pirongia Offtake	Pirongia Te Awamutu DF	2,162	160,846	160,353	159,859
Otorohanga		18	229,981	246,236	98,460
Ngaruawahia Offtake	Ngaruawahia	15	251,011	265,213	195,983
Te Kuiti North Offtake	Te Kuiti North	93	2,685	2,683	2,681
Te Kuiti South Offtake	Te Kuiti South	672	8,191	8,182	8,172

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Welded point	Delivery point	Peak demand (GJ/day)	Operational capacity (GJ/day)		
			FY25	FY30	FY35
Oakura Offtake	Oakura	28	5,925	5,931	5,941
Mangorei Offtake	Mangorei	6,327	225,199	230,253	241,253
Rotowaro		82,848	317,375	323,781	301,384
Pokuru		29,269	313,482	323,774	344,794
Bertrand Road		48,408	263,534	272,235	292,515
Huntly Power Station		43,671	113,333	113,308	113,282

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E.5.5. Delivery point capacity forecasts

In general terms, overall network utilisation is decreasing, and we are confident, based on current operating pressures we currently foresee no material breaches in future demand and no requirement to plan any changes. Future operational changes (pressures) may drive changes as they are implemented.

The following tables forecast the capacity of delivery points across our pipeline networks.

Table E.8: North pipeline delivery point capacity forecast

Delivery point	Actual	Forecast						
	2024	2025	2030	2035	Capacity	Breach type	Equipment	Comments
Alfriston								Alfriston is closed
Bruce McClaren	2,540	2,578	2,578	2,578	2,500	minor breach	bath heater	
Drury 1	2,024	1,912	1,732	1,552	2,700	no breach	bath heater	
Flat Bush	2,154	2,223	2,086	1,948	6,590	no breach	meter	
Glenbrook	11,801	10,856	10,516	10,175		no breach	meter	
Harrisville 2	3,301	3,481	3,398	3,316	6,683	no breach	meter	
Henderson	7,120	6,750	4,550	2,349		no breach	bath heater	
Hunua (Vector + Nova Combined)	1,043	1,201	1,252	1,303	2,800	no breach	bath heater	
Hunua (Vector)	786	881	881	881	920	no breach	meter	
Hunua (Nova)	560	567	541	514	740	no breach	meter	
Hunua 3	950	931	933	936	3,680	no breach	meter	
Kauri DF	3,087	3,083	3,033	2,984	3,782	no breach	regulators	
Kingseat	8	8	7	6	50	no breach	no heater	JT cooling limits station capacity
Marsden 2	210	218	218	218	788	no breach	regulators	
Maungaturoto DF	2,490	2,488	2,492	2,496	3,300	no breach	bath heater	

Delivery point	Actual	Forecast						
	2024	2025	2030	2035	Capacity	Breach type	Equipment	Comments
Papakura	19,232	19,635	21,261	22,888	30,600	no breach	meter	
Pukekohe	687	677	696	715	705	minor breach	regulators	
Ramarama	302	297	273	249	380	no breach	meter	
Tuakau 2	3,278	3,144	2,544	1,943	12,300	no breach	bath heater	
Waikumete	8,107	8,049	6,684	5,318	18,720	no breach	meter	
Waitoki	2,071	2,984	3,121	3,259	3,900	no breach	bath heater	
Waiuku	435	415	373	332	1,331	no breach	regulators	
Warkworth 2	2,385	2,418	2,525	2,633	2,800	no breach	bath heater	
Wellsford					50	no breach	no heater	JT cooling limits station capacity
Westfield	39,106	43,273	44,088	44,904		no breach	meter	
Whangarei	1,163	1,174	1,247	1,320	1,393	no breach	regulators	

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Table E.9: Bay of Plenty pipeline delivery point capacity forecast

Delivery point	Actual	Forecast						
	2024	2025	2030	2035	Capacity	Breach type	Equipment	Comments
Broadlands	646	633	620	606	857	no breach	regulators	Broadlands heater removed from service in 2024
Edgecumbe	28	28	28	28	230	no breach	meter	
Edgecumbe DF	5,014	4,949	4,545	4,141	6,200	no breach	bath heater	
Gisborne	2,276	2,188	1,715	1,243	5,500	no breach	bath heater	
Kawerau (Tissue)	922	906	954	1,002	2,423	no breach	regulators	
Kawerau (Pulp & Paper)	2,164	2,122	2,105	2,088	4,846	no breach	regulators	
Kawerau	147	115	115	115	325	no breach	regulators	
Kihikihi	854	740	748	756	2,090	no breach	meter	
Kinleith (Pulp & Paper)	25,186	24,188	20,540	16,892	30,355	no breach	regulators	Possible closure of paper mill by mid-2025
Kinleith SS - shared equipment	25,201	24,192	20,499	16,805	38,800	no breach	bath heater	
Lichfield DF	3,049	2,957	3,068	3,178	4,970	no breach	meter	
Lichfield 2	4,375	4,442	4,482	4,521	8,120	no breach	meter	
Mt Maunganui	3,035	3,026	2,850	2,675	4,680	no breach	meter	
Opotiki	115	151	137	122	850	no breach	meter	
Papamoa	984	995	1,030	1,066	3,881	no breach	filter	
Putaruru	238	66	-	-	770	no breach	bath heater	
Pyes Pa	1,033	1,097	1,341	1,585	1,790	no breach	meter	

Delivery point	Actual 2024	Forecast 2025	2030	2035	Capacity	Breach type	Equipment	Comments
Rangiuru	531	550	563	576	1,104	no breach	regulators	
Reporoa	3,423	3,587	3,474	3,361	4,031	no breach	filter	
Reporoa Dairy Factory	2,319	2,443	2,378	2,314	6,700	no breach	meter	
Reporoa Town	60	60	60	60	1,650	no breach	meter	
Rotorua	2,802	2,757	2,275	1,794	5,600	no breach	bath heater	
Taupo	1,582	1,454	1,608	1,763	1,736	minor breach	filter	
Tauranga	1,407	1,412	1,112	811	2,580	no breach	meter	
Tauriko	2,889	2,889	2,890	2,891	7,960	no breach	meter	Tauriko is a new station and there is little historic flow. Predicted flow based on current maximum flow that has occurred
Te Puke - 2nd cut to DRS	452	565	643	720	900	no breach	meter	
Te Teko					147	no breach	regulators	
Tirau	57	58	61	63	331	no breach	regulators	
Tirau DF	1,698	1,604	1,148	693	4,000	no breach	bath heater	
Tokoroa	1,232	1,327	1,345	1,362	2,590	no breach	meter	
Waikeria	335	335	335	335	672	no breach	regulators	
Whakatane	4,307	3,983	3,849	3,716	5,800	no breach	bath heater	

Table E.10: Central North pipeline delivery point capacity forecast

Delivery point	Actual	Forecast						
	2024	2025	2030	2035	Capacity	Breach type	Equipment	Comments
Te Rapa	10,150	10,152	10,174	10,197	11,700	no breach	bath heater	
Hamilton Temple View	8,500	7,803	6,542	5,280	10,800	no breach	meter	
Cambridge	2,980	3,399	3,399	3,399	4,310	no breach	meter	
Hamilton Te Kowhai	4,819	5,085	5,005	4,925	10,780	no breach	meter	
Waitoa	2,481	2,766	2,766	2,766	5,309	no breach	regulators	
Kiwitahi 1 (Peroxide)	1,235	1,176	1,172	1,167	3,300	no breach	bath heater	
Kiwitahi 2	157	176	184	192	3,300	no breach	bath heater	
Tatuanui	1,924	2,040	2,106	2,173	3,400	no breach	bath heater	
Morrinsville SS - shared equipment	2,083	2,050	1,868	1,686	3,800	no breach	bath heater	
Morrinsville dairy factory	1,875	1,987	2,068	2,150	4,110	no breach	meter	
Horotiu	2,757	2,757	2,757	2,757	4,310	no breach	meter	
Morrinsville	466	470	485	500	1,440	no breach	meter	
Matangi	15	16	14	12	50	no breach	no heater	JT cooling limits station capacity

