Pricing Methodology for Gas Transmission Services

From 1 October 2019

Pursuant to the Gas Transmission Information Disclosure Determination 2012

Update as of 31 March 2020

Please note that from 1 April 2020 to 30 September 2020, the MPOC and VTC pricing structure will remain in place. Refer to our pricing schedules under these two commercial codes.

First Gas Limited
September 2019

Introduction

First Gas operates 2,500 kilometres of gas transmission pipelines (including the Maui pipeline), and more than 4,700 kilometres of gas distribution pipelines across the North Island. These gas infrastructure assets transport gas from Taranaki to major industrial gas users, electricity generators, businesses and homes, and supply around 20 percent of New Zealand's primary energy needs.

For further information on First Gas, please visit our website www.firstgas.co.nz.

The First Gas Group also owns energy infrastructure assets across New Zealand through our affiliate Gas Services NZ Limited (GSNZ), a separate business with common shareholders that owns the Ahuroa gas storage facility and Rockgas. These businesses were both added to the Frist Gas Group in the past 12 months, providing valuable perspectives from different parts of the gas supply chain for our regulated transmission business.

The Ahuroa gas storage facility (trading as Flex Gas) can store up to 18PJ of gas, with expansion planned over the next two years to increase the injection and withdrawal rates of the facility. Visit the website www.flexgas.co.nz. Rockgas has over 80 years' experience providing LPG to 100,000 customers throughout New Zealand. Visit the website www.rockgas.co.nz

Information disclosure

This document is the pricing methodology for gas transmission services prepared pursuant to clause 2.4 of the *Gas Transmission Information Disclosure Determination 2012* (consolidating all amendments as at 3 April 2018), issued by the Commerce Commission on 3 April 2018 (the ID Determination).

This Pricing Methodology covers the 12-month pricing year from 1 October 2019. The pricing year has been divided into 2 six-month periods, reflecting the proposed implementation of the Gas Transmission Access Code (GTAC) on 1 April 2020.

The following documents are provided with this Pricing Methodology:

- Maui pipeline pricing methodology (applies from 1 October 2019 to 31 March 2020);
- Non-Maui pipeline pricing methodology (applies from 1 October 2019 to 31 March 2020);
- Gas Transmission Access Code pricing methodology (applies from 1 April 2020 to 30 September 2020); and
- Director certification covering the 12 months pricing year from 1 October 2019.

This Pricing Methodology was prepared on 12 September 2019.

Further information

For further information regarding this Pricing Methodology, please contact:

Karen Collins
Regulatory Policy Manager
First Gas Limited
Karen.Collins@firstgas.co.nz
04 979 5368

Disclaimer

For presentation purposes, some numbers in this document have been rounded. This may cause small discrepancies or rounding inconsistencies when aggregating some of the information presented in the document. These discrepancies do not affect the overall calculations which are based on more detailed information.

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1 Approach to pricing methodologies for GY2020

For the pricing year commencing 1 October 2019 (gas year, GY2020), First Gas has elected to continue to apply the existing pricing methodologies for the Maui and Non-Maui gas transmission systems for the first six months of the year (ending on 31 March 2020). First Gas will then apply the new Gas Transmission Access Code (GTAC) pricing methodology for the second six months of the year (beginning on 1 April 2020). While these apply different methodologies, we have incorporated them into one disclosure document because First Gas has a single regulated revenue cap for our Gas Transmission Business (GTB).

Continuation of existing pricing methodologies and introduction of GTAC pricing methodology

First Gas has been working with stakeholders on the implementation of a single transmission code, the Gas Transmission Access Code (GTAC). The GTAC IT systems are still under development and the GTAC is expected to come into force on 1 April 2020.

First Gas will retain the structure of the prices under the Maui Pipeline Operating Code (MPOC) and Vector Transmission Code (VTC) for the first six months of the year beginning 1 October 2019. There have been no pricing structure changes for the MPOC or the VTC. MPOC prices are unchanged from GY2019. VTC prices have been adjusted to reflect the lower level of capacity reservations requested by shippers under that code.

First Gas will apply the GTAC pricing methodology when the GTAC comes into force, which is expected to be 1 April 2020. First Gas consulted on the GTAC pricing methodology in 2019 and issued a final methodology on 30 June 2019. This pricing methodology and notified prices will apply for the second six months of GY2020.

