Pricing Methodology for Non-Maui Gas Transmission Services

Effective from 1 October 2016

Pursuant to
The Gas Transmission
Information Disclosure Determination 2012
NZCC24, 1 October 2012.

Schedule 18 Certification for Disclosures at the Beginning of the Pricing Year

We, Philippa Jane Dunphy and Euan Richard Krogh, being directors of First Gas Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

(a) The following attached information of First Gas Limited prepared for the purposes of clause 2.4.1 of the Gas Transmission Information Disclosure Determination 2012 in all material respects complies with that determination;

(b) The prospective financial or non-financial information included in the attached information has been forecast on a basis consistent with regulatory requirements or recognised industry standards.

____

Director

____

Director

29 August 2016

Table of Contents

EXECUTIVE SUMMARY

In April 2016, First Gas purchased the gas transmission system previously owned by Vector Limited. This network includes all of the high pressure gas transmission pipelines in the North Island, except the Maui pipeline. In June 2016, First Gas also purchased the Maui gas transmission pipeline that runs from Oaonui to Huntly, which was previously owned by Maui Developments Limited.

This document describes the Gas Transmission Pricing Methodology (GTPM) that applies to the non-Maui gas transmission assets owned by First Gas.

First Gas intends to develop a new gas transmission code and pricing methodology

First Gas intends to develop a new gas transmission code that will apply to both the ex-Vector and ex-MDL transmission systems. This new code will be developed in consultation with the Gas Industry Company, Shippers, major gas users and other stakeholders. The new code will replace both the Vector Transmission Code (VTC) and the Maui Pipeline Operating Code (MPOC), and will require a new GTPM. First Gas currently expects the new transmission code and pricing methodology to be in place from 1 October 2018.

The existing pricing methodology applied to non-Maui gas transmission assets will continue for the next two pricing years

Based on the time required to develop a new code and pricing methodology, we expect the current GTPM for non-Maui gas transmission to remain in use for the 2016/17 pricing year and 2017/18 pricing year. Vector developed the current GTPM after an extensive consultation process in 2012/13, and we consider that the GTPM remains fit for purpose.

This document is an edited version of the GTPM paper produced by Vector. It is intended to meet First Gas' obligations under the Gas Information Disclosure Determination, Decision NZCC24, 1 October 2012. This document provides information to enable interested parties to understand how gas transmission prices are set, and includes a description of the current GTPM's development.

This pricing methodology complies with regulatory requirements

First Gas' revenue from gas transmission services continues to be subject to the Gas Default Price-quality Path (GDPP).

This pricing methodology also aligns well with the Pricing Principles listed in the Gas Information Disclosure Determination. The Pricing Principles require the costs of transmission allocated to each consumer group to be tested against both the cost of a "stand alone" network and the cost of alternative energy supplies. This ensures that cost allocations do not result in prices so high as to incentivise consumers to use an alternative energy source. This benefits all consumers of gas transmission services by providing a pricing structure that encourages both the continued use and increased uptake of natural gas, thereby resulting in fixed network costs being spread across as many consumers as possible.

The Pricing Principles also require prices not to be less than incremental cost, ie that they are "subsidy-free". In practice this is not the case at all Delivery Points, usually because some or all of the load which such a DP was originally built to serve no longer exists. First Gas aims to stimulate growth where possible and will keep such DPs under review. This may involve considering a long-term strategy that takes account of the options available to the relevant consumers.

Transmission prices for 2016/17 have not materially changed

The transmission prices that will apply in the year commencing 1 October 2016 are not materially different from the prices that applied in 2015/16. The standard Throughput Fee (TPF) will remain unchanged, while the throughput fee on the Frankley Road pipeline will be reduced. Capacity Reservation Fees (CRFs) on pipelines where demand for capacity is highest will increase by up to 0.8%, while CRFs on other pipelines will either remain the same or reduce by up to 0.8%.

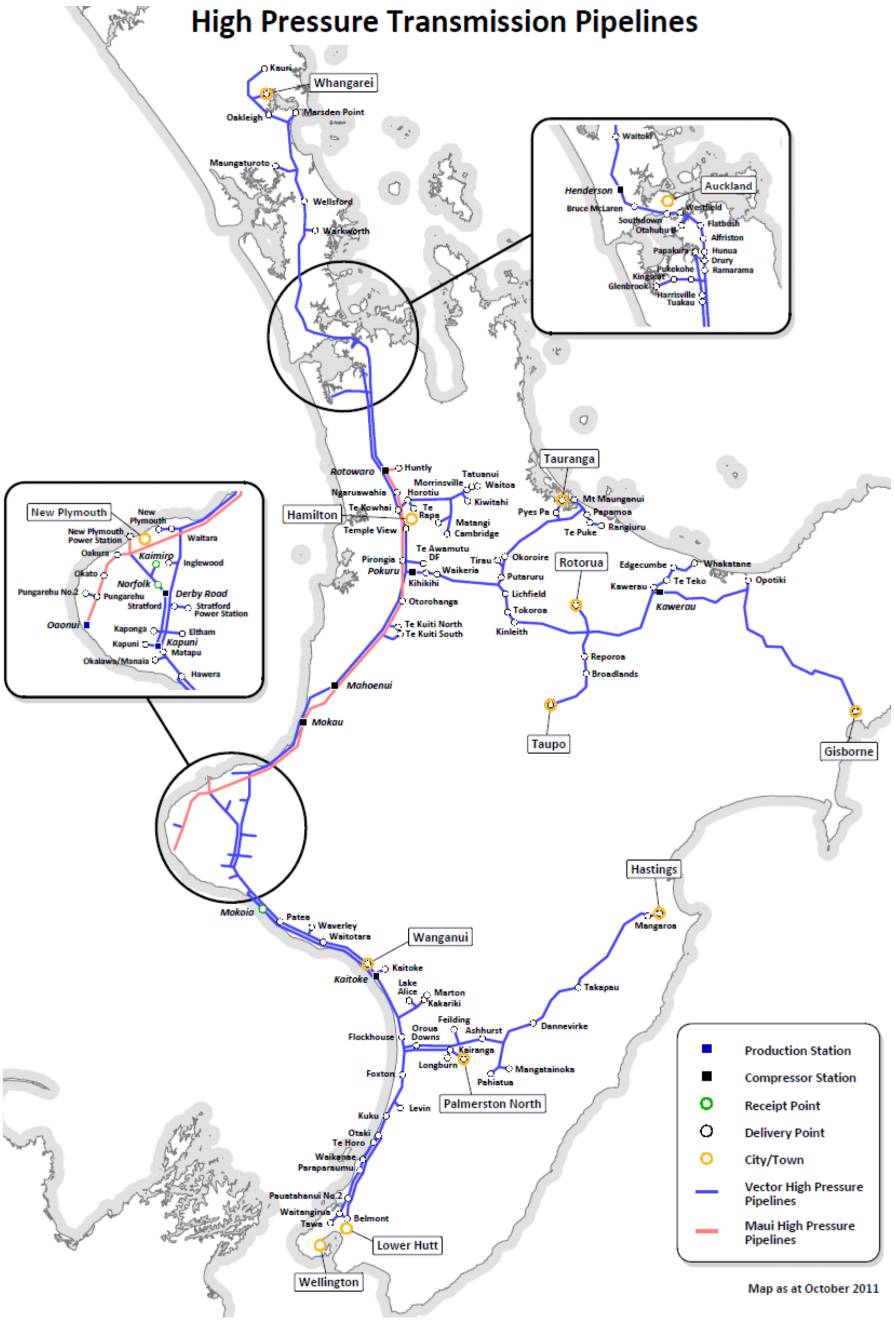
This will result in weighted average prices for 2016/17 being approximately 0.2% higher than 2015/16.

Section 1 Overview

1.1. Background

First Gas provides gas transmission services in the North Island over a network comprising approximately 2,200 km of pipeline. The system was largely built between 1968 and the mid-1980s by the Natural Gas Corporation (NGC). It was purchased by Vector in 2005, and subsequently by First Gas in April 2016. The map below shows both the transmission system purchased from Vector (in blue) and the ex-MDL pipeline (in brown).

Figure 1 First Gas' gas transmission system:



Gas is taken from the transmission system at some 130 Delivery Points (DPs), owned by First Gas. These DPs supply both distribution networks and large gas consumers such as industrial plants and power stations. First Gas contracts with Shippers. First Gas transports gas from sources of supply (currently all in Taranaki) through the transmission system for Shippers. At present there are seven Shippers. All current Shippers operate as gas retailers, though some also ship gas to their own gas consuming facilities.

Since 1 July 2013, the gas transmission system has been subject to regulation under the GDPP. This required an initial starting price adjustment (applied in 2013) and stipulated a CPI-X plus pass-through price path.

In addition, the Determination requires the GTB to demonstrate how (and if not why) its prices comply with the Pricing Principles.

In 2013, Vector (as the previous owner) undertook an extensive review of the gas transmission pricing methodology. The current GTPM is the outcome of that process.

1.2. Applicable regulations

This disclosure is prepared in accordance with clause 2.4 of the Determination. Compliance with the requirements of this clause is demonstrated in the compliance matrix in Section 6.

The GDB's gas transmission services revenue is set in accordance with the GDPP.

The Pricing Principles are specified in clause 2.5.2 of the Input Methodologies.

1.3. Additional disclosures

Gas transmission prices are subject to annual approval by the GTB's Board of Directors, and are set to comply with the GDPP. They should also deliver the Target Revenue.

First Gas' Board of Directors has not made any decision to amend the transmission pricing structure beyond the 2016/17 pricing year or approved any Pricing Strategy.

1.4. Price setting policy framework

1.4.1. Ec onomic, commercial and practical drivers

This section highlights some of the key factors that influenced the design of the current GTPM. Current transmission prices are founded on an application of economic pricing principles, subject to practical, physical and commercial constraints. An understanding of these factors assists in understanding the various decisions underpinning the current GTPM.