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Table E.11: Central South pipeline delivery point capacity forecast

DELIVERY POINT	ACTUAL	FORECAST						
	2024	2025	2030	2035	CAPACITY	BREACH TYPE	EQUIPMENT	COMMENTS
New Plymouth	5,734	6,074	5,813	5,552	7,800	no breach	heater	
Eltham	992	992	1,047	1,102	1,456	no breach	regulators	
Waitara	733	727	672	616	1,130	no breach	regulators	
Stratford	580	603	603	603	891	no breach	regulators	
Inglewood	334	335	291	246	384	no breach	regulators	
Kaponga	17	16	13	10	50	no breach	no heater	JT cooling limits station capacity

Table E.12: South pipeline delivery point capacity forecast

Delivery point	Actual	Forecast						
	2024	2025	2030	2035	Capacity	Breach type	Equipment	Comments
Ashurst	135	135	135	135	137	no breach	bath heater	
Belmont	11,460	11,221	9,694	8,166	15,000	no breach	bath heater	
Dannevirke	450	521	521	521	501	minor breach	regulators	
Feilding	1,515	1,373	1,085	797	3,600	no breach	bath heater	
Flockhouse	-	-	-	-	50	no breach	no heater	JT cooling limits station capacity
Foxton	313	303	297	291	554	no breach	regulators	
Hastings	11,180	11,185	11,206	11,227	17,320	no breach	meter	
Hastings (Nova)	1,080	961	780	598	4,450	no breach	meter	
Hawera	2,416	2,980	3,238	3,496	6,200	no breach	bath heater	
Hawera (Nova)	496	504	487	469	990	no breach	meter	
Kairanga	35	45	-	-	50	no breach	no heater	JT cooling limits station capacity. Low temperature breaches occur for a short duration that does not cause a concern for the customer. Piping is not at risk as temperatures do not go too low
Kaitoke	145	148	147	145	166	no breach	bath heater	
Kakariki	481	485	488	491	710	no breach	meter	
Kuku	-	-	-	-	50	no breach	no heater	JT cooling limits station capacity
Lake Alice	278	296	305	313	318	no breach	regulators	
Levin	1,583	1,756	1,514	1,272	2,597	no breach	meter	

Delivery point	Actual	Forecast						
	2024	2025	2030	2035	Capacity	Breach type	Equipment	Comments
Longburn	1,027	1,065	1,099	1,133	2,700	no breach	regulators	
Mangaroa	146	132	122	112	180	no breach	meter	
Marton	1,179	1,175	1,120	1,065	2,800	no breach	bath heater	
Matapu	-	-	-	-	50	no breach	no heater	JT cooling limits station capacity
Manaia	86	104	74	43	219	no breach	regulators	
Oroua Downs	252	248	232	216	330	no breach	meter	
Otaki	171	173	161	148	652	no breach	regulators	
Pahiatua DF	3,865	3,838	3,720	3,601	4,605	no breach	meter	
Pahiatua	63	65	46	27	610	no breach	meter	
Palmerston North	6,910	6,757	5,679	4,601	8,502	no breach	regulators	
Paraparaumu	934	879	603	326	1,560	no breach	pipework	
Patea	233	211	197	184	300	no breach	bath heater	
Pauatahanui 1	985	997	1,025	1,053	2,329	no breach	regulators	
Pauatahanui 2	5	5	5	5	50	no breach	no heater	JT cooling limits station capacity
Takapau	623	613	571	529	827	no breach	regulators	
Tawa B	2,075	2,029	1,637	1,244	5,490	no breach	pipework	
Te Horo	12	12	8	4	50	no breach	no heater	JT cooling limits station capacity
Waikanae 2	1,073	1,042	901	759	2,647	no breach	regulators	
Waitangirua (Wellington) / Tawa A	19,795	19,144	17,410	15,676	27,000	no breach	bath heater	

Delivery point	Actual	Forecast						
	2024	2025	2030	2035	Capacity	Breach type	Equipment	Comments
Waitangirua (Porirua)	3,068	3,088	3,047	3,007	4,550	no breach	meter	
Waitotara	245	238	204	171	325	no breach	regulators	
Whanganui	5,711	5,796	5,661	5,525	7,400	no breach	bath heater	
Waverley	5	5	2		50	no breach	no heater	JT cooling limits station capacity

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Table E.13: Frankley Road pipeline delivery point capacity forecast

Delivery point	Actual	Forecast						
	2024	2025	2030	2035	Capacity	Breach type	Equipment	Comments
TCC	63,088	65,715	64,007	62,300	n/a	no breach	n/a	Shutdown of TCC expected sometime after 2025
Stratford 2	25,208	34,717	23,479	12,240	n/a	no breach	n/a	
Stratford 3 Delivery	74,568	75,843	78,579	81,316	n/a	n/a	n/a	
Ammonia Urea (Fuel)	11,532	10,861	11,321	11,781	15,657	no breach	regulators	
Ammonia Urea (Process)	14,849	13,866	14,880	15,894	15,657	minor breach	regulators	
Kapuni (Lactose)	186	185	168	152	353	no breach	regulators	

Table E.14: Maui pipeline minor offtakes delivery point capacity forecast

Delivery point	Actual	Forecast						
	2024	2025	2030	2035	Capacity	Breach type	Equipment	Comments
Huntly Town	304	326	328	330	840	no breach	regulators	
Pirongia	22	22	19	16	50	no breach	no heater	JT cooling limits station capacity
Te Awamutu North	308	223	15		860	no breach	meter	
Te Awamutu DF	4,819	4,819	4,819	4,819	7,500	no breach	meter	
Otorohanga	114	111	89	68	220	no breach	meter	
Ngaruawahia	77	81	93	105	129	no breach	regulators	
Te Kuiti North	387	387	387	387	938	no breach	regulators	
Te Kuiti South	969	931	882	834	1,909	no breach	regulators	
Oakura	176	170	196	221	210	no breach	meter	
Opunake	88	90	90	90	241	no breach	regulators	
Okato	36	38	31	25	133	no breach	regulators	
Pungarehu No.2	23	18	24	29	50	no breach	no heater	JT cooling limits station capacity

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Table E.15: Maui pipeline delivery point capacity forecast

Delivery point	Actual	Forecast						
	2024	2025	2030	2035	Capacity	Breach type	Equipment	Comments
Bertrand Road	6,956				n/a	n/a	n/a	This is an offtake pipe and supplies fuel gas to Methanex' Motunui plant via Faull Road and the 033 line.
Ngatimaru Road	125,384	136,993	128,698	120,403	n/a	n/a	n/a	Pohokura Gas Tie In (receipt point) Does not need to be included in the AMP for capacity
Huntly Power station	120,400	144,911	130,337	115,763	269,946	no breach	filter	
Mangorei	26,104	25,949	26,318	26,687	71,969	no breach	filter	

E.6. Schematic diagrams of transmission network

This section contains seven schematic diagrams of our pipeline network:

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

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

Figure E.2: North network

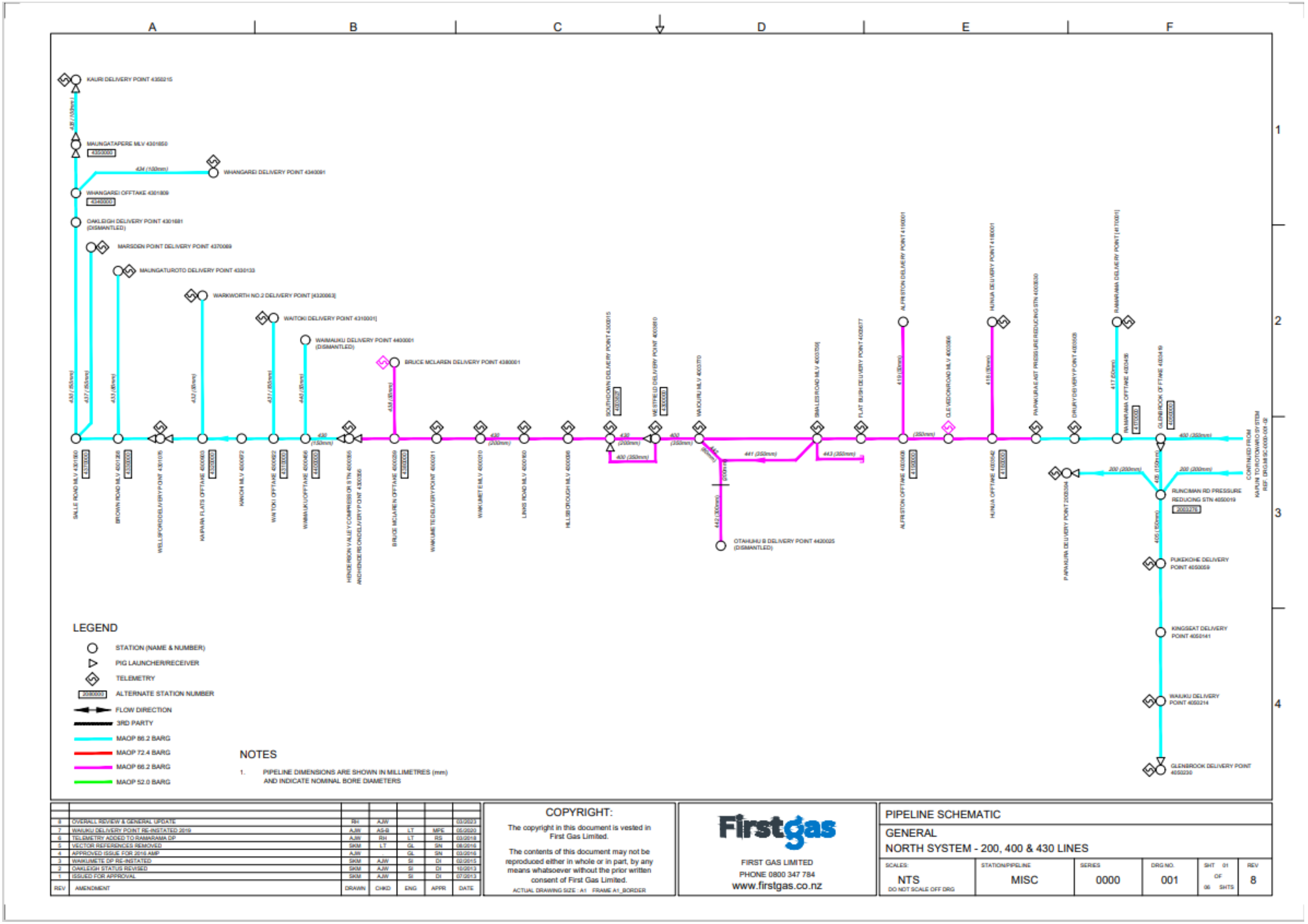

Figure E.3: Bay of Plenty network

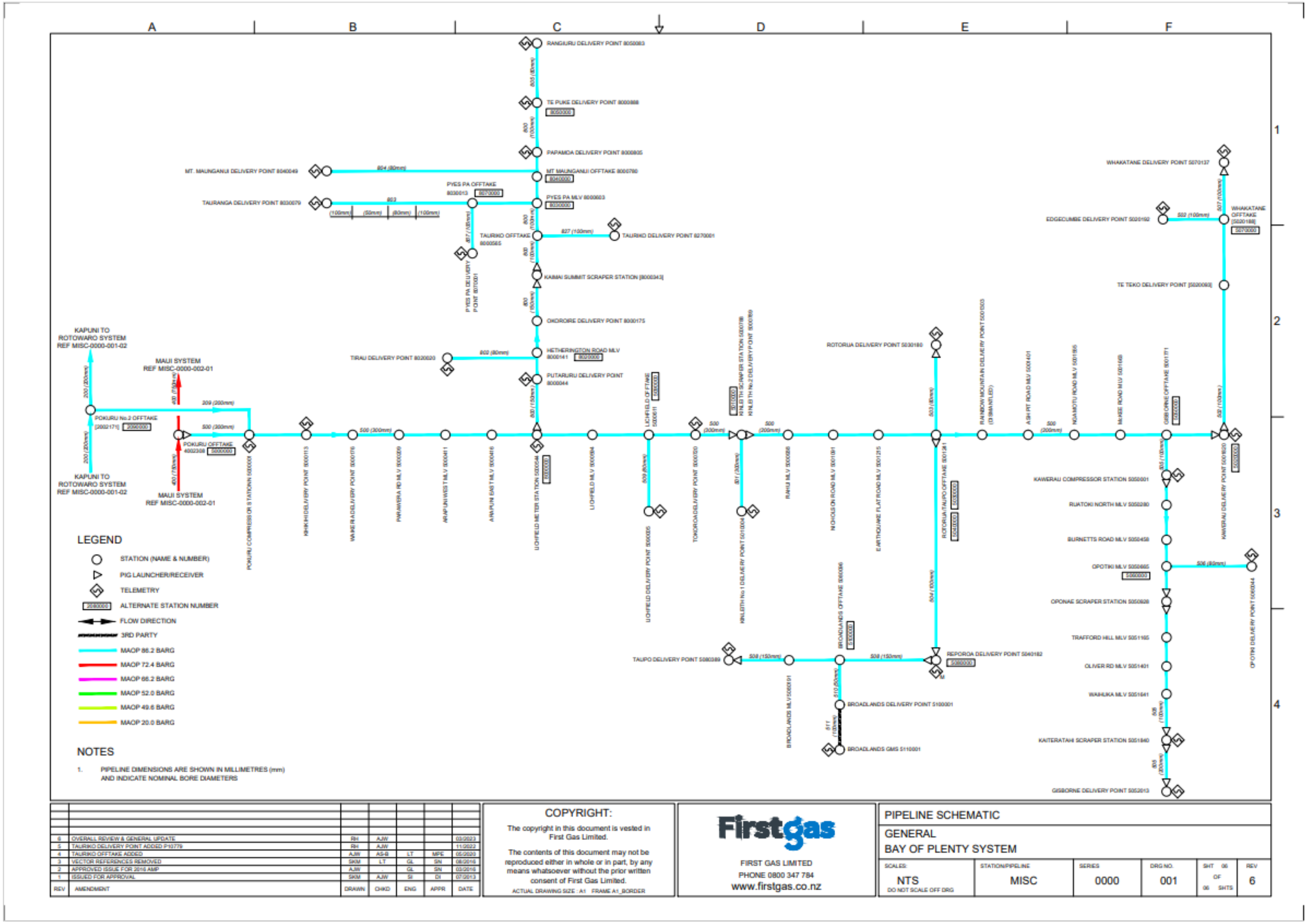

Figure E.4: Kapuni to Rotowaro and Morrinsville

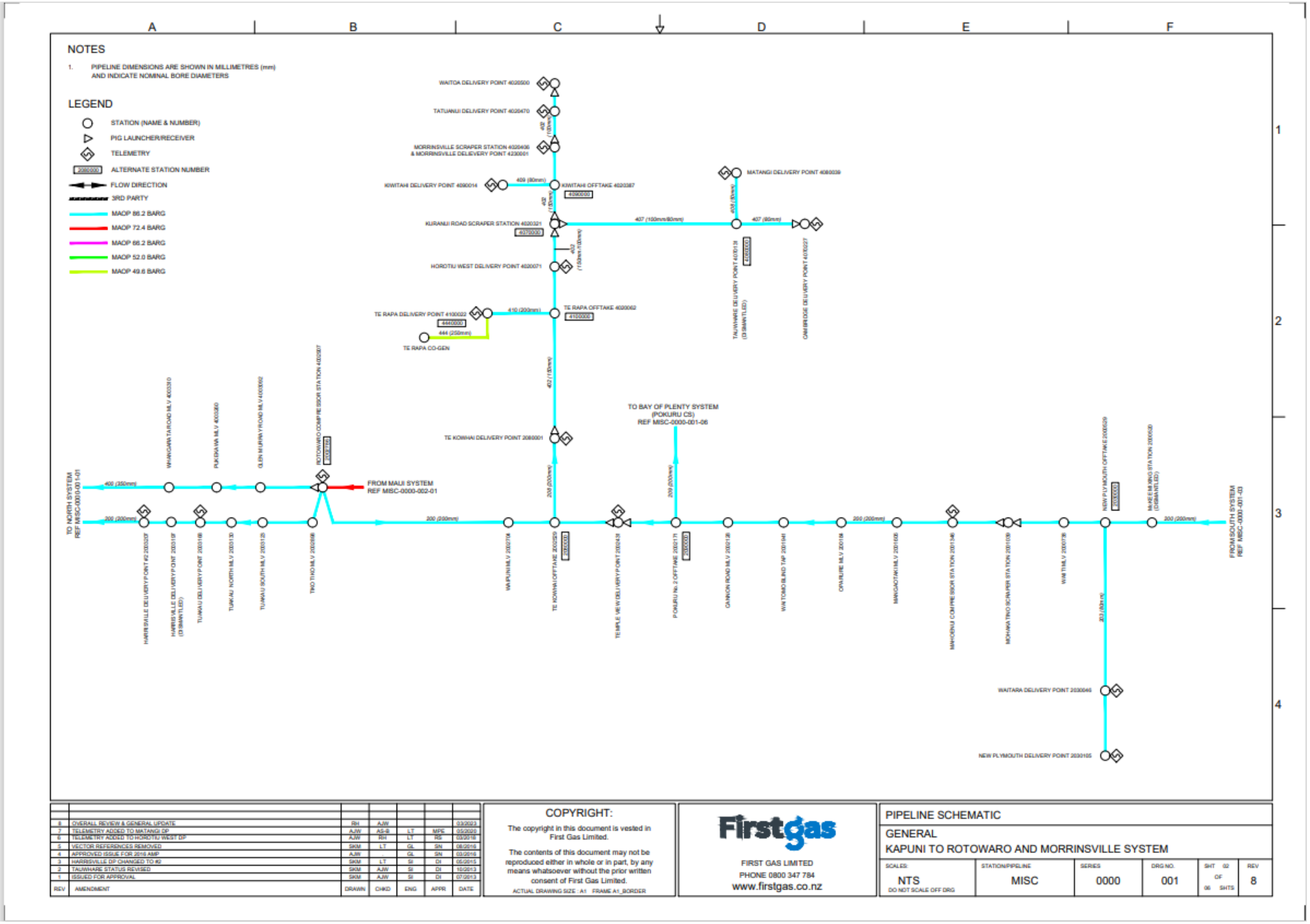

Figure E.5: South network 1

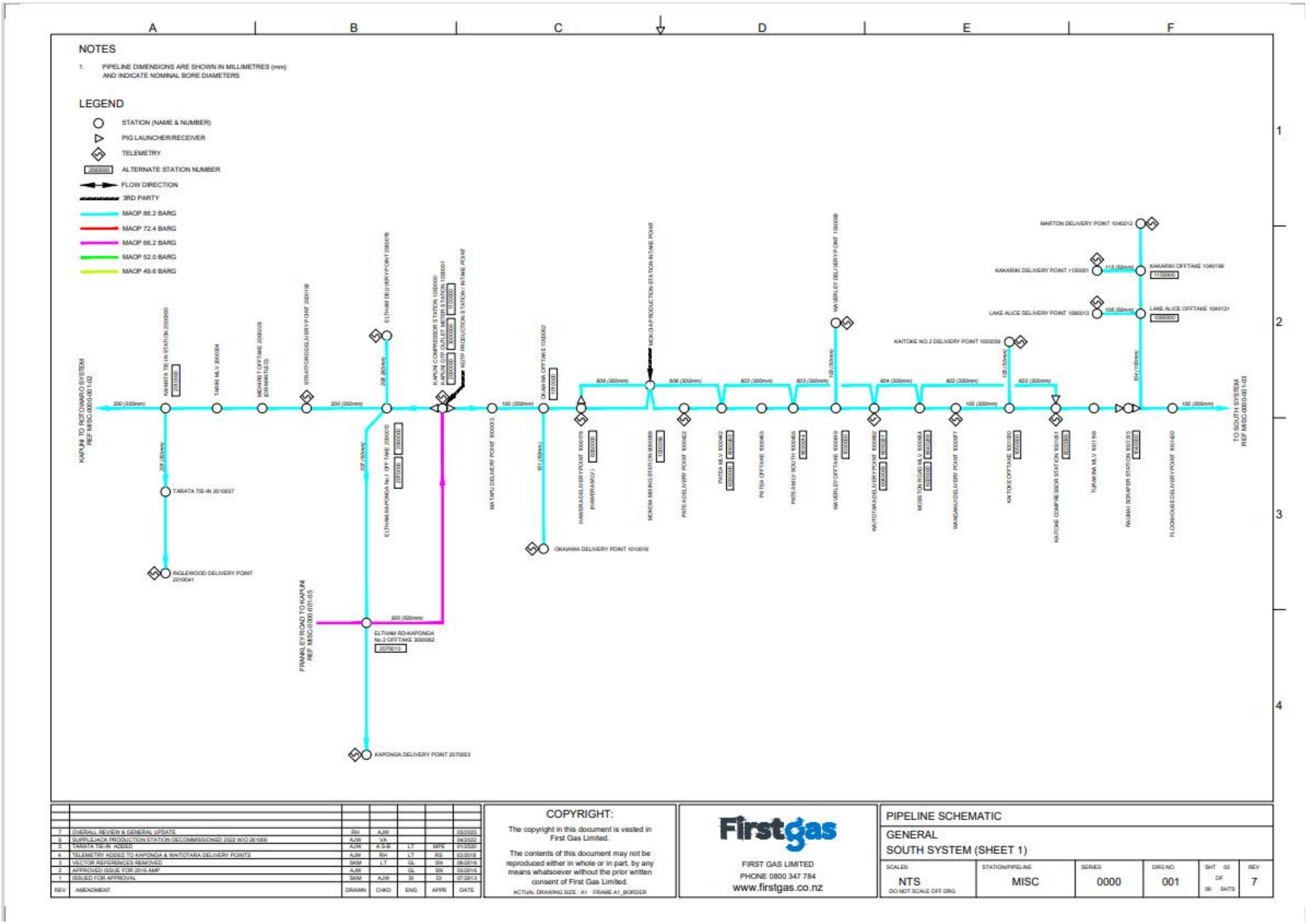

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Figure E.6: South network 2

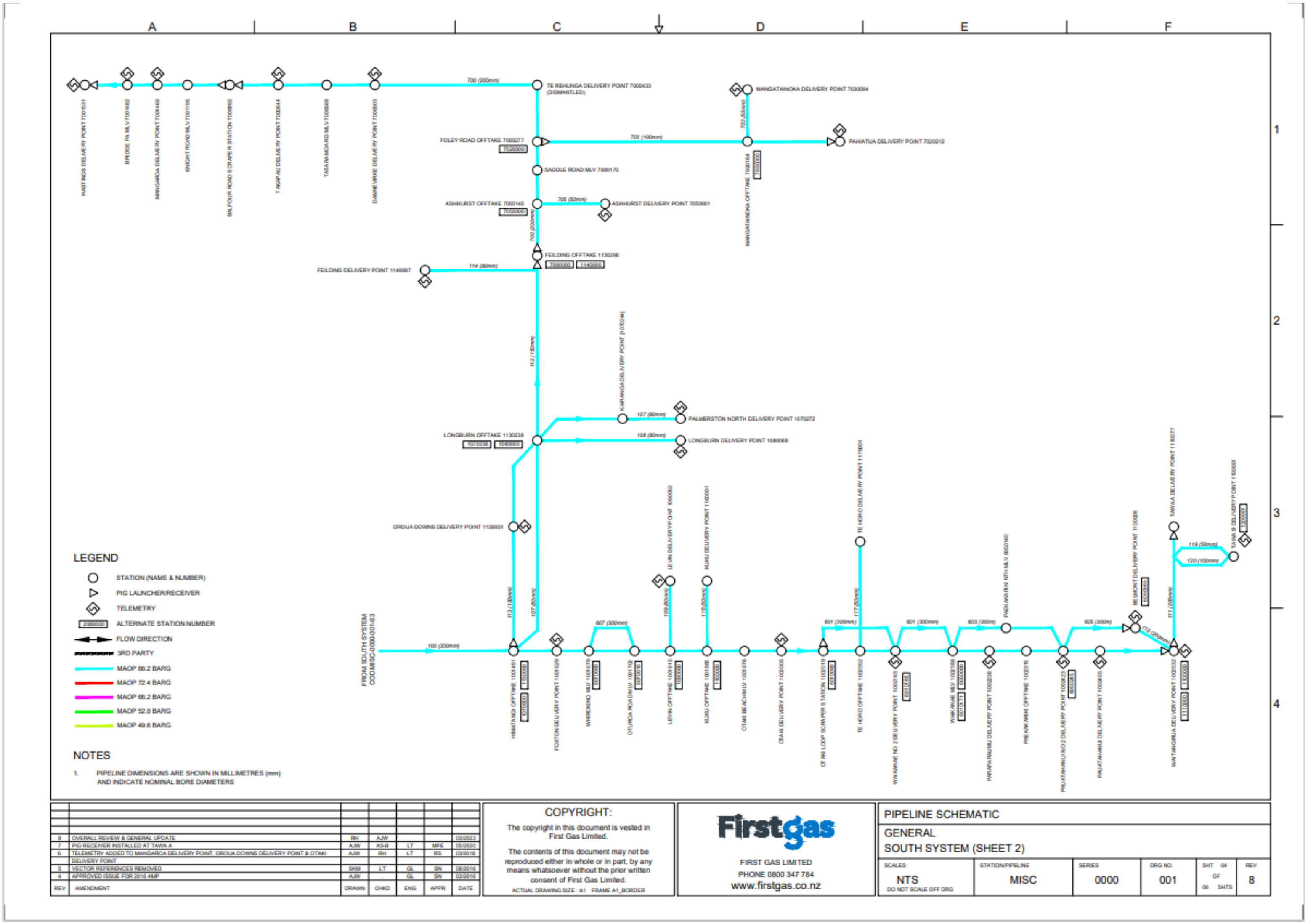


Figure E.7: Frankley road network

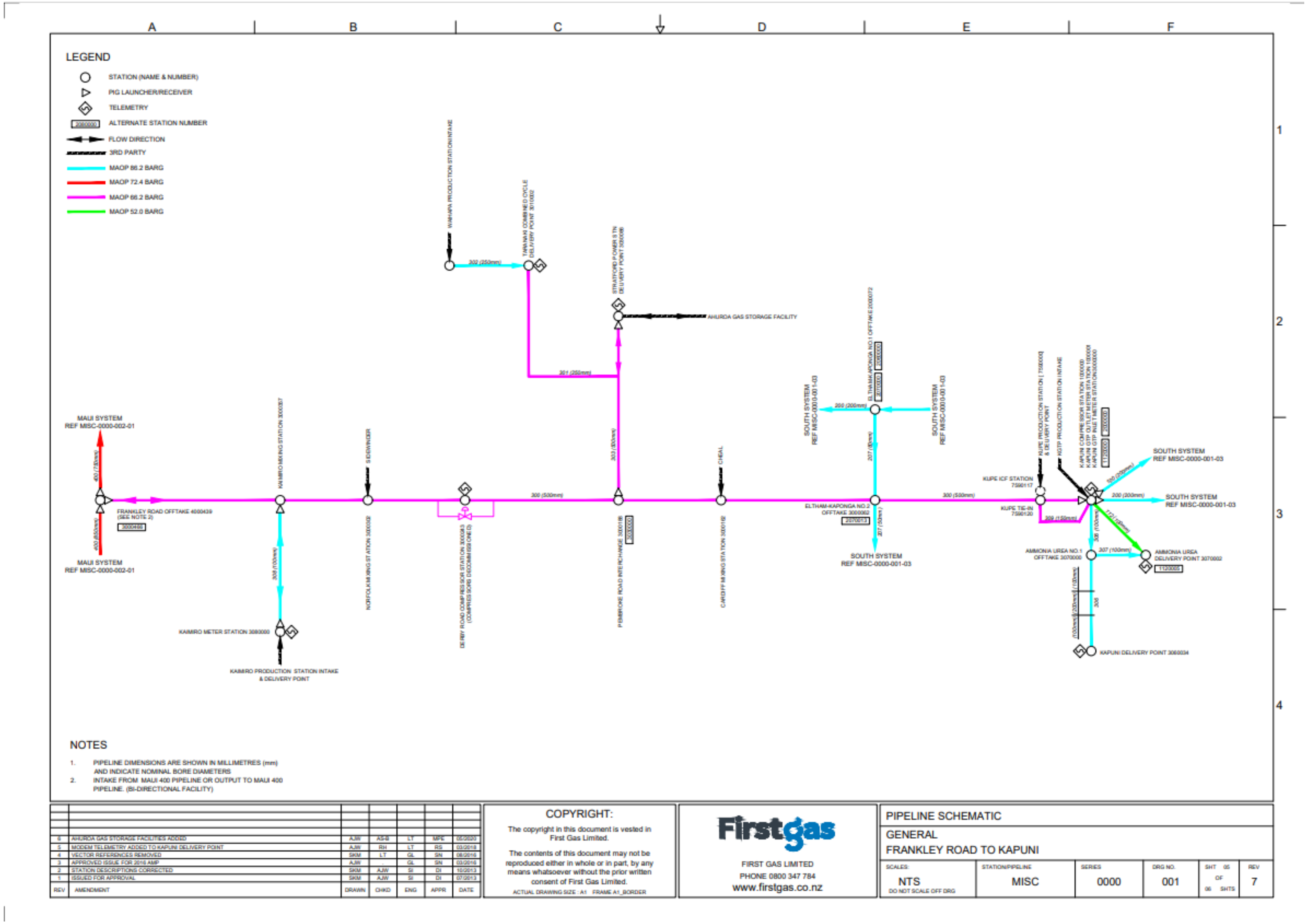
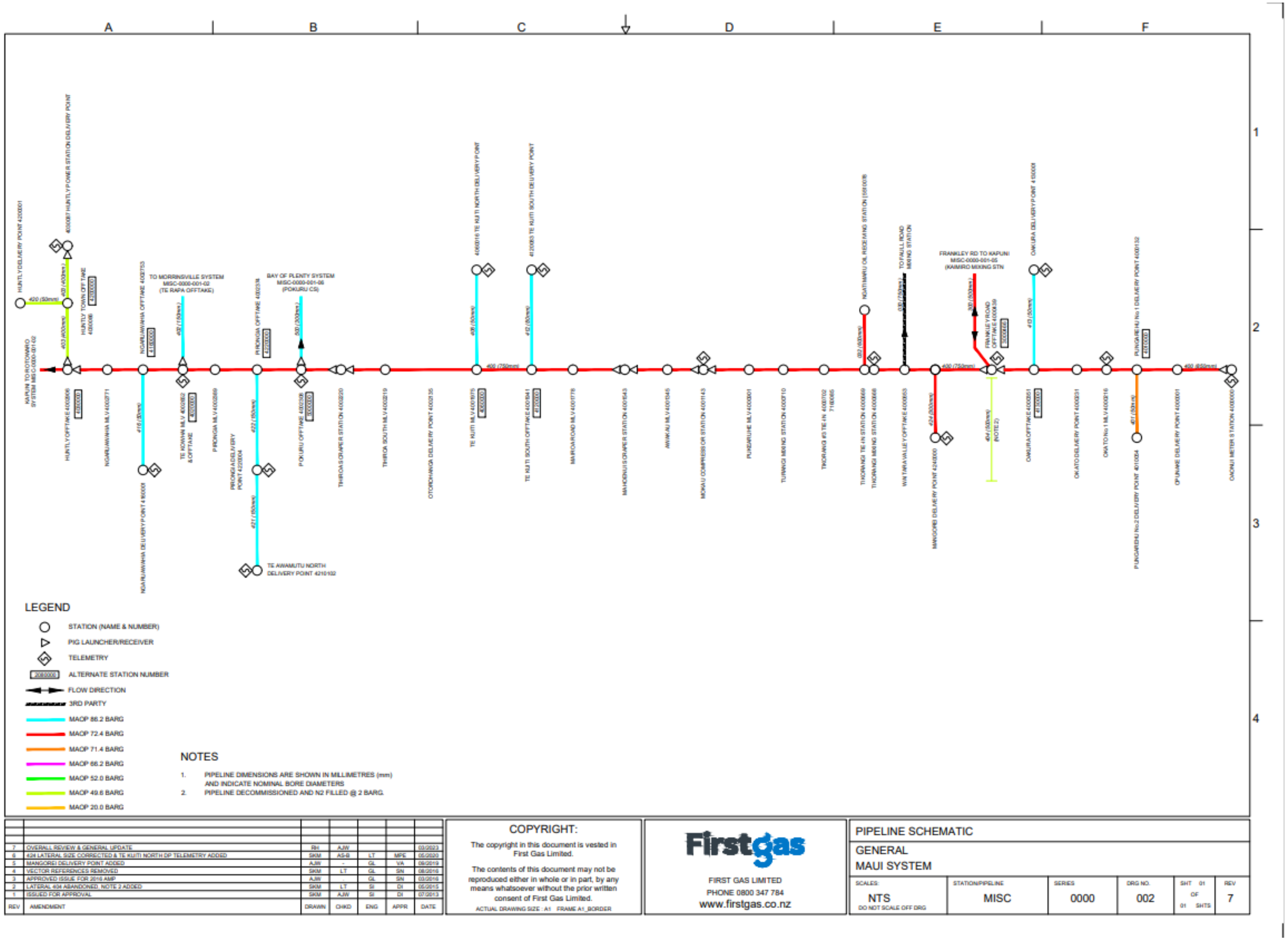


Figure E.8: Maui network



Appendix F. COMPLIANCE SCHEDULE

This table provides a look-up reference for each of the information disclosure requirements described in the Gas Transmission Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024, including attachments and schedules.

REGULATORY REQUIREMENTS		AMP REFERENCE
2.6	ASSET MANAGEMENT PLANS AND FORECAST INFORMATION	AMP section where compliance addressed