The revenue earned from transmission services provided under the MPOC, VTC and GTAC has been updated to reflect changes in allowable revenue, and forecast transmission quantities, pass-through and recoverable costs.

Consolidation into a single disclosure document

The MPOC, VTC and GTAC methodologies are presented together in this document. This reflects the fact that the regulatory control under the current Default Price-Quality Path (DPP) applies to our GTB as a whole (i.e. including both Maui and non-Maui systems for the entire pricing year), and we are required to demonstrate that our prices for GY2020 comply with this revenue cap.

Consultation on the final pricing for GY2020

The decision to delay the implementation of GTAC was taken in consultation with First Gas customers, who also worked with us to decide on the pricing approach for GY2020 prior to the implementation of GTAC. Consultation steps included:

- 31 July: Workshop on GTAC implementation status;
- 2 August: Release of decision to delay GTAC pricing options and draft of VTC change requests;
- 12 August: Release of further detail on pricing options prior to the GTAC;
- 20 August: Workshop to discuss pricing options and develop a solution to apply until the GTAC comes into force. Timeframe for pricing and VTC change request to facilitate pricing changes agreed;
- 21 August: VTC draft change request notification released;
- 23 August: VTC draft change request released and confirmed VTC capacity reservation fees released;
- 28 August: Deadline for submissions on draft VTC change request;
- 30 August: Final change request issued;
- 5 September: VTC change request approved/effective;
- 6 September 2019: Shippers notified their confirmed capacity reservations for the period up until 1 April 2020; and
- 11 September 2019: First Gas notified confirmed TPFs and approval of confirmed capacity reservations.

2 Compliance with revenue cap for GTB

First Gas' GTB is required to set prices to recover an amount no greater than the Forecast Allowable Revenue (FAR) under the current DPP (2017 – 2022). Compliance with the FAR requirement is determined by ensuring the GY2020 prices multiplied by the forecast GY2020 quantities (the Target Revenue) is less than or equal to the FAR. From 1 October 2017, First Gas has needed to comply with a single revenue cap, covering both the Maui and non-Maui transmission pipelines.

Target Revenue for the GY2020 pricing year and our compliance with the FAR is set out in Table 1 below. First Gas is compliant with its DPP revenue cap.

Table 1: Determining Target Revenue

	Amount			
	1 Oct 2019 – 31 Mar 2020	1 Apr 2020 – 30 Sep 2020	Total	Proportion of Target Revenue
Forecast Net Allowable Revenue	$126,456,000		$126,456,000	
Forecast pass-through and recoverable costs	$1,252,032	$2,041,627	$3,293,659	
Forecast Allowable Revenue (FAR)	**$129,749,659**		**$129,749,659**	
Target Revenue				
Standard MPOC revenue for the period 1 October 2019 to 31 March 2020	$16,226,805		$16,226,805	12.5%
Standard VTC revenue for the period 1 October 2019 to 31 March 2020	$31,643,515		$31,643,515	24.4%
Standard GTAC revenue for period 1 April 2020 to 30 September 2020		$56,161,363	$56,161,363	43.3%
Non-Standard Pricing (SA and ICA Revenue)	$25,672,556		$25,672,556	19.8%
Total Target Revenue	**$129,704,239**		**$129,704,239**	**100%**
Compliance (Target Revenue ≤ FAR)	**Compliant**			

This FAR differs from the FAR reported in GTAC GY2020 TPM published on 30 June 2019. This is because the GTAC has different recoverable costs from those that apply under the MPOC and VTC regimes. The key differences are:

- Balancing incentives are stronger under GTAC, so we expect a higher quantity of balancing gas will be required in the first 6 months of GY2020 than previously forecast under the GTAC GY2020 TPM;
- The cash-out regime under the MPOC is maintained. Net cash-out revenues were forecast based on GY2018 volumes; and
- Excess Running Mismatch (ERM) charges are only payable during the second half of GY2020.

All other pass-through and recoverable costs remain the same between the two periods.

Table 2 identifies the key components of target revenue required to cover the costs and return on investment associated with the First Gas' provision of gas transmission services.