Most costs to be recovered are shared costs, which may be difficult to attribute to particular consumers except at high levels of aggregation

The transmission system can be broadly described as a network of pipelines radiating from Taranaki and supplying multiple Connection Points along each pipeline's length. A key feature of the gas transmission system is that many of the assets used to convey gas are used by multiple Shippers and many consumers.

The shared use of a significant portion of assets has significant implications for the development of transmission prices. Transmission prices substantially represent a recovery of common costs, rather than being directly attributable to the provision of a specific service to a connection. Decisions must inevitably be made in determining appropriate allocation methods. This has constrained the scope of the Cost of Supply Model (COSM) to high levels of aggregation, with more general "cost reflectivity" principles applying to the manner in which prices are developed consistent with the aggregated cost allocations.

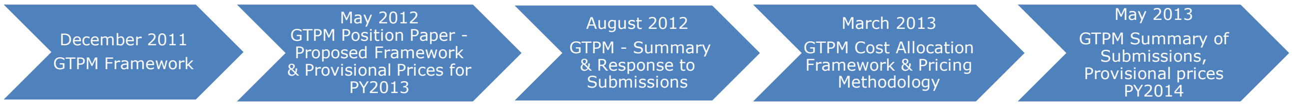
There are practical limits on the ability of prices to improve efficiency

The GTB normally contracts with consumers indirectly, through Shippers, and in effect provides a wholesale transmission services to Shippers. Shippers are able to repackage the transmission charges they pay, meaning that price signals do not necessarily reach the consumer in an "unmodified" way. In any event, gas transmission costs make up only a small portion of the average consumer's bill, so any price signal at the transmission level tends to be overwhelmed by wholesale gas costs, distribution charges and retail costs.

1.5. Development of the Current GTPM

The current GTPM was developed as part of an extended consultation process with Shippers and consumers, summarised in Figure 2.

Figure 2 GTPM consultation process



The December 2011 Framework paper communicated the context and objectives of the review together with an outline of the indicative process.

The 31 May 2012 GTPM Position Paper developed an Assessment Framework to guide the development of the GTPM. The Assessment Framework included the Pricing Principles, and continues to be relevant under the GDPP. Vector applied this framework to determine provisional price changes for 2013 which involved an adjustment to the balance between fixed and variable Price Components.

On 31 August 2012, Vector published a Summary and Response to Submissions by interested parties on the Position Paper. This included confirmation of final prices, which reflected submitters' concerns regarding the re-distributive impact of the provisional price proposal on Auckland and Wellington DPs.

The reduced Throughput Fee and uniform dollar increase in CRFs proposed meant a larger relative increase to CRFs in Auckland. The price changes were driven primarily by a desire to rebalance the fixed and variable charge components to better reflect underlying costs, but also took into account the need to minimise distortions to incentives (and in particular incentivise less consumption in Auckland, where capacity was constrained at the time). The interim price change took the fixed:variable revenue split from approximately 60%:40% to 65%:35%.

On 28 March 2013, Vector published a consultation paper on the cost allocation framework and methodology to apply within the GTPM. This paper introduced the approach described in sections 3.2 and 3.3. Cost allocations and prices were prepared on a Connection Point basis.

On 31 May 2013, Vector summarised feedback received on the 28 March paper and notified provisional prices using the revised Pricing Regions described in section 3.1.

In May 2014, Vector notified provisional prices for the 2014/15 year. The provisional prices incorporated uniform increases to all prices. Shippers provided no feedback on the provisional prices. On 29 August 2014, Vector notified final prices for the 2014/15 year to Shippers. These prices became effective from 1 October 2014.

In May 2015, Vector notified provisional prices for the 2015/16 year. The provisional prices incorporated uniform increases to CRFs, with an additional increase to the throughput fee on the Frankley Road pipeline. Shippers provided no feedback on the provisional prices. On 28 August 2015, Vector notified final prices for the 2015/16 year. These prices became effective from 1 October 2015.

1.6. Development of a new transmission code and pricing methodology

Having just become the new owner of all open-access gas transmission pipelines in the North Island, a high priority for First Gas is to lead the development of a single new gas transmission code covering that entire gas transmission network. Considering the work that this will involve, the new gas transmission code is not likely to be in place before the 2018/19 pricing year.

We see any gas transmission pricing methodology as being inseparable from the prevailing gas transmission code. First Gas inherited the current GTPM when it purchased the GTB from Vector, and it is clearly fit for purpose under the VTC. However, the GTPM does not cover pricing for the former Maui Pipeline and is unlikely to be an appropriate fit for a new code that covers the entire gas transmission network. The design of a new GTPM must therefore occur in step with the development of a new gas transmission code.

The current GTPM will continue to apply for the remainder of the current regulatory period. First Gas also considers that it should continue until such time as the service and pricing-related elements of the new gas transmission code are agreed with Shippers and other stakeholders. In May 2016, First Gas notified provisional prices for the 2016/17 year. Shippers provided no feedback on the provisional prices. On 29 August 2016, First Gas notified Shippers of final prices for the 2016/17 year. Some CRFs will increase by up to 0.8%, while others will decrease by a similar amount or remain unchanged. The TPF will remain unchanged, while the throughput fee for the Frankley Road pipeline will decrease.

Section 2 Commercial price-setting framework

2.1. Competitive pressures on pricing

The starting point for establishing prices for gas transmission services is a consideration of the role of gas as a fuel. Unlike electricity, gas is a discretionary fuel for most consumers. Given the substantial costs of the transmission system, there is a strong commercial drive on the GTB to maintain and improve economies of density (more consumers per unit of pipeline) and economies of scale (more GJ delivered per unit of pipeline). Improved economies of scale and density mean that the GTB can use its capital more efficiently; consumers ultimately benefit from the sharing of common costs across a wider number of consumers and/or GJ. A more diverse consumer base is also in the GTB's commercial interests as it mitigates asset stranding risks.

2.2. Pricing against alternative energy sources

A key part of The GTB's pricing methodology is testing proposed prices against the lowest cost alternative energy source.

In 2012 Vector asked PricewaterhouseCoopers (PwC) to calculate an implied cap for gas transmission cost based on the cost of alternative fuels, using the approach summarised in Figure 3. The implied cap on gas transmission cost is a proxy for the maximum price that could be charged for a gas transmission service before an alternative fuel becomes more cost effective.

Figure 3 Calculation of implied transmission cost

All-in delivered cost of alternative

Less

– GST
– replacement capital expenditure (annualised)
– gas cost
– retailer margin
– gas distribution cost (if relevant)
– other costs

= Implied cap on gas transmission cost

Bottled LPG, biomass, and coal were the alternative fuels examined. For each consumer group the lowest implied transmission cost was selected from these three fuels. As shown in Figure 4, bottled LPG sets the implied transmission cap for domestic and commercial consumers, while coal sets the implied transmission cap for industrial consumers.

Figure 4 Implied transmission costs caps set by alternative fuel costs

Consumer type	Alternative fuel	Implied transmission cap ($/GJ 2012)
Small domestic	Bottled LPG	39.05
Medium domestic	Bottled LPG	31.57
Large domestic	Bottled LPG	27.75
Small commercial	Bottled LPG	20.22
Medium commercial	Bottled LPG	15.24
Large commercial	Bottled LPG	20.09
Large industrial	Coal	4.20
Very large industrial	Coal	4.90

Vector used the above to derive weighted average transmission cost caps for Connection Points. The distribution of consumer types at each DP was informed by institutional knowledge, the ratio of TOU and non-TOU consumers obtained from the transmission allocation agent, as well as samples of the actual breakdown of consumer categories obtained from Vector’s gas distribution business.

The implied transmission cost caps are incorporated into the GTB’s price-setting process, with SAC being set to the lesser of the implied transmission cap set by alternative fuels and the cost of an alternative network.

There are limits to the extent to which a standardised pricing schedule can take account of the particular circumstances of individual consumers, so in certain circumstances the GTB and a consumer may enter into a non-standard contract as described in Section 5.

Section 3 Methodology for standard prices

This section describes the methodology the GTB uses to calculate prices for gas transmission services.

The GTB delivers gas from the gas transmission system Delivery Points (DPs). However, for pricing purposes the GTB allocates costs by Connection Points and then by Pricing Regions. Section 3.1 provides the rationale for the use of Connection Points and Pricing Regions, and lists the Pricing Regions and Connection Points comprising multiple DPs.

Section 3.3 describes the operation of the GTB’s Cost of Service Model (COSM), used to allocate costs to Connection Points and Pricing Regions. Because the GTB operates under a revenue cap, the costs that are inputs to COSM will not necessarily add to the amount of the revenue cap. The allocated costs are therefore used to establish the proportion of the Target Revenue that is recovered from each consumer group. The allocation of Target Revenue is described in Section 3.4 and any resulting price changes in Section 3.5.

3.1. Pricing Regions

DPs in the same or close geographical location are linked to a single “Connection Point” on the transmission system, e.g. the Edgecumbe Connection Point combines the Edgecumbe dairy factory and Edgecumbe town DPs into one Connection Point with a single price. This approach means that DPs which are adjacent (or nearly adjacent) do not have different prices simply as a result of an artefact of how the cost allocation methodology and pricing methodology work.

Figure 5 below lists all Connection Points which have multiple DPs linked to them. The remaining CPs have only a single DP linked to them.