2.6.1	Subject to clauses 2.6.3, before the start of each disclosure year, every GTB must: (1) Complete an AMP that: (a) relates to the gas transmission services supplied by the GTB. (b) meets the purposes of AMP disclosure set out in clause 2.6.2. (c) has been prepared in accordance with Attachment A to the Gas Transmission Information Disclosure Determination document. (d) contains the information set out in the schedules described in clause 2.6.6. (e) contains the Report on Asset Management Maturity as described in Schedule 13.	An AMP has been completed, such that: (a) The AMP Summary Document describes the purpose of the AMP and how the AMP relates to the Firstgas gas transmission system network. (b), (c) Compliance with Clause 2.6.2 and Attachment A is summarised in this table. (d) The schedules required in clause 2.6.6 are included in Appendix B. (e) AMMAT report (Schedule 13) is included in Appendix B.
	(2) Complete the Report on Asset Management Maturity in accordance with the requirements specified in Schedule 13; and	The AMMAT report (Schedule 13) is included in Appendix B.
	(3) Publicly disclose the AMP.	The AMP is publicly available on the Firstgas website www.firstgas.co.nz
2.6.2	The purposes of AMP disclosure referred to in subclause 2.6.1(1)(b) are that the AMP- (1) 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.	(1) (a) to (c): • the AMP, including Appendix D, explains how assets are being managed over their lifecycle for the long-term • performance measures and targets are included in Appendix C • expenditure governance and cost management are discussed in Appendix C.

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Regulatory requirements		AMP reference
	(2) Must be capable of being understood by interested persons with a reasonable understanding of the management of infrastructure assets	The AMP has been structured and presented in a way that is intended to be easily understood by interested persons. This includes: • technical details are located in appendices leaving the AMP Summary to deliver core messages • inclusion of a glossary in Appendix A • clear description of expenditure forecasts presented in the AMP.
	(3) Should provide a sound basis for the ongoing assessment of asset-related risks, particularly high impact asset-related risks.	Risk management policy and framework are discussed in Appendix C. Asset-related risks are discussed in Appendix D.
2.6.3	Subject to clause 2.6.4, a GTB may elect to complete and publicly disclose an AMP update, as described in clause 2.6.5, before the start of a disclosure year, instead of an AMP, as described in clause 2.6.1(1), unless the start of that disclosure year is- (1) for a five-year regulatory period (a) one year after the start of the DPP regulatory period; or (b) two years before the start of the next DPP regulatory period. (2) for a four-year regulatory period (a) one year after the start of the DPP regulatory period; or (b) one year before the start of the next DPP regulatory period.	Firstgas has published a full AMP for RY25.
2.6.4	A GTB must not complete and publicly disclose an AMP update instead of an AMP if it has not previously publicly disclosed an AMP under clause 2.6.1.	Firstgas has published a full AMP for RY25.
2.6.5	For the purpose of clause 2.6.3, the AMP update must- (1) Relate to the gas transmission services supplied by the GTB (2) Identify any material changes to the network development plans disclosed in the last AMP under clause 14 of Attachment A or in the last AMP update disclosed under this clause (3) Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP pursuant to clause 15 of Attachment A or in the last AMP update disclosed under this clause (4) Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b	Firstgas has published a full AMP for RY25.