Table 2: Key components of target revenue

Cost Components	$	%
Operational expenditure	$39,341,101	30%
Pass through and recoverable costs	$3,293,659	3%
Depreciation	$26,941,673	21%
Tax	$15,812,000	12%
Return on capital	$44,315,806	34%
Target revenue	**$129,704,239**	

3 Forecast gas flows and reserved capacities

Gas flows were forecast for the GTAC GY2020 TPM published on 30 June 2019. This forecast forms the basis of all throughput volumes in this combined TPM, including the impact of announced production plant shutdowns at Kupe in November 2019 and Pohokura in March 2020. As the GTAC only runs for the second half of GY2020, an estimate of flows in each part of the GY2020 was required to establish the volumes under each contract. VTC capacity reservation estimates were also required.

Estimation of all other quantities (e.g. overruns and underruns) for the TPM followed the methodology in the relevant TPM pro-rated for a partial year.

GTAC gas flows from 1 April to 30 September 2020

Analysis of historic flows was undertaken to establish the seasonality of flows in the transmission system. This work established that 53% of flows occurred in the second half of a contract year (1 April to 30 September). The initial forecast from the GTAC GY2020 TPM was therefore pro-rated across all zones to estimate this seasonality.

Non-standard contract volumes were forecast as per the GTAC GY2020 TPM and pro-rated for half a year.

VTC gas flows from 1 October to 30 March September 2020

VTC throughput volumes (including volumes for the Frankley Road Line) were derived from the GTAC GY2020 TPM and reduced to 47% of the total to account for seasonality.

Capacity reservations for the VTC were based on final capacity bookings from customers received on 6 September 2019.

Additional non-standard contract volumes (i.e. contracts not required under GTAC) were forecast in the same manner as the VTC GY2019 TPM based on historic flows.

MPOC gas flows from 1 October to 30 March September 2020

MPOC throughput volumes for Tariff 2 were derived from the GTAC GY2020 TPM and reduced to 47% of the total to account for seasonality. As some small points were not accounted for explicitly in the GTAC GY2020 TPM forecast, historic values were used.

The throughput distance quantities for Tariff 1 were then determined using the same methodology as that outlined in the MPOC GY2019 TPM attached to this document.

4 Final Prices for GY2020

The previously published Transmission Pricing Methodologies (TPM) are the foundation of this document. All commentary, calculations, figures and discussion in them remain relevant unless stated otherwise here. Final pricing for GY2020 is reflective of the need to react to the delay to GTAC implementation. We have worked with customers to develop pricing that is equitable and provides a pragmatic solution in the face of the challenging timeframes involved. We would like to thank customers for their collaborative approach to the present situation.

MPOC prices to 31 March GY2020

The decision to delay implementation of the GTAC was made on 2 August 2019 following consultation with customers. The MPOC requires a 60-day timeframe for changing prices. There was therefore insufficient time to implement a price change under the MPOC to take effect from 1 October 2019. MPOC pricing for GY2020 is therefore unchanged from GY2019. Pricing is given in Table 3 below.

Table 3: GY2020 MPOC Prices

	Unit	2018/19	2019/20	Percentage Change
Tariff 1	$ / GJ.km	0.001601	0.001601	0%
Tariff 2	$ / GJ	0.073132	0.073132	0%

VTC prices to 31 March GY2020

Around 85% of VTC standard revenue comes from capacity reservations, which must be provided by shippers in September prior to the beginning of each gas year on 1 October. Capacity may be traded between pipelines and between customers, but the VTC restricts the ability of customers to cancel reserved capacity after booking. In booking capacity customers therefore consider the entire year of flow. As gas use is seasonal, capacity bookings tend to increase over the year to allow customers to deal with winter peaks.

The current extension of the VTC is only for a six-month period over the summer months. This approach has not been applied before, with previous reservations made for periods covering 12 months. Our expectation was for lower capacity bookings than previous years since the winter peak capacity did not have to be taken into account. We consulted with customers on how to deal with this issue in a way that ensures revenue recovery aligned with our revenue cap to avoid price instability in future years. We created several scenarios for capacity bookings, which concluded that low VTC capacity bookings could lead to under recovery by up to 5% over the year.

At the workshop on 20 August 2019 we agreed with our customers to a process to finalise capacity reservation fees and levels, before setting final Throughput Fees (TPFs) at delivery points with capacity bookings. This provided comfort to First Gas and customers that forecast revenue would align with our revenue cap. We increased Capacity Reservation Fees (CRFs) under the VTC by 8% to account for the expected decrease in capacity reservations. Following the release of these fees on 23 August 2019, customers provided their final capacity bookings which we then used to set final TPFs.