Figure 5 Aggregation of Delivery Points into Connection Points

Connection Point	Delivery Points
Ammonia Urea	Ballance 8201 and 9626
Drury	Drury 1
Edgecumbe	Edgecumbe, Edgecumbe DF
Greater Auckland	Westfield, Henderson, Papakura, Waikumete, Bruce McLaren
Greater Hamilton	Temple View, Te Kowhai
Greater Mt Maunganui	Mt Maunganui, Papamoa
Greater Tauranga	Tauranga, Pyes Pa
Greater Waitangirua	Waitangirua, Pauatahanui 2
Hastings	Hastings, Hastings (Nova)
Hawera	Hawera, Hawera (Nova),
Hunua	Hunua, Hunua (Nova), Hunua 3
Kawerau	Kawerau, Kawerau (ex-Caxton), Kawerau (ex-Tasman)
Kinleith	Kinleith, Kinleith (Paper mill)
Kiwitahi	Kiwitahi 1 (Peroxide), Kiwitahi 2
Marsden	Marsden 1 (NZRC), Marsden 2
Morrinsville	Morrinsville, Morrinsville DF
Okaiawa \ Manaia	Manaia, Okaiawa
Tawa	Tawa A, Tawa B (Nova)
TCC \ Stratford	Stratford 2 (Peaker), Stratford 3 (Storage), TCC Power Station
Te Awamutu \ Kihikihi	Kihikihi, Te Awamutu DF

Tirau	Tirau, Tirau DF

All stakeholders who submitted on Vector's March 2013 proposals supported greater levels of aggregation. Consequently, Vector adopted a broader aggregation into the Pricing Regions shown in Figure 6. (First Gas has maintained this approach for the 2016/17 pricing year, and does not anticipate making any changes until the new transmission code and GTPM come into effect.) This means that DPs in a similar geographic area do not have different prices simply as a result of an artefact of how the cost allocation methodology and pricing methodology work.

Figure 6 Aggregation of Delivery Points into Pricing Regions

Region	Delivery points
Northland	Marsden 1 (NZRC), Marsden 2, Kauri DF, Maungaturoto DF, Warkworth, Wellsford, Whangarei
Auckland	Alfriston, Drury 1, Flat Bush, Glenbrook (Steel Mill), Greater Auckland, Harrisville, Hunua, Hunua (Nova), Hunua 3, Kingseat, Pukekohe, Ramarama, Tuakau 2, Waitoki
Waikato north	Cambridge, Horotiu, Huntly Town, Kiwitahi 1 (Peroxide), Kiwitahi 2, Matangi, Morrinsville, Morrinsville DF, Ngaruawahia, Tatuanui DF, Te Rapa Cogen Plant, Waitoa
Hamilton	Greater Hamilton, Temple View, Te Kowhai
Waikato south	Kihikihi, Kinleith, Kinleith (Paper mill), Lichfield DF, Lichfield 2, Okoroire Springs, Otorohanga, Pirongia, Putaruru, Te Awamutu DF, Te Kuiti North, Te Kuiti South, Tirau, Tirau DF, Tokoroa, Waikeria
Western Bay of Plenty	Greater Mt Maunganui, Greater Tauranga, Rangiuru Te Puke
Eastern Bay of Plenty	Broadlands, Edgecumbe, Edgecumbe DF, Gisborne, Kawerau, Kawerau (ex-Caxton), Kawerau (ex-Tasman), Opotiki, Reporoa, Rotorua, Taupo, Te Teko, Whakatane
Taranaki	Eltham, Inglewood, Kaponga, New Plymouth, Oakura, Okato, Opunake, Pokuru 2 Delivery, Pungarehu No 1, Pungarehu No 2, Stratford, Stratford 2 (Peaker), Stratford 3 (Storage), TCC Power Station, Waitara
Manawatu-Wanganui	Hawera, Hawera (Nova), Kaitoke, Kakariki, Lake Alice, Okaiawa \ Manaia, Marton, Matapu, Mokoia, Patea, Waitotara, Wanganui, Waverley
Hawke's Bay	Ashhurst, Dannevirke, Feilding, Flockhouse, Hastings, Hastings (Nova), Kairanga, Longburn, Mangaroa, Mangatainoka, Oroua Downs, Pahiatua, Pahiatua DF, Palmerston North, Takapau
Wellington	Belmont, Foxton, Greater Waitangirua, Kuku, Levin, Otaki, Paraparaumu, Pauatahanui 2, Tawa A, Tawa B (Nova), Te Horo, Waikanae 2

3.2. Cost categories

Within the GTPM, costs are categorised into Connection Costs and Shared Costs. Connection Costs are the costs directly attributable to a Delivery Point or a Pricing Region; Shared Costs account for the balance of the GTB's Total Allocable Cost.

3.2.1. Total allocable cost

The Total Allocable Costs is a proxy for Target Revenue, which is based on a building block calculation of cost (the four regulatory "building blocks" are highlighted in bold). The calculation of Total Allocable Cost is shown in Figure 7.

Figure 7 Calculation of total allocable cost

System fixed assets	485,828,324
Non-system fixed assets	6,362,391
Total assets	492,190,715
Return on capital (excl. revaluation of system fixed assets)	**34,764,852**
Depreciation	**18,953,037**
Fuel cost	3,058,113
Maintenance cost	11,373,279
Pass-through cost	4,892,878
Other costs	-
Indirect costs	12,373,606
Total expenses	**31,697,876**
Regulatory tax allowance	**11,850,123**
Total allocable cost	97,265,888

3.2.2. Connection costs

Connection Costs are the costs directly attributable to each Connection Point. This is determined by means of a "but for" test which identifies all assets dedicated to a Connection Point and all expenses directly associated with a Connection Point. The question underlying the "but for" test is:

"but for the existence of this Connection Point, would these assets exist or these costs be incurred?"

If the assets would not exist or the expenses would not be incurred but for the existence of the Connection Point then they are connection assets and the connection expenses are allocated to the Connection Point.

Once the connection assets and connection expenses have been identified, connection costs are calculated as:

Connection costs = Discount rate x Asset value – Asset revaluation + Depreciation + Connection expenses + Tax

Grouping DPs into Connection Points or Pricing Regions ensures that incremental costs are not artificially lowered because connection assets are shared between multiple DPs. Figure 8 overleaf shows the calculation of Connection Costs by Pricing Region.

Figure 8 Calculation of connection costs by Pricing Region

Pricing region	Dedicated connection assets	Return on capital (excl. revaluations)	plus depreciation	plus maintenance costs	plus regulatory tax allowance	Connection costs
Northland	12,519,481	738,618	259,837	194,293	305,370	1,498,118
Auckland	11,773,886	694,630	369,672	525,042	287,184	1,876,528
Waikato North	5,635,975	332,509	164,300	194,441	137,470	828,719
Hamilton	1,573,871	92,854	42,042	63,268	38,389	236,554
Waikato South	9,517,797	561,526	258,391	298,828	232,154	1,350,899
Western Bay of Plenty	4,301,868	253,799	108,065	106,627	104,929	573,421
Eastern Bay of Plenty	34,776,762	2,051,741	618,321	374,171	848,260	3,892,493
Taranaki	12,729,522	751,010	363,850	329,468	310,493	1,754,821
Manawatu-Wanganui	3,584,705	211,488	149,170	183,518	87,437	631,613
Hawke’s Bay	7,055,999	416,286	190,624	243,908	172,107	1,022,926
Wellington	5,108,890	301,412	191,935	250,223	124,614	868,184
Total	108,578,755	6,405,873	2,716,208	2,763,788	2,648,408	14,534,277

3.2.3.Shared costs

Shared Costs are those costs not directly attributable to a Connection Point. The allocation of Shared Costs recovers the balance of the Total Allocable Cost. Shared Costs are calculated as:

Figure 9 Calculation of shared costs

Component	Value
Total allocable cost	97,265,888
less	
Connection costs	14,534,277
Shared costs	82,731,611

Shared Costs are recovered via the Cost Allocation Methodology described in Section 3.3.

3.3. Cost allocation model for shared costs

The GTB uses a Cost Allocation Model to allocate shared costs to each Connection Point. This enables the GTB to set prices in a cost reflective manner.

3.3.1. Expense categories

Regulatory requirement

*2.4.3(4) Where applicable, identify the key components of **target revenue** required to cover the costs and return on investment associated with the **GTB**'s provision of **gas transmission services**. Disclosure must include the numerical value of each of the components;*

The categories of expense allocated by the Cost Allocation Model are:

- Return on capital;
- Depreciation on system fixed assets;
- Fuel cost;
- Maintenance costs;
- Pass-through costs;
- Indirect costs; and
- Regulatory tax allowance.

Costs with a meaningful cost driver

The GTB considers that the return on capital, depreciation, maintenance costs, and tax expenses can all be allocated on the basis of asset values (both connection assets and allocated shared assets):

- The return on capital and depreciation arise directly as a result of assets and asset values;

- Maintenance is related to assets, and it is common practice in cost allocation to treat asset values as a proxy for assets; and

- Tax expense is primarily incurred because of the Return on Assets and the difference between regulatory depreciation and regulatory tax depreciation.

The allocation of the above costs first requires that assets be allocated to CPs. Connection assets are allocated directly, and shared assets are allocated as described below.

Fuel costs can also be allocated directly, as virtually all DPs have a heater (sized for the throughput) and are downstream of a compressor station. Fuel costs are therefore allocated according to throughput for such DPs.

Costs requiring a proxy cost allocator

The GTB considers that the following cost categories require proxy cost allocators:

- Shared network assets (i.e. System Fixed Assets);
- Non-system fixed assets;
- Contributions and all other revenues (if any);
- Indirect costs; and
- Pass-through and other direct costs;
- Any under- or over-recoveries that arise from imposing the IC and SAC bounds.

The GTB's view is that Maximum Flow is the preferred allocator for shared costs because transmission assets are sized to meet peak capacity requirements. As a measure of the capacity actually used, Maximum Flow presents the strongest link to costs and moves allocation closest to what might be implied in a market. Compared with (say) a distance-based approach, cost allocations will increase on highly utilised or constrained parts of the network and fall on underutilised or unconstrained parts of the system. While this does not provide a market-based capacity price, it does improve pricing signals on constrained and unconstrained parts of the gas transmission system.

Each component of cost, its value, and the allocator for shared costs are summarised in Figure 10.