REGULATORY REQUIREMENTS		AMP REFERENCE
	(5) Provide an assessment of transmission capacity as set out in clause 8 of Attachment A (6) Identify any material changes related to the legislative requirements as set out in clause 3.6 of Attachment A (7) Identify any changes to the asset management practices of the GTB that would affect a Schedule 13 Report on Asset Management Maturity disclosure; and (8) Contain the information set out in the schedules described in clause 2.6.6.	
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	These reports are included in Appendix B.

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<table>
<tr><th colspan="2">Attachment A: Asset Management Plans</th><th>AMP Reference</th></tr>
<tr><td colspan="3">This attachment sets out the mandatory disclosure requirements with respect to AMPs. The text in italics provides a commentary on those requirements. The purpose of the commentary is to provide guidance on the expected content of disclosed AMPs. The commentary has been prepared on the basis that GTBs will implement best practice asset management processes.</td></tr>
<tr><td colspan="2">AMP Design</td><td></td></tr>
<tr><td>1</td><td>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.</td><td>1.1 Section C.4 sets out performance measures / targets
1.2 Section C.3.1 discusses this
1.3 Alignment with corporate vision and strategy is explained in Appendix C
1.4 Section C.4.
1.5 Section C.3.2 discusses this
1.6 Appendices D and E reflect this
1.7 Appendix E discusses this
1.8 Appendix D.
1.9 As relevant, these are discussed in planned solutions in Appendix D</td></tr>
<tr><td>2</td><td>The disclosure requirements are designed to produce AMPs that-
2.1 are based on, but 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</td><td>2.1 The elements identified in clause 1 are described above.
2.2 AMP is distributed to major stakeholders and 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 Asset management practices and assessment against ISO 55000 principles are described in Appendix C
2.4 Performance measures and target levels are defined in Section C.4
2.5 Our approach to risk management is discussed in Appendix C. Appendix D considers asset risk more specifically.
2.6 The delivery model, including resourcing, is included in Appendix C.
2.7 The organisational structure is set out in the AMP Summary.</td></tr>
</table>

Attachment A: Asset Management Plans		AMP Reference
	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; and 2.11 Promote continual improvements to asset management practices.	2.8 Section C.3 outlines competency and training requirements. 2.9 Asset management systems, integration and information management are outlined in Section C.3.4. 2.10 Throughout the AMP terminology and definitions have been used that are consistent with those used in the glossary (Attachment A). 2.11 Section C.3 discusses asset management competency.
Contents of the AMP		
3.1	The AMP must include the following- 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
3.2	Details of the background and objectives of the GTB's asset management and planning processes.	The asset management framework and policy are described in Appendix C. This includes asset management strategy, 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; and 3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans.	3.3.1 The purpose of the AMP is set out in Chapter 1 3.3.2 our corporate mission or vision is set out in the AMP summary document 3.3.3 the outputs of the business planning process is discussed in Appendix C 3.3.4 the asset management document hierarchy is included in Appendix C 3.3.5 line-of-sight between the objectives of the AMP and other corporate goals is included in Appendix C

Attachment A: Asset Management Plans		AMP Reference
3.4	The purpose statement should be consistent with the GTB's vision and mission statements and show a clear recognition of stakeholder interest. 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 executive summary outlines our corporate mission and vision within the context of asset management. Section 1.3 of the AMP Summary document identifies the 10-year period covered by the AMP. This is defined as the "planning period".
3.5	Good asset management practice recognises the greater accuracy of short-to- medium term planning and will allow for this in the AMP. The asset management planning information for the second 5 years of the AMP planning period need not be presented in the same detail as the first 5 years. The date that it was approved by the directors	The AMP approval date by Directors is provided in Section 1 of the AMP Summary Document and in the Director's certificate in Appendix G.
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; and 3.6.2 the impact on asset management.	Section C.5.3 sets out key legislation, regulations, and industry codes affecting asset management. Appendix D explains how they impact our asset management.
3.7	A description of stakeholder interests (owners, consumers, etc.) which identifies important stakeholders and indicates- 3.7.1 how the interests of stakeholders are identified 3.7.2 what these interests are 3.7.3 how these interests are accommodated in asset management practices; and 3.7.4 how conflicting interests are managed.	The AMP Summary document describes how the needs and interests of all stakeholders are identified, and how conflicting interests are managed. Other sections discuss stakeholders as relevant.
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; and 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 C.3.2 describes our approach to asset management governance and the respective roles within the business.

Attachment A: Asset Management Plans		AMP Reference
3.9	All significant assumptions- 3.9.1 quantified where possible 3.9.2 clearly identified in a manner that makes their significance understandable to interested persons, and including – a description of changes proposed where the information is not based on the GTB's existing business – the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and – the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Forecast on Operational Expenditure set out in Schedule 11b.	Key assumptions for the development of the AMP are outlined in Section C.1.2. Expenditure assumptions are outlined in Section 4 of the AMP summary document. • Assumptions around escalation are included in Schedule 14a
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 3 of the AMP summary addresses factors that may lead to material differences between the prospective information and the actual outcomes reported in future disclosures.
3.11	An overview of asset management strategy and delivery. To support the Report on Asset Management Maturity disclosure and assist interested persons to assess the maturity of asset management strategy and delivery, the AMP should identify – 1 how the asset management strategy is consistent with the GTB's other strategy and policies 2 how the asset strategy considers the life cycle of the assets 3 the link between the asset management strategy and the AMP 4 processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.	Appendix C explains Firstgas's approach to asset management, including how the how the framework relates to corporate objectives through the asset management policy and our KPIs. Appendix D explains our approach to asset lifecycle management.
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.	Section C.3.4 provides an overview of system and information data, including relationships of asset management data, and the systems used to manage it and the degree of system integration.

Attachment A: Asset Management Plans		AMP Reference
	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.	
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.	Section C.3.1 describes the asset management improvement programme. Section C.3.4 identifies data limitations and details the initiatives underway 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.	Our approach to maintenance is discussed in Section D.1.2, with asset specific information in relevant sections. Our approach to planning and implementing network development projects is discussed in Appendix E. Section C.4 sets out details on performance measures and related processes.
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 GTB 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.	Documentation, controls, and review processes are outlined in Appendix C, with examples of relevant material in other sections. In particular: • Section C.1 discusses our asset management documentation and related linkages. • Section D.1.4. explains our delivery model • Section C.1.3 discusses reviews of our asset management system

Attachment A: Asset Management Plans		AMP Reference
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; and 2 demonstrate staff engagement in the efficient and cost-effective delivery of the asset management requirements.	Section 2.4 of the AMP summary document provides an overview of how asset management strategies and plans are communicated to key stakeholders. Appendices C and D provide further details on communication processes with internal and external stakeholders, including contractors and consultants. Staff engagement in the development and delivery of the AMP is referenced throughout the document.
4	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise.	All expenditure figures are presented in constant FY25 New Zealand dollars, as confirmed in Section 4 of the AMP summary document.
5	The AMP must be structured and presented in a way that the GTB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	The AMP has been structured and presented in a manner intended to simplify the presentation of information relevant to the disclosure. The AMP Summary document can be read as a standalone document to provide a summarised view. The appendices provide greater detail on the plans at an asset fleet level and our approach to asset management.
Assets Covered		
6	The AMP must provide details of the assets covered, including- 6.1 A high-level map indicating the geographic location of the network; and	A map of the high-pressure transmission pipelines is provided in Section 2.2 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; and (d) the distance between the items referred to in subclause 6.2.1(c) of this attachment; and 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	Section E.6 provides schematics of the transmission network showing the required details. 6.2.2 There have been no significant network changes since previous disclosure.