After receiving the final capacity bookings, we adjusted TPFs by $0.05/GJ. Fully variable VTC pricing at other locations (e.g. Frankley Rd) was maintained at GY2019 levels. This approach maintains the overall structure of the VTC where fixed capacity reservations account for most of First Gas' revenue, supplemented by variable charges and non-standard contracts. While the headline increase in TPFs seems high, VTC throughput revenue remains only 2.8% of our GY2020 revenue.

Table 4 summarises these changes.

Table 4: GY2020 VTC standard prices

Pricing Region	2018/2019		2019/2020		Percentage Change	
	TPF $/GJ	CRF $/GJ.MDQ	TPF $/GJ	CRF $/GJ.MDQ	TPF	CRF
Taranaki	$0.05	$81	$0.10	$87	100%	8%
Waikato South	$0.05	$356	$0.10	$384	100%	8%
Auckland	$0.05	$345	$0.10	$373	100%	8%
Northalnd	$0.05	$525	$0.10	$567	100%	8%
Waikato North	$0.05	$356	$0.10	$384	100%	8%
South Taranaki - Whanganui	$0.05	$335	$0.10	$362	100%	8%
Manawatu - Horowhenua	$0.05	$345	$0.10	$373	100%	8%
Hawkes Bay	$0.05	$356	$0.10	$384	100%	8%
Kapiti - Wellington	$0.05	$427	$0.10	$461	100%	8%
Waikato East	$0.05	$356	$0.10	$384	100%	8%
Bay of Plenty West	$0.05	$437	$0.10	$472	100%	8%
Bay of Plenty South	$0.05	$457	$0.10	$494	100%	8%
Bay of Plenty East	$0.05	$478	$0.10	$516	100%	8%
Eastland	$0.05	$498	$0.10	$538	100%	8%
Hamilton	$0.05	$165	$0.10	$178	100%	8%
Frankley Road	$0.29	n/a	$0.29	n/a	0%	0%

GTAC Prices 1 April to 30 September GY2020

GTAC pricing for GY2020 was set on 30 June 2019. GTAC pricing can only be changed on 30 June in the year preceding the next Gas Year. GTAC pricing for GY2020 is therefore unchanged from that published on 30 June 2019. Pricing is given in Table 5 below.

Table 5: GY2020 GTAC Prices

Code	Delivery Zone / Individual Delivery Point	DNC Fee ($/GJ)
NTHL	Te Tai Tokerau (Northland)	$2.20
AUCK	Tāmakimakaurau (Auckland)	$1.93
WKTN	Waikato ki te Raki (Waikato North)	$1.91
HMTN	Kirikiriroa (Hamilton)	$1.37
KING	Te Rohe Pōtae-Taupiri (King Country-Taupiri)	$1.91
WKTS	Waikato ki te Tonga (Waikato South)	$2.02
TNGA	Tauranga	$2.22
TAPO	Central Plateau	$2.22
WHAK	Whakatane	$2.25
EAST	Te Tai Rawhiti (Eastland)	$2.86
TKIE	Taranaki ki Uta (Inland Taranaki)	$0.42
TKIW	Taranaki ki Tai (Coastal Taranaki)	$0.42
ATEA	Aotea (South Taranaki-Whanganui)	$1.76
TRUA	Tararua (Manawatu-Horowhenua)	$1.84
HWKB	Kahungunu (Hawkes Bay)	$1.91
WGTN	Whanganui- a- tara / Kapiti (Kapiti-Wellington)	$2.05
BERD	Bertrand Road (Waitara Valley)	$0.12
FAUD	Faull Road	$0.12
HUPS	Huntly Power Station	$0.37
MAND	Mangorei Delivery Point	$0.11
NGRD	Ngatimaru Rd Delivery	$0.11

5 Regulatory compliance table

Table 6 demonstrates how the pricing methodologies comply with the Gas Transmission Information Disclosure Determination 2012.

Table 6: Compliance matrix

Principle	Reference / Description			
	Pricing methodology for Gas Transmission Services (MPOC - September 2018)	**Pricing methodology for Gas Transmission Services (VTC - September 2018)**	**Pricing methodology for Gas Transmission Services (GTAC - June 2019)**	**Pricing methodology for Gas Transmission Services (September 2019)**
2.4.1 Every **GTB** must **publicly disclose**, before the start of each **pricing year**, a pricing methodology which- (1) Describes the methodology, in accordance with clause 2.4.3, used to calculate the **prices** payable or to be payable;	Section 4	Section 4	Section 4	Section 4
(2) Describes any changes in **prices** and **target revenues**;	Section 4	Section 4	Sections 4 and 6.1	Section 4 (prices) and Section 2 (target revenues)
(3) Explains, in accordance with clause 2.4.5 of this section, the approach taken with respect to pricing in **non-standard contracts**; and	N/A Non-standard contracts do not exist for the MPOC	Section 6	Section 4.5	Refer to GTAC and VTC TPMs
(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 5.1	Section 5	Section 5	Section 1 and Section 4
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	N/A	The pricing methodology was publicly disclosed on 30 June 2019, 3 months prior to the prices taking effect.	This pricing methodology does not change our approach to pricing, but consolidates three approaches that were all notified ahead of the 20 working day notice period
2.4.3 Every disclosure under clause 2.4.1 of this section must-				

Principle	Reference / Description			
	Pricing methodology for Gas Transmission Services (MPOC - September 2018)	Pricing methodology for Gas Transmission Services (VTC - September 2018)	Pricing methodology for Gas Transmission Services (GTAC - June 2019)	Pricing methodology for Gas Transmission Services (September 2019)
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 4	Section 4	Section 4	Section 4
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 5	Section 5	Appendix 2	Refer to previous TPMs
2.4.3(3) State the **target revenue** expected to be collected for the **pricing year** to which the pricing methodology applies;	Section 4.4.1	Section 4.4.1	Section 2.1	Section 2
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	N/A Prices have been set subjectively so that price shocks in the transition to the GTAC GTPM are minimised.	See section 4.2.1	Section 2
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 1.4	Section 4.5	Section 6.1	Section 4
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 4	Section 4.4.1	Section 4	Section 4
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 disclosed** under clause 2.4.18.	Section 4	Section 4.4.2	Section 4, Table 3	Section 2
Effect of Pricing Strategy				

Principle	Reference / Description			
	Pricing methodology for Gas Transmission Services (MPOC - September 2018)	**Pricing methodology for Gas Transmission Services (VTC - September 2018)**	**Pricing methodology for Gas Transmission Services (GTAC - June 2019)**	**Pricing methodology for Gas Transmission Services (September 2019)**
2.4.4 Every disclosure under clause 2.4.1 above must, if the **GTB** 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.	N/A No pricing strategy exists for the Maui pipeline other than the move to new GTPM under the GTAC. This is due to the pricing methodology being prescribed within the MPOC.	First Gas applied the GTPM developed by Vector and has used it in the determination of transmission prices for 2018/2019. A new pricing methodology will be applied under the GTAC.	First Gas does not have a pricing strategy for prices set under the GTAC. First Gas intends to consult on a pricing strategy in 2020 in preparation for the TPM for GY 2022.	As per GTAC GY2020 TPM
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- (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**; (b) how the **GTB** determines whether to use a **non-standard contract**, including any criteria used; (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**;	N/A Non-standard contracts do not exist for the MPOC.	Section 6 Section 6.1 Section 6.2 Section 6.3	Section 4.5	As per GTAC GY2020 TPM
(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**.	N/A Non-standard contracts do not exist for the MPOC.	Section 6.4	Section 4.5.3	As per GTAC GY2020 TPM

6 Director certificate

Director certificate

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

Clause 2.9.2

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; and

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 Philippa Jane Dunphy	Director Euan Richard Krogh
12 September 2019	12 September 2019
Date	Date

Appendix 1: GY2019 Transmission Pricing Methodology

Pricing Methodology for Gas Transmission Services

From 1 October 2017

Pursuant to the Gas Distribution Information Disclosure Determination 2012

First Gas Limited
4 September 2017

1 Introduction

First Gas operates 2,500km of gas transmission pipelines (including the Maui pipeline), and more than 4,800km of gas distribution pipelines across the North Island. These gas infrastructure assets transport gas from Taranaki to major industrial gas users, electricity generators, businesses and homes, and transport around 20 percent of New Zealand's primary energy supply.

For further information on First Gas, please visit our website www.firstgas.co.nz.

Information disclosure

This document is the pricing methodology for gas transmission services prepared pursuant to clause 2.4 of the *Gas Transmission Information Disclosure Determination 2012* (consolidated in 2015), issued by the Commerce Commission on 24 March 2015 (the ID Determination).

This Pricing Methodology covers the 12-month pricing year from 1 October 2017.

The following documents are provided with this Pricing Methodology:

- Maui pipeline pricing methodology
- Non-Maui pipeline pricing methodology
- Director certification

This Pricing Methodology was prepared on 31 August 2017.

Further information

For further information regarding this Pricing Methodology, please contact:

Karen Collins
Regulatory Manager
First Gas Limited
Karen.Collins@firstgas.co.nz
04 979 5368

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1. Approach to pricing methodologies for 2017/18

For the pricing year commencing 1 October 2017, First Gas has elected to continue the existing pricing methodologies for the Maui and Non-Maui transmission systems, but has incorporated them into one disclosure document.

Continuation of two existing pricing methodologies

First Gas must retain the structure of the prices under the Maui Pipeline Operating Code (MPOC) and Vector Transmission Code (VTC) for the year beginning 1 October 2017. The single transmission code, the Gas Transmission Access Code (GTAC), is still under development and will not come into force until 1 October 2018. The current pricing methodologies therefore will continue to apply for 2017/18 and have been updated to reflect changes in allowable revenue, pass-through costs etc.

The only material change relates to the Non-Maui transmission system. First Gas has taken the opportunity to rebalance the non-Maui gas transmission services pricing so it best aligns with the pricing structure intended for the GTAC. The pricing structure changes will result in some delivery points having greater price reductions than others. The changes consider transmission distances and the use of transmission assets for transmission services. These factors were not incorporated into the pricing structure for the prior year ending 30 September 2017.

Consolidation into a single disclosure document

For 2017/18, we have decided to describe the two pricing methodologies in a single document. This reflects that the regulatory control under the new Default Price-Quality Path (DPP) applies to our gas transmission business as a whole (i.e. the Maui and non-Maui system), and we are required to demonstrate that our pricing going forward from 1 October 2017 complies with the combined revenue cap.

Move to a single code and single pricing methodology

First Gas intends to establish a new pricing methodology for our gas transmission business for the year beginning 1 October 2018, once the GTAC has been approved. This new pricing methodology will reflect the new access products established for shippers under the GTAC.

Appendix 1: Maui pipeline pricing methodology

Pricing Methodology for Maui Gas Transmission Services

Effective from 1 October 2017

Pursuant to Gas Transmission Information Disclosure Determination 2012

First Gas Limited
4 September 2017

1 Summary

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

1.1 Existing pricing methodology will continue until 30 September 2018

Section 19.9 of the MPOC requires First Gas to use the methodology set out in Schedule 10 of the MPOC for setting prices for the Maui transmission system while the MPOC is in effect.

> "*19.9 TSP may review and/or change Tariff 1 and/or Tariff 2 in accordance with the tariff principles set out in Schedule 10*…"

Schedule 10 of the MPOC is quoted in **Appendix 2**.

1.2 New Gas Default Price-quality Path (DPP)

From 1 October 2017, First Gas will be on a different DPP from what it was on for the year ending 30 September 2017. The new DPP has decreased revenue on First Gas' transmission business relative to the revenue that would be earned by charging current prices by approximately 10%.

The new DPP uses a different compliance methodology than the current DPP:

- The new DPP uses forecasted quantities for the upcoming year when determining compliance against its revenue cap; while
- The current DPP uses quantities from two years previous.

This change means First Gas can better adjust its prices to meet future changes in quantities. However, this also means First Gas loses the advantage of being able to gain two years of revenue from new demand before that demand falls under the revenue cap.

1.3 This pricing methodology complies with regulatory requirements

First Gas' revenue from gas transmission services is subject to and complies with the new DPP for 2017 - 2022.

This pricing methodology also meets the regulatory requirements listed in the Gas Information Disclosure Determination, as set out in section 6 of this document.

1.4 Transmission prices for 2017/18 have not changed

The transmission prices charged under the MPOC that will apply in the year commencing 1 October 2017 are the same as the prices that applied for 2016/17. Maintaining Maui pipeline prices at current rates complies with the DPP.

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2 Overview

2.1 Background

The Maui pipeline runs 299 km from the Oaonui