Figure 10 Summary of cost category and allocator for shared costs

Cost category	Total	Connection	Shared	Allocator for shared costs
System fixed assets	485,828,324	108,578,755	377,249,569	Maximum flow
Non-system fixed assets	6,362,391		6,362,391	Maximum flow
Total assets	492,190,715	108,578,755	383,611,960	
Return on capital (excl. revaluation of system fixed assets)	34,764,852	6,405,873	28,358,979	Calculated
Depreciation	18,953,037	2,716,208	16,236,829	Maximum flow
Fuel cost	3,058,113		3,058,113	Fuel use
Maintenance cost	11,373,279	2,763,788	8,609,491	System fixed assets
Pass-through cost	4,892,878		4,892,878	Maximum flow
Other costs	-		-	Maximum flow
Indirect costs	12,373,606		12,373,606	Maximum flow
Total expenses	31,697,876	2,763,788	28,934,088	
Regulatory tax allowance	11,850,123	2,648,408	9,201,715	System fixed assets
Total allocable cost	97,265,888	14,534,277	82,731,611	

3.3.2. Cost allocation

Following from the discussion above and Figure 7, the allocators used to allocate shared costs are:

- Maximum Flow – the actual maximum flow rate recorded for the Connection Point;
- System fixed assets – the total value of attributed (Connection) and allocated (Shared) assets for the Connection Point;
- Fuel use – the quantity of compressor and heater fuel attributed to a Connection Point.

The value of each allocator by Pricing Region is shown in Figure 11. The table also includes the proportional allocation to each Pricing Region for a given allocator.

Figure 12 shows the resulting allocation of shared costs by Pricing Region.

Figure 11 Cost allocators by Pricing Region

Pricing region	Absolute value						Percentage value			
	Maximum flow	**Compressor fuel**	**Heater fuel**	**Dedicated assets**	**Allocated shared assets**	**Total system fixed assets**	**Maximum flow**	**Fuel use (*)**	**Shared system fixed assets**	**System fixed assets**
Northland	19,212	3,358,298	3,357,229	12,519,481	11,557,458	24,076,938	3.06%	4.79%	3.06%	4.96%
Auckland	193,519	41,492,589	15,014,802	11,773,886	116,416,301	128,190,187	30.86%	50.81%	30.86%	26.39%
Waikato North	37,293	5,997,692	6,048,541	5,635,975	22,434,534	28,070,509	5.95%	8.57%	5.95%	5.78%
Hamilton	14,233	1,373,906	1,373,906	1,573,871	8,562,216	10,136,087	2.27%	1.96%	2.27%	2.09%
Waikato South	37,255	4,067,864	4,338,133	9,517,797	22,411,674	31,929,471	5.94%	5.89%	5.94%	6.57%
Western Bay of Plenty	7,390	945,643	945,643	4,301,868	4,445,639	8,747,507	1.18%	1.35%	1.18%	1.80%
Eastern Bay of Plenty	25,430	3,936,986	3,936,986	34,776,762	15,298,051	50,074,812	4.06%	5.62%	4.06%	10.31%
Taranaki	199,875	1,000,880	20,609,935	12,729,522	120,239,791	132,969,313	31.87%	7.63%	31.87%	27.37%
Manawatu-Wanganui	15,571	2,049,054	2,045,484	3,584,705	9,367,123	12,951,828	2.48%	2.92%	2.48%	2.67%
Hawke's Bay	27,791	3,582,044	3,566,056	7,055,999	16,718,369	23,774,368	4.43%	5.10%	4.43%	4.89%
Wellington	49,534	4,255,301	2,026,134	5,108,890	29,798,413	34,907,303	7.90%	5.36%	7.90%	7.19%
Total	627,103	72,060,258	63,262,850	108,578,755	377,249,569	485,828,324	100.00%	100.00%	100.00%	100.00%

* The Fuel use allocator is calculated as (80% x the proportion of compressor fuel) + (20% x the proportion of heater fuel).

Figure 12 Calculation of shared costs by Pricing Region

Pricing region	System fixed assets	Non-system fixed assets	Subtotal assets	Return on capital	Depreciation	Fuel cost	Maintenance cost	Pass-through cost	Indirect costs	Regulatory tax allowance	Total
Allocator	**Maximum flow**	**Maximum flow**	**Calculated**	**Calculated**	**Maximum flow**	**Fuel use**	**Shared SFA**	**Maximum flow**	**Maximum flow**	**Shared SFA**	
Northland	11,557,458	194,919	11,752,377	868,809	497,433	146,474	263,761	149,899	379,079	281,905	2,587,360
Auckland	116,416,301	1,963,385	118,379,685	8,751,362	5,010,560	1,553,862	2,656,822	1,509,904	3,818,399	2,839,578	26,140,487
Waikato North	22,434,534	378,363	22,812,897	1,686,471	965,583	262,102	511,995	290,973	735,842	547,214	5,000,180
Hamilton	8,562,216	144,404	8,706,620	643,647	368,518	59,928	195,405	111,051	280,837	208,846	1,868,231
Waikato South	22,411,674	377,977	22,789,652	1,684,752	964,599	180,047	511,473	290,677	735,092	546,656	4,913,297
Western Bay of Plenty	4,445,639	74,977	4,520,615	334,192	191,340	41,248	101,457	57,659	145,815	108,436	980,148
Eastern Bay of Plenty	15,298,051	258,005	15,556,055	1,150,000	658,428	171,726	349,128	198,414	501,769	373,144	3,402,609
Taranaki	120,239,791	2,027,869	122,267,659	9,038,785	5,175,123	233,236	2,744,081	1,559,494	3,943,808	2,932,839	25,627,367
Manawatu-Wanganui	9,367,123	157,978	9,525,102	704,155	403,161	89,342	213,774	121,490	307,237	228,479	2,067,639
Hawke's Bay	16,718,369	281,959	17,000,328	1,256,770	719,559	156,089	381,542	216,835	548,355	407,788	3,686,937
Wellington	29,798,413	502,556	30,300,969	2,240,036	1,282,524	164,059	680,052	386,482	977,374	726,831	6,457,356
Total	377,249,569	6,362,391	383,611,960	28,358,979	16,236,829	3,058,113	8,609,491	4,892,878	12,373,606	9,201,715	82,731,611

3.3.3. Adjustments

Comparison against incremental cost

Any CP with a total allocated cost less than Short Run Incremental Cost has the value of allocated cost reset to Short Run Incremental Cost.

Comparison against least cost alternative

As described in section 2.2, the total cost allocated to each CP is compared to the weighted average SAC for that CP to ensure that cost allocations do not result in prices that would provide an incentive for consumers to disconnect. Any CPs with a total allocated cost greater than SAC are reset to the SAC (i.e. the lesser of the total allocated cost and SAC).

Reallocation of shortfall

The comparison against SAC results in a total reduction in cost allocated to some CPs of approximately $11m. This amount is reallocated amongst CPs using Maximum Flow as the proxy allocator, subject to the constraint that total costs allocated to each CP must not exceed the relevant SAC.

3.3.4. Total allocated costs by Pricing Region

Figure 13 shows the total allocated costs by Pricing Region. The allocated cost before adjustments is the sum of connection costs (Figure 8) and allocated shared costs (Figure 12). Allocated costs are then reduced by an aggregate $16.2 million as a result of imposing the SAC constraint. These costs are then reallocated as described above.

Figure 13 Total allocated costs by Pricing Region

Pricing region	Connection costs	Shared costs	Allocated costs before adjustments	Impose SAC constraint	Recoveries	Allocated cost after adjustments
Northland	1,498,118	2,587,360	4,085,478	(23,182)	728,952	4,791,247
Auckland	1,876,528	26,140,487	28,017,015	(26,687)	7,344,134	35,334,462
Waikato North	828,719	5,000,180	5,828,900	(2,439,802)	412,442	3,801,539
Hamilton	236,554	1,868,231	2,104,786	(1,282,834)	0	821,952
Waikato South	1,350,899	4,913,297	6,264,196	(15,907)	1,418,621	7,666,910
Western Bay of Plenty	573,421	980,148	1,553,569		253,962	1,807,531
Eastern Bay of Plenty	3,892,493	3,402,609	7,295,102		1,835,978	9,131,080
Taranaki	1,754,821	25,627,367	27,382,188	(12,232,596)	719,357	15,868,948
Manawatu-Wanganui	631,613	2,067,639	2,699,252	(108,083)	606,599	3,197,768
Hawke’s Bay	1,022,926	3,686,937	4,709,863	(69,961)	1,039,194	5,679,095
Wellington	868,184	6,457,356	7,325,540	(39,701)	1,879,516	9,165,355
Total	14,534,277	82,731,611	97,265,888	(16,238,753)	16,238,753	97,265,888

3.4. Price setting and the allocation of target revenue

3.4.1. Target revenue

Regulatory requirement

*2.4.3(3) State the **target revenue** expected to be collected for the **pricing year** to which the pricing methodology applies;*

The GTB sets its prices to recover an amount no greater than the Allowable Notional Revenue (ANR) under the GDPP. Compliance with the Allowable Notional Revenue requirement is determined using current year prices multiplied by quantities lagged by two years. Once prices are set to comply with the GDPP, the GTB then determines how much revenue these prices will deliver based on forecast quantities in the forthcoming pricing year: this is the Target Revenue. Due to the difference in quantities used in the GDPP and in calculating the Target Revenue, Target Revenue normally differs from the ANR. Target revenue for the 2016/17 pricing year is set out in Figure 14.

Figure 14 Determining Target Revenue

Allowable Notional Revenue	91,068,142
Pass-through and recoverable costs	4,892,878
Subtotal	95,961,020
Pricing and quantity adjustments	1,304,868
Target revenue from prices	97,265,888

The post-allocation adjustments occur as part of the price setting process described in section 3.4.2 below.

3.4.2. Setting prices

Prices do not flow mechanistically from cost allocations. The GTB can still vary the fixed:variable split, and move CRFs by uniform or different amounts. For the 2016/17 pricing year First Gas has:

- Kept the 2015/16 Throughput Fee (TPF) of $0.06/GJ unchanged across all Pricing Regions; and
- Increased CRFs in some Pricing Regions by $0 to $3 per GJ of reserved capacity
- Decreased CRFs in some Pricing Regions by $2 to $4 per GJ of reserved capacity.

On average, CRFs have increased by 0.1% for the 2016/17 pricing year. On the Frankley Road Pipeline the standard transmission price is now 100% variable, and the throughput fee has decreased to $0.33/GJ.

The CRF is expressed in whole dollars and is generally set at a level that will comply with the GDPP and (consequently) recover approximately the same Target Revenue as implied by the cost allocations plus a pro-rata allocation of pass-through costs.

Setting whole-dollar CRFs means that prices may not precisely recover the ANR plus pass-through costs.

3.4.3. Target revenue by Pricing Region

Regulatory requirement

*2.4.3(6) Where applicable, describe the method used by the **GTB** to allocate the **target revenue** among **consumers**, including the numerical values of the **target revenue** allocated to **consumers** and the rationale for allocating it in this way;*

The Target Revenue for gas transmission services is not directly allocated to consumers. Instead, it is allocated using the cost allocations described in Sections 3.2 and 3.3 above, and subject to the pricing adjustments described in section 3.4.2. It is neither appropriate nor possible to publicly disclose the Target Revenue for individual consumers. The cost allocation approach described above allocates costs to Connection Points and Pricing Regions; multiple Shippers may take delivery at any given Connection Point or Pricing Region, and it is the allocation for the Pricing Region that is relevant. The outcome of the pricing methodology is the allocation between Pricing Regions shown in Figure 15.

Figure 15 Target revenue by Pricing Region

Pricing region	Target revenue from prices (P_{i2017},Q_{i2017})
Northland	$4,515,711
Auckland	$25,544,128
Waikato North	$4,877,776
Hamilton	$1,224,365
Waikato South	$9,274,689
Western Bay of Plenty	$2,299,444
Eastern Bay of Plenty	$8,654,312
Taranaki	$18,419,730
Manawatu-Wanganui	$3,923,480
Hawke’s Bay	$7,420,732
Wellington	$11,111,522
Target Revenue	$97,265,888

3.4.4. Revenue by price component

Regulatory requirement

*2.4.3(7) State the proportion of **target revenue** (if applicable) that is collected through each **price component** as **publicly disclose**d under clause 2.4.18.*

The Determination defines “Price Component” as the various tariffs, fees and charges that together make up the total price paid, or payable, by a consumer. The standard gas transmission Price Components, as specified in the VTC, are:

- Capacity Reservation Fee (CRF), applied to the (annual) GJ of capacity reserved at a DP;
- Throughput Fee (TPF), applied to GJ delivered; and
- Overrun Fee, equal to 10 times the relevant CRF divided by 365 (or 366) days and applied to GJ delivered in excess of reserved capacity.

Different Price Components may apply under the various types of non-standard contract used on the transmission system, including fixed fees (per GJ of capacity or per day), variable fees and fees for interruptible capacity.

The proportion of revenue recovered by each price component is shown in Figure 16. The variable component of First Gas' Target Revenue is comprised of Throughput Fees and Overrun Fees, and currently accounts for 13% of revenue.

Figure 16 Proportion of target revenue by price component

Price component	Target revenue	Proportion
Capacity Reservation Fees	$68,586,407	70.5%
Other Fixed Fees	$10,720,638	11.0%
Throughput Fees	$6,424,180	6.6%
Over-run Fees	$6,263,879	6.4%
Interruptible Contracts	$5,270,783	5.4%
	$97,265,888	100%

3.5. Price changes

Regulatory requirement

*2.4.3(5) If **prices** have changed from **prices** disclosed for the immediately preceding **pricing year**, explain the reasons for changes, and quantify the difference in respect of each of those reasons;*

From 1 October 2016, the weighted average increase in gas transmission prices will be 0.2%.

This increase represents the combined effect of increases to pass through and recoverable costs, the CPI adjustment to ANR and changes to quantities in the relevant year under the GDPP.

The CPI increase to the ANR for the 2016/17 pricing year is 0.3%.

Figure 17 below shows the price changes by Pricing Region. To calculate the weighted average price change, the notional revenue for 2015/16 has been recalculated using updated quantities (Q_{i2015}), ie the same as in the calculation of notional revenue for 2016/17. The final column of Figure 17 shows the total percentage change in prices for each Pricing Region.

The GTPP allows recovery of defined pass-through and recoverable costs. For the 2016/17 pricing year, pass-through costs are $4,892,878, an increase of $0.98 million from the previous year. The increase to pass-through and recoverable costs represents an increase of 1% to the total weighted average prices.

Figure 17 Price changes by Pricing Region

Pricing Region	Notional revenue		Revenue change
	P_{i2017},Q_{i2015}	P_{i2016},Q_{i2015}	
Northland	$4,454,921	$4,447,491	0.2%
Auckland	$25,200,255	$25,004,222	0.8%
Waikato North	$4,812,112	$4,778,123	0.7%
Hamilton	$1,207,882	$1,200,222	0.6%
Waikato South	$9,149,834	$9,170,012	-0.2%
Western Bay of Plenty	$2,268,489	$2,259,327	0.4%
Eastern Bay of Plenty	$8,537,808	$8,536,664	0.0%
Taranaki	$18,171,764	$18,468,357	-1.6%
Manawatu-Wanganui	$3,870,662	$3,867,778	0.1%
Hawke’s Bay	$7,320,834	$7,027,632	4.2%
Wellington	$10,961,939	$11,047,480	-0.8%
Notional revenue	$95,956,500	$95,807,308	0.2%

Differences in price changes between regions reflect different CRF changes, the different contribution of the (unchanged) Throughput Fee, changes in non-standard prices and, in the case of Taranaki, the change to fully-variable pricing on the Frankley-Road pipeline.

Section 4 Consistency with Pricing Principles

Regulatory requirement

*2.4.3(2) Demonstrate the extent to which the pricing methodology is consistent with the **pricing principles** and explain the reasons for any inconsistency between the pricing methodology and the **pricing principles**;*

4.1. Pricing principles

The Pricing Principles specified in clause 2.5.2 of the Input Methodologies are:

2) Prices are to signal the economic costs of service provision, by-
   a) being subsidy free, that is, equal to or greater than incremental costs and less than or equal to standalone costs, except where subsidies arise from compliance with legislation and/or other regulation;
   b) having regard, to the extent practicable, to the level of available service capacity; and
   c) signalling, to the extent practicable, the effect of additional usage on future investment costs.
3) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall is made up by prices being set in a manner that has regard to consumers' demand responsiveness, to the extent practicable.
4) Provided that prices satisfy (1) above, prices are responsive to the requirements and circumstances of consumers in order to-
   a) discourage uneconomic bypass; and
   b) allow negotiation to better reflect the economic value of services and enable consumers to make price/quality trade-offs or non-standard arrangements for services.
5) Development of prices is transparent, promotes price stability and certainty for consumers, and changes to prices have regard to the effect on consumers

4.2. Principle #1: Economic costs of service provision

4.2.1. Subsidy-free pricing

Prices are said to be "subsidy-free" when they are not less than incremental cost (IC) and are not greater than stand-alone cost (SAC). Incremental costs for a consumer (or group of consumers) are those costs that are only incurred because of that consumer's (or group of consumers') connection to and use of the gas transmission system. Stand-Alone Cost is the cost of a gas transmission system providing service to just that consumer (or group of consumers).

The revenue allowed under the GDPP includes an allowance for certain costs (such as administration costs) that is based on an allocation of common and shared costs across Vector's regulated businesses rather than an estimate of such costs on a stand-alone basis. This means that the SAC for the provision of gas transmission services is higher than the ANR. It also means that, in aggregate, prices set to recover the ANR are, by definition, less than the SAC for the provision of gas transmission services.

At a theoretical level, demonstrating that prices are subsidy-free requires the GTB to demonstrate that, for every consumer and every consumer group, the price charged is not less than the incremental cost, nor greater than the SAC of supplying that consumer or consumer group.

Stand-alone cost

Stand-alone cost (SAC) is normally defined as the cost of providing a service or a group of services and nothing else. In a perfectly competitive market, goods are completely substitutable, so the cost of the alternative is the cost of obtaining exactly the same good or service elsewhere. In the context of gas transmission, this would require the construction of another gas transmission pipeline. In a workably competitive market however, goods are not necessarily completely substitutable, and an alternative energy or fuel source might provide an equivalent service. In the case of gas (which is a discretionary fuel), consumers can choose from a number of alternative sources of delivered energy.

Pricing up to the cost of a dedicated pipeline built specifically for a particular group of consumers is likely to result in prices that are much higher than the true cost of the alternative for many users, and would likely lead to disconnection. In practice, estimating the 'true' upper bound on prices requires information on the costs and bypass options of its consumers (an alternative fuel or an alternative transmission connection, if practicable).

To establish the appropriate upper bound for prices at each Connection Point, Vector adopted the lesser of:

- the traditional "alternative network" SAC; and
- the SAC of providing the same delivered energy from an alternative fuel source (we refer to this as the "alternative fuel SAC").

It is important to note that SAC was estimated at individual CPs and not at all combinations of CPs. In that respect the SAC can only be a guide. In some instances other network solutions might yield a lower SACs across a combination of CPs, and a more thorough investigation could be appropriate as part of the non-standard contracting process (see Section 5).

Alternative network SAC

The alternative network SAC represents a dedicated theoretical transmission system which could provide the same transmission service to a single Connection Point. The alternative network SAC includes a return on and of all network and non-network assets, indirect costs, maintenance costs, compressor and heater fuel costs. The SAC analysis is a highly complex exercise involving the construction of hypothetical networks to provide service to each consumer or consumer group – this is a highly labour-intensive exercise that generally (but not always) yields an average SAC higher than the SAC for the system as a whole.[1]

[1] Because of the economies of scale inherent in a gas transmission network, the average SAC for a consumer will generally be greater than the average SAC for a group of consumers, which in turn will generally be greater than the average SAC for the whole network. If prices are less than the SAC for the whole network, they are likely to be less than SAC for any given consumer or group of consumers. The exception to this may be where a large consumer is located close to the gas transmission line and it would be viable to bypass the existing gas transmission system. This is addressed separately under Pricing Principle 3.

Theoretical transmission system assets: The assets (System Fixed Assets, or SFA) for each Connection Point are assumed to be a stand-alone network between the current receipt point and the Connection Point. The assets consist of:

- a single pipeline following the same route as the existing one but sized only to supply the Connection Point
- one or more DPs sized to supply the current Maximum Design Flow at the connection point

The theoretical pipe size is estimated by means of a simplified (steady-state) gas flow formula.

Replacement cost of theoretical transmission network assets: The replacement cost of network assets is based on the annualised SAC pipeline and Delivery Point replacement cost rates. An average allocation of all other network assets including special feature costs, easement costs, compressor and all other types of stations costs are included in the pipeline replacement cost rate.

Replacement cost of theoretical non network assets: An estimate of the non-network assets (or Non System Fixed Assets (NSFA)) is based on the NSFA of the GTB. Each Connection Point is allocated a replacement cost equal to the total NSFA value of the GTB divided by the total number of Connection Points.

Expenses are comprised of indirect costs, fuel costs, and maintenance costs:

- *Indirect costs*: An estimate of the indirect costs for the connection Point is based on the total indirect costs of the GTB. Each Connection Point is allocated an indirect cost equal to the total indirect costs of the GTB divided by the total number of Connection Points.
- *Fuel costs*: Compressor and heater fuel costs are determined by multiplying the derived compressor and heater fuel rates with the total volume at the connection Point. These costs only apply if the Connection Point has been identified as requiring compression and/or heating.
- *Maintenance costs*: Maintenance on network assets is determined by multiplying the derived maintenance rate for all assets with the total replacement cost of the theoretical system.

Alternative fuel SAC

The approach to calculating the alternative fuel SAC was described in Section 2.2.

Incremental cost

The incremental costs (IC) of each Connection Point are determined by exactly the same “but for” test that is used to identify Connection Costs. Two estimates of IC are calculated: short run incremental costs (SRIC) and long run incremental costs (LRIC). The SRIC include compressor fuel, heater fuel and maintenance on the dedicated assets identified by means of the “but for” test. The LRIC includes the SRIC plus a return on and return of the dedicated assets identified by means of the “but for” test. The relationship between Connections Costs, Incremental Costs, and Directly Attributable Costs is:

Connection Costs = Long Run Incremental Costs = Costs Directly Attributable

If consumers are paying a price at least equal to SRIC then they are covering the immediate direct costs incurred in supplying them with gas, and in the short term it is beneficial to retain those consumers. Over the longer term consumers should pay a price at least equal to LRIC so that they cover the full cost of providing supply, including the cost of the assets required to connect to the wider system.

Application of the test

As described in section 2.2, as part of the price-setting process the GTB compares proposed prices against the least-cost alternative, whether that is a standalone network or an alternative energy source such as coal or bottled LPG.

The GTB cross-checks the individual revenue at each DP based on provisional prices. This allows an assessment of the extent to which uniform CRFs within transmission pricing zones may result in revenues outside the IC-SAC band at individual DPs. This is illustrated in Figure 18.

Prices at some CPs have historically been less than IC. While the overall framework for pricing has improved alignment with the Pricing Principles, there are however a number of CPs where the reduction in prices has either worsened the extent to which prices are below incremental costs, or has moved prices previously in the subsidy free range to a point below incremental costs. Generally the revenue from these DPs is low and we propose further work targeted at assessing each CP and the potential mitigations that may be employed.

Figure 18 Revenues from prices by CP and subsidy free ranges

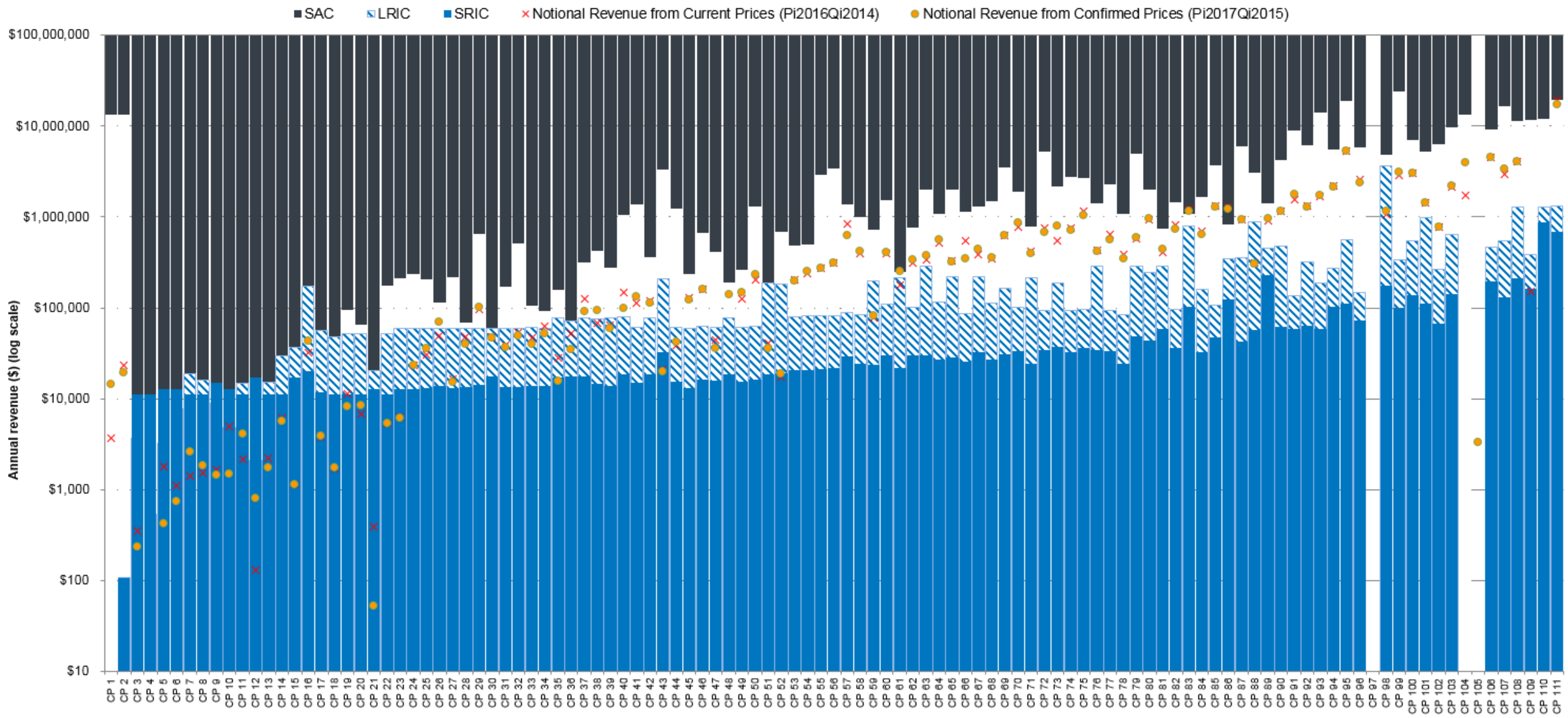
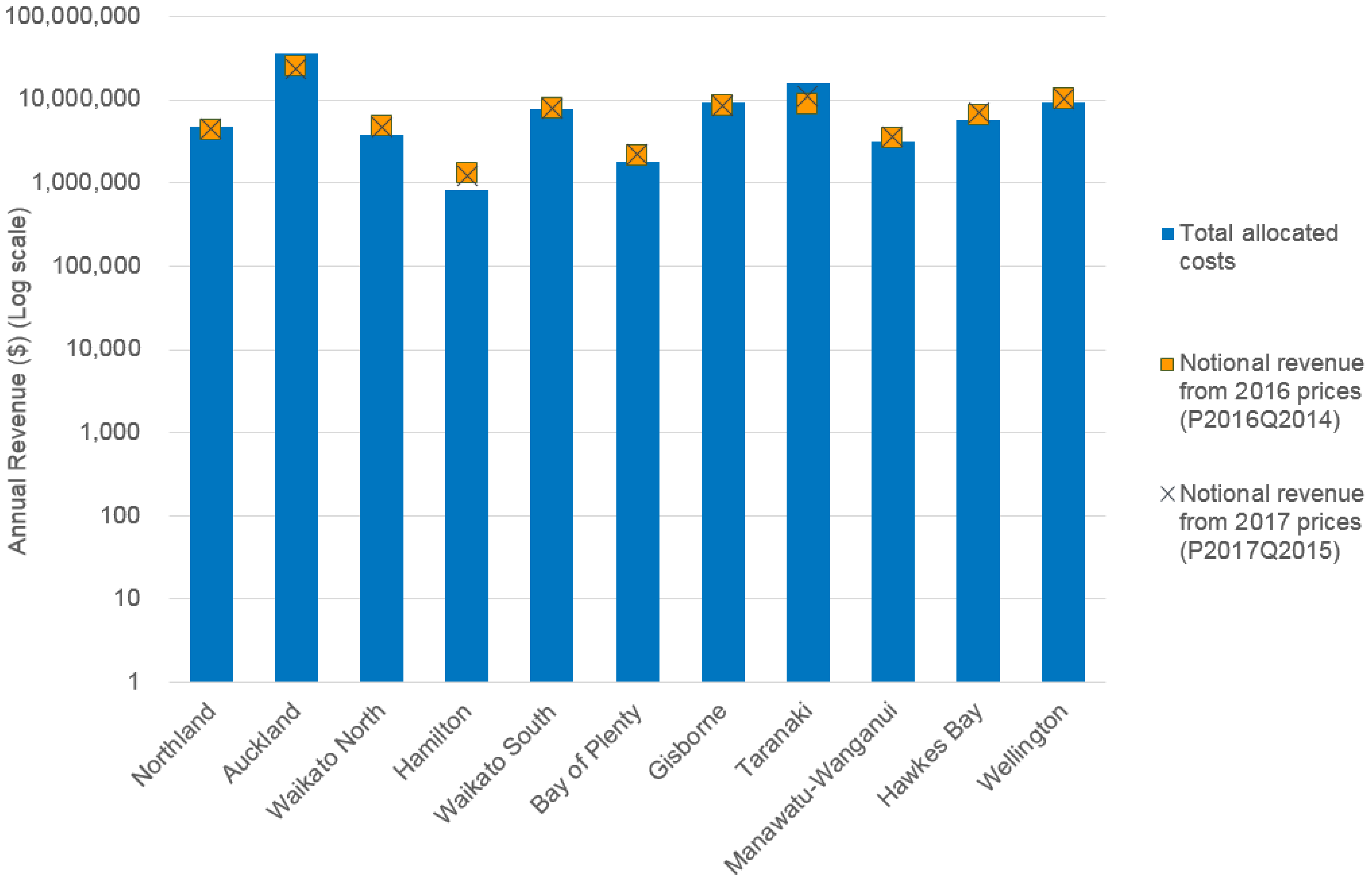


Figure 19 Revenues from prices by Pricing Region



4.2.2. Available service capacity and future investment costs

Closure of the Southdown and Otahuhu B power stations in 2015 effectively removed any constraint on the transmission system as far as Greater Auckland. The Northland section of the transmission system continues to be constrained however, in that the Marsden Point oil refinery is unable to take as much gas as it would like. A compressor station is currently under construction at Henderson in order to address that unmet need.

There are “emerging” constraint in the Waikato North region, to the extent that some consumers who might prefer to switch from coal to gas are currently unable to do so due to a lack of transmission capacity. First Gas is investigating investment options to address these issues.

In other regions there currently no constraints on available transmission capacity that impact on the economic cost of service provision. Indeed, given the level of available service capacity, it is appropriate that pricing is set in a manner that encourages greater use of the gas transmission system in these areas.

4.3. Principle #2: Recovery of any shortfall

Pricing Principle 2 requires that:

Where prices based on ‘efficient’ incremental costs would under-recover allowed revenues, the shortfall is made up by prices being set in a manner that has regard to consumers’ demand responsiveness, to the extent practicable.

Recovery of any shortfall in a manner that “has regard to consumers’ demand responsiveness” suggests the application of Ramsey Pricing. While Ramsey Pricing (which involves pricing higher to those less price responsive) is a useful and well accepted guideline for the recovery of allowed revenues above IC, it is extremely difficult to apply in practice as the information required (meaningful demand responsiveness information) is not readily available. It is also worth emphasising that even if the GTB knew something about the demand responsiveness of consumers, the GTB contracts with Shippers (together with large directly connected consumers) and is therefore generally not able to price discriminate across consumer groups based on demand elasticities. This information can be used however to inform the approach to non-standard contracts which use an estimated bypass cost as a guide (see Section 5).

Given the practical difficulties inherent in implementing a Ramsey pricing approach, the GTB has instead sought to recover any revenue shortfall in as least-distortionary manner as possible. The GTB considers that this captures the intent of Pricing Principle #2. Accordingly, the cost of shared assets has been allocated using Maximum Flow as an allocator, which reflects the underlying cost driver for the network. The resulting cost allocations provide improved incentives to utilise the existing gas transmission system in areas that were disadvantaged by the previous distance-based regime. Further, prices have been set on a regional basis to ensure there are no incentives to “game” capacity reservations between neighbouring DPs.

4.4. Principle #3: Responsive to requirements of consumers

4.4.1. Prices discourage uneconomic bypass

Discouraging uneconomic bypass is an extremely important commercial objective for the GTB. Gas transmission services must compete with alternative fuel and energy sources such as electricity, LPG, wood fires, coal, and solar heating.

Traditionally this principle has been interpreted to mean that prices should not be so high for any consumer that it becomes economic for a competitor to supply that consumer using an alternative *network* supply. This principle is based on the economic rationale that it is more efficient for one natural monopoly gas network to serve all consumers itself because of economies of scale/density. If another network tried to compete with the gas network side-by-side it would be less efficient as the economies of scale for those consumers would be lost and total cost would increase.

However, uneconomic bypass may also occur where a consumer uses an alternative energy source instead of natural gas and the incremental social costs of the alternative are higher than the incremental social costs of using the gas transmission system. Alternative energy sources were included in the development of SACs and considered in the development of standard prices. Notwithstanding this uneconomic bypass may still occur. Where the GTB becomes aware of such instances (for example, through an approach from the consumer), it may address them through the application of non-standard prices as described in 4.4.2 below.

4.4.2. Negotiation for non-standard prices

The GTB considers that the best way to allow consumers to negotiate differing levels of economic value from a service or to mitigate against uneconomic bypass is through non-standard contracts. Large consumers are able to negotiate with the GTB for different terms and conditions as long as it is commercially viable and possible for the GTB to provide the service.

Typical examples of consumers negotiating to realise economic value of different specific service include reinforcement of the network to allow for greater capacity and the installation and management of specialist equipment and connections. Contracts have been negotiated on non-standard pricing structures to allow consumers to manage their risk, including adjustment in prices to allow for atypical demand loads (e.g. seasonal use patterns) or a preference for pricing that is largely, if not wholly, fixed.

Please refer to Section 5 for the GTB’s policy regarding pricing for non-standard contracts.

4.5. Principle #4: Pricing process

Regulatory requirement

Development of prices is transparent, promotes price stability and certainty for consumers, and changes to prices have regard to the effect on consumers

The development of the current GTPM was subject to a lengthy consultation process, described in Section 1.5. This was considered to be an important part of compliance with Pricing Principle #4.

4.5.1. Development of prices is transparent

The current GTPM was developed in a transparent manner with consumer consultation conducted at regular intervals. It is considered appropriate based on feedback.

Within the GTPM costs are clearly identified and allocated on an appropriate and transparent basis.

4.5.2. Price stability and certainty

The GTPM reduces the likelihood that changes in consumer behaviour will result in significant changes to cost allocations between Connection Points. The use of Pricing Regions also eliminates the opportunity for arbitrage between Connection Points. Together, these changes mean that prices will be more stable over time.

4.5.3. Effect on consumers

The GTB is particularly conscious of the effect of its pricing on consumers and seeks to implement a pricing structure that provides appropriate incentives for consumers to connect to the gas transmission system and continue to use natural gas.

As noted previously, First Gas has adopted the GTPM developed by Vector after purchasing the GTB, and is proposing only very small changes to prices in the 2016/17 pricing year. These decisions reflect a desire to provide our customers with stability until a new transmission code and pricing methodology are introduced.

Section 5 Pricing for non-standard contracts

This section describes the approach to setting prices for non-standard contracts.

5.1. Extent of non-standard contracts

*2.4.5(1) Describe the approach to setting **prices** for **non-standard contracts**, including-*

*(a) the extent of **non-standard contract** use, including the value of **target revenue** expected to be collected from **consumers** subject to **non-standard contracts**;*

In certain circumstances published standard prices may not adequately reflect the actual costs of supplying a consumer, reflect the economic value of the service to the consumer or address the commercial risks associated with supplying that consumer. In addition to standard published prices, the GTPM also covers non-standard transmission agreements, ie supplementary agreements, as follows:

a) Supplementary agreements – a bi-lateral agreement between the GTB and a Shipper that amends parts of the VTC and provides firm transmission capacity for the purposes of delivery of gas to:

    i. A specific consumer and/or specific site; or

    ii. A specific Delivery Point.

b) Interruptible agreements – a form of supplementary agreement under which the capacity provided is fully interruptible.

These contracts allow tailored or specific prices and contractual terms to be applied to individual points on the transmission system.

There are 35 non-standard contracts[2]. Their estimated charges represent just under 30% of Target Revenue for 2016/17.

5.2. Criteria for non-standard contracts

*2.4.5(1)(b) Describe the approach to setting **prices** for **non-standard contracts**, including-*

*how the **GTB** determines whether to use a **non-standard contract**, including any criteria used;*

Vector published a policy that provided a general guide to the steps to be taken and factors to be considered when deciding whether or not to offer a non-standard contract (supplementary agreement) on the transmission system. This document (Supplementary Agreements Policy (March 2012)) can be found on OATIS at:

https://www.oatis.co.nz/Ngc.Oatis.UI.Web.Internet/Common/Publications.aspx

First Gas is maintaining this policy pending the development of a new transmission code and GTPM.

[2] This includes: supplementary agreements which apply the standard CRF and TPF for the relevant DP as well as those that don't (including where there are no standard prices for the relevant DP); all interruptible agreements (including those that apply published standard prices); and all "deemed" contracts on the Frankley Road pipeline, ie where Shippers are charged the throughput fee for that pipeline.

5.3. Methodology for non-standard prices

*2.4.5(1) Describe the approach to setting **prices** for **non-standard contracts**, including-*

*(c) any specific criteria or methodology used for determining **prices** for **consumers** subject to **non-standard contracts**, and the extent to which these criteria or that methodology are consistent with the **Pricing Principles**;*

The prices for non-standard contracts are set to reflect the circumstances of the specific Shipper/consumer. In all cases prices are tested to ensure they are not less than incremental cost and not greater than standalone costs.

When a non-standard contract is due for renewal, pricing is re-assessed to determine whether non-standard prices should continue to apply.

The flexible approach to pricing for non-standard contracts ensures that compliance with the Pricing Principles is enhanced, as demonstrated in Figure 20 below.

Figure 20 Compliance of non-standard pricing with the Pricing Principles

Pricing principle	Extent of compliance without non-standard pricing	Extent of compliance with non-standard pricing
1) Prices are to signal the economic costs of service provision, by- a) being subsidy free, that is, equal to or greater than incremental costs and less than or equal to standalone costs, except where subsidies arise from compliance with legislation and/or other regulation;	Prices are subsidy-free	Prices remain subsidy-free
b) having regard, to the extent practicable, to the level of available service capacity; and c) signalling, to the extent practicable, the effect of additional usage on future investment costs.	There are no capacity constraints to reflect in current pricing. Price structure is set to generally encourage use of spare capacity. However, some spare capacity may be unused in the absence of non-standard pricing if the consumer disconnects from the gas transmission system.	Compliance *enhanced* because non-standard pricing ensures that consumers that would otherwise disconnect from the gas transmission system will remain connected, use available capacity that would otherwise be unutilised. These consumers will continue to pay some portion of the shared costs of the gas transmission system at least equal to or above incremental costs, providing a benefit to all connected parties.

Pricing principle	Extent of compliance without non-standard pricing	Extent of compliance with non-standard pricing
2) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall is made up by prices being set in a manner that has regard to consumers' demand responsiveness, to the extent practicable.	If a consumer disconnects because standard prices exceeded their "reservation cost" then those prices did not reflect the demand-responsiveness of that consumer.	Compliance is *enhanced* because the demand-responsiveness of a price-sensitive consumer has been taken into account by the non-standard pricing.
3) Provided that prices satisfy (1) above, prices are responsive to the requirements and circumstances of consumers in order to- a) discourage uneconomic bypass; and b) allow negotiation to better reflect the economic value of services and enable consumers to make price/quality trade-offs or non-standard arrangements for services.	All prices are subsidy-free so meet (1) above. Prices have been explicitly set to account for the cost of alternative sources of energy for the average consumer in a category, but do not account for the specific circumstances of all consumers.	Prices continue to be subsidy-free so meet (1) above. Compliance is *enhanced* because non-standard pricing allows differential prices to be set for the specific consumers where bypass is viable or would otherwise be uneconomic. Compliance is enhanced because non-standard pricing allows prices for gas transmission services to be customised to reflect the economic value of gas transmission services to specific consumers, and allows the consumer to make quality/price trade-offs.
4) Development of prices is transparent, promotes price stability and certainty for consumers, and changes to prices have regard to the effect on consumers		Compliance is *enhanced* because allowance can be made for the effect on particular consumers whose circumstances make them more sensitive to prices.

5.4. Obligations in respect of service interruptions

(2) Describe the ***GTB****'s obligations and responsibilities (if any) to* ***consumers*** *subject to* ***non-standard contracts*** *in the event that the supply of* ***gas transmission services*** *to the* ***consumer*** *is interrupted. This description must explain-*

(a) the extent of the differences in the relevant terms between ***standard contracts*** *and* ***non-standard contracts****;*

(b) any implications of this approach for determining ***prices*** *for* ***consumers*** *subject to* ***non-standard contracts****.*

The GTB's obligations in respect of the provision of transmission capacity under (standard) transmission services agreements and (non-standard) supplementary agreements (excluding interruptible agreements) are identical.

That is to say, transmission capacity provided under Shippers' transmission services agreements (reserved capacity) ranks equally with firm capacity provided under supplementary agreements (supplementary capacity) in the event of any emergency or other event affecting the relevant part(s) of the transmission system.

The VTC requires the GTB to use all reasonable endeavours to curtail consumers on interruptible agreements before restricting Shippers' reserved capacity or supplementary capacity.

The main difference between firm transmission capacity and interruptible capacity is the probability of curtailment. Firm capacity may only be curtailed as the result of an emergency (unless the Shipper is in overrun), whereas interruptible capacity may be interrupted at any time.

A Shipper whose firm capacity is curtailed will normally be entitled to a rebate fixed transmission fees.

A Shipper using interruptible capacity will not be charged to the extent of the interruption.

Section 6 Compliance matrix

The table below is included to demonstrate how this disclosure complies with the Gas Transmission Information Disclosure 2012.

2.4.1 Every **GTB** must **publicly disclose**, before the start of each **pricing year**, a pricing methodology which-	See individual clauses below.
(1) Describes the methodology, in accordance with clause 2.4.3, used to calculate the **prices** payable or to be payable;	Section 3
(2) Describes any changes in **prices** and **target revenues**;	Section 3
(3) Explains, in accordance with clause 2.4.5 of this section, the approach taken with respect to pricing in **non-standard contracts**; and	Section 5
(4) Explains whether, and if so how, the **GTB** has sought the views of **consumers**, their expectations in terms of **price** and quality, and reflected those views in calculating the **prices** payable or to be payable. If the **GTB** has not sought the views of **consumers**, the reasons for not doing so must be disclosed.	Section 4.5.3
2.4.2 Any change in the pricing methodology or adoption of a different pricing methodology, must be **publicly disclosed** at least 20 working days before **prices** determined in accordance with the change or the different pricing methodology take effect.	N/A
2.4.3 Every disclosure under clause 2.4.1 of this section must-	See individual clauses below.
2.4.3(1) Include sufficient information and commentary for interested persons to understand how **prices** were set for **consumers**, including the assumptions and statistics used to determine **prices** for **consumers**;	Section 3
2.4.3(2) Demonstrate the extent to which the pricing methodology is consistent with the **Pricing Principles** and explain the reasons for any inconsistency between the pricing methodology and the **Pricing Principles**;	Section 4

2.4.3(3) State the **target revenue** expected to be collected for the **pricing year** to which the pricing methodology applies;	Section 3.4.1
2.4.3(4) Where applicable, identify the key components of **target revenue** required to cover the costs and return on investment associated with the **GTB**'s provision of **gas transmission services**. Disclosure must include the numerical value of each of the components;	Section 3.3.1
2.4.3(5) If **prices** have changed from **prices** disclosed for the immediately preceding **pricing year**, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Section 3.5
Revenue by Consumer Group 2.4.3(6) Where applicable, describe the method used by the **GTB** to allocate the **target revenue** among **consumers**, including the numerical values of the **target revenue** allocated to **consumers** and the rationale for allocating it in this way;	Section 3.4.3
Revenue by Price Component 2.4.3(7) State the proportion of **target revenue** (if applicable) that is collected through each **price component** as **publicly disclose**d under clause 2.4.18.	Section 3.4.4
Effect of Pricing Strategy 2.4.4 Every disclosure under clause 2.4.1 above must, if the **GDB** has a **pricing strategy**- (1) Explain the **pricing strategy** for the next 5 **pricing years** (or as close to 5 years as the **pricing strategy** allows), including the current **pricing year** for which **prices** are set; (2) Explain how and why **prices** are expected to change as a result of the **pricing strategy**; (3) If the **pricing strategy** has changed from the preceding **pricing year**, identify the changes and explain the reasons for the changes.	First Gas inherited the current GTPM from Vector, and has used it in the determination of transmission prices for 2016/17.
Prices for Non-Standard Contracts	

2.4.5 Every disclosure under clause 2.4.1 above must-	
(1) Describe the approach to setting **prices** for **non-standard contracts**, including-	Section 5
(a) the extent of **non-standard contract** use, including the value of **target revenue** expected to be collected from **consumers** subject to **non-standard contracts**;	Section 5.1
(b) how the **GTB** determines whether to use a **non-standard contract**, including any criteria used;	Section 5.2
(c) any specific criteria or methodology used for determining **prices** for **consumers** subject to **non-standard contracts**, and the extent to which these criteria or that methodology are consistent with the **Pricing Principles**;	Section 5.3
(2) Describe the **GTB**'s obligations and responsibilities (if any) to **consumers** subject to **non-standard contracts** in the event that the supply of **gas transmission services** to the **consumer** is interrupted. This description must explain-	Section 5.4
(a) the extent of the differences in the relevant terms between **standard contracts** and **non-standard contracts**;	
(b) any implications of this approach for determining **prices** for **consumers** subject to **non-standard contracts**.	

Appendix 1 Glossary

Act: the Commerce Act 1986.

Allowable Notional Revenue: the revenue First Gas is allowed to earn during the pricing year under the GDPP.

Connection Point (CP): an aggregation of one or more Delivery Points (DPs) for cost allocation purposes.

COSM: Cost of Supply Model.

CPI: the Consumer Price Index.

CRF: Capacity Reservation Fee, a charge applied for each GJ of reserved capacity.

Delivery Point or **DP:** means a point at which a Shipper's gas is taken (or made available to be taken) from a pipeline into another transmission pipeline (whether owned by the GTB or another party), a gas consuming facility or a distribution network.

Determination: the Gas Information Disclosure Determination, Decision NZCC24, 1 October 2012.

GDPP: the Gas Transmission Services Default Price-Quality Path Determination 2013, NZCC5, 28 February 2013.

GJ: Gigajoule, a unit of energy.

GTB: the gas transmission business, meaning Vector prior to 20 April 2016 and First Gas Limited thereafter.

GTPM: Gas Transmission Pricing Methodology.

Incremental Cost (IC): the cost of providing a defined service to an additional consumer or group of consumers given that service is already provided to other consumers.

Input Methodologies: the Gas Transmission Services Input Methodologies Determination 2010 (Commerce Commission Decision 712, 22 December 2010.

Maximum Flow: the peak flow rate or capacity of a transmission asset (eg pipeline or DP) or Connection Point.

MPOC: Maui Pipeline Operating Code.

NGC: Natural Gas Corporation.

NSFA: Non-system fixed assets.

Price Component: the various tariffs, fees and charges that constitute the components of the total price paid, or payable, by a consumer.

Pricing Principles: the pricing principles specified in clause 2.5.2 of the Gas Transmission Services Input Methodologies Determination 2010 (Commerce Commission Decision 712, 22 December 2010).

Pricing Region: a group of Delivery Points with the same CRF (as set out in section 3.1); not the same as a "Transmission Pricing Zone" as defined in the VTC.

Pricing Strategy: a decision made by the Directors of the GTB on the GTB's plans or strategy to amend or develop prices in the future, and recorded in writing.

SFA: System Fixed Assets.

Shippers: A person named as a shipper in a Transmission Services Agreement with First Gas.

Stand Alone Cost (SAC): the cost of providing a defined service or group of services to a particular consumer or group of consumers, without providing any other services or serving any other consumers.

Target revenue: the revenue the GTB expects to receive during the pricing year, as described in section 3.4.1.

TOU: Time of use.

TPF: Throughput fee, a charge applied to each GJ of gas delivered at a DP.

VTC: the Vector Transmission Code.