Attachment A: Asset Management Plans		AMP Reference
	(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; and (c) a description of the change.	
6.3	The AMP must describe the network assets by providing the following information for each asset category-	Appendix D addresses these requirements
6.4	Description and quantity of assets	An overview of asset quantities is provided in Section D.2.2.
6.5	Age profiles; and	Age profile graphs are provided for asset categories
6.6	A discussion of the condition of the assets, further broken down into more detailed categories as appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	Appendix D provides detail on asset condition, including systemic issues and their impact on asset lifecycle planning.
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); and 7.2 assets owned by the GTB but installed at facilities owned by others.	The asset categories in Appendix D include those 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.	An assessment of system capacity, based on forecast demand and aligned with our investment plans is provided in Appendix E.
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; and 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.	Detailed station and offtake capacity analysis is provided in Section E.5.
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-	The available capacity of each offtake point is assessed in Section E.5. The analysis includes: 8.2.1 – Actual throughput during a recent system peak flow period.

Attachment A: Asset Management Plans		AMP Reference
	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.	8.2.2 – Forecast trends and modelled behaviours such as load growth and peak demand factors.
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; and 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 included in section E.5. This includes confirming the software (Synergi) and version (4.9.4) used for the modelling. Recent system peak flows are published on the website: www.firstgas.co.nz.
8.4	If the analysis specified in clause 8.1.1 of this attachment is posted on a website normally used by the GTB for the publication of information and can be readily accessed at no charge by interested persons, the analysis may be incorporated in the AMP by reference subject to the information being retained on such a website for a period of not less than five years	The AMP is posted on the Firstgas website: www.firstgas.co.nz/about-us/regulatory-information/transmission
Service Levels		
9	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	The AMP summary document describes key performance indicators, results for 2024 and target for coming year. Section C.4 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.	The AMP Summary Document - Section 3.4 Performance of the transmission network includes DPP requirements. Appendix C – Asset management approach provides further detail and information on performance measures and targets, including: Consumer-oriented performance measure with differentiation between consumer types.

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Attachment A: Asset Management Plans		AMP Reference
	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.	Indicators of asset performance, efficiency and service effectiveness, including technical and financial metrics.
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 C – Asset management approach describes the performance targets, which are based on historical trends, regulatory requirements, consumer expectations, and network capability.
12	Targets should be compared to historic values where available to provide context and scale to the reader.	Historical performance values are provided in Section C.4 – Performance Measures, allowing comparison against targets to give context and scale.
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.
Network Development planning		
14	AMPs must provide a detailed description of network development plans, including-	Network development plans are outlined in Appendix E.
14.1	A description of the planning criteria and assumptions for network development. Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated, and the methodology briefly described.	The network developments and planning criteria methodology is provided in the Appendix E.
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.; and 2 the approach used to identify standard designs.	Section C.5 discusses the extent to which standard designs are feasible for the transmission network. Where relevant we set out approaches to using standard designs in Appendix D.
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.	Capacity criteria and demand modelling for new equipment are outlined in the Section E.5.
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.	The process for prioritising network development projects is described in Section E.4. 14.4.1 Demand forecasts tables are provided in Section E.5, including constraints as relevant.

Attachment A: Asset Management Plans		AMP Reference
	14.4.1 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand 14.4.2 Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates 14.4.3 Provide separate forecasts to at least off-take points covering at least a minimum 5-year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are considered in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts; and 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 criteria described should relate to the GTB's philosophy in managing planning risks.	14.4.2. The load forecasting methodology is outlined in Appendix E.5. 14.4.3. Delivery point forecasts are included in Section E.5. 14.4.4. Section E.5 sets out applicable constraints during the AMP planning period.
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 5 years; and 14.5.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	Appendix E provides detail on development options, including the reasons for selected solutions, alternative options considered, and planned innovations aimed at improving efficiency, extending asset life, and deferring investment.
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 4 years (where known); and 14.6.3 an overview of the material projects being considered for the remainder of the AMP planning period. For projects included in the AMP where decisions have been made, the reasons for choosing the selected option should be stated which should include how target levels of service will be impacted. For other projects planned to start in the next 5 years, alternative options should be discussed.	The AMP summary document discusses overall forecasts, including those relating to network development. Further details on planned works and their timings are set in Appendix E.

Attachment A: Asset Management Plans		AMP Reference
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.	Section E.5 outlines how network development plans align with current gas demand forecasts, taking into account inputs from the Gas Industry Company and Government agencies.
Lifecycle asset management planning (maintenance and renewal)		
15	The AMP must provide a detailed description of the lifecycle asset management processes, including-	The overall lifecycle asset management approach is set out in Appendix D.
15.1	The key drivers for maintenance planning and assumptions.	The key drivers for asset maintenance are discussed in Section D.1.2, with asset specific details provided throughout Sections D.3 to D.7.
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; and 15.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period.	Maintenance and inspection programmes for each asset category are outlined in Appendix D. This includes - 15.2.1 Routine inspection and maintenance activities for each asset are described in the respective asset sections in Appendix D. 15.2.2 These are set out for each asset type under the risks and issues headings, in Appendix D. 15.2.3 Budgets for maintenance activities are included in Section D.1.
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 4 years (where known); and 15.3.4 an overview of other work being considered for the remainder of the AMP planning period.	The overarching approach to identifying and prioritising renewals investment is discussed in Section D.1. Asset specific considerations are provided throughout Sections D.3 to D.7 Expenditure projections are in Section 4.2 of the AMP Summary. Appendix D sets out interventions aligned with the specified timeframes.
15.4	The asset categories discussed in clauses 15.2 and 15.3 should include at least the categories in clause 7.	The information to meet Clauses 15.2 and 15.3 include the categories specified in Clause 7.
Non-network development, (maintenance and renewal)		

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Attachment A: Asset Management Plans		AMP Reference
16	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including- 16.1 a description of non-network assets 16.2 development, maintenance and renewal policies that cover them 16.3 a description of material capital expenditure projects (where known) planned for the next 5 years; and 16.4 a description of material maintenance and renewal projects (where known) planned for the next 5 years.	Section C.3 provides an overview of our non-network assets including asset descriptions and our approach to managing them. It also sets out interventions aligned with the specified timeframes.
Risk Management		
17	AMPs must provide details of risk policies, assessment, and mitigation, including- 17.1 methods, details and conclusions of risk analysis. 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; and 17.3 a description of the policies to mitigate or manage the risks of events identified in clause 17.2 of this attachment.	The asset risk management policy, principles, and framework are outlined under section C.2. Detail on asset-specific risks is provided within each asset section in Appendix D. Plans to mitigate the identified risks are discussed in Section C.2.6.
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.	This is set out in Section C.2.6.
Evaluation of performance		
19	AMPs must provide details of performance measurement, evaluation, and improvement, including-	See Section C.4.
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; and	This is provided in Section 3 of the AMP Summary

Attachment A: Asset Management Plans		AMP Reference
	3 Commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.	
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 provided in Section 3.4 of the AMP Summary 4 with further details set out in Section C.4 of the Appendices.
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; and	Section C.3.1 outlines the AMMAT results and identifies future improvement initiatives. It incorporates the results of an ISO55001 assessment and references broader asset management objectives and processes.
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	Improvement initiatives based on gaps identified in the AMMAT results are outlined in Section C.3.1.
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; and	Section C.3.2 describes relevant challenge and review processes as part of our governance approach.
20.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	Section C.3 outlines relevant governance roles.

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Appendix G. 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 Firstgas knowledge:

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.

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.

The forecasts in Schedules 11a, 11b, 12a, 12b are based on objective and reasonable assumptions which both align with First Gas Limited's corporate vision and strategy and are documented in retained records.

Director	Director
Dated: 29 Sep, 2025 12:09:10 PM GMT+13	Dated: 29 Sep, 2025 12:21:36 PM GMT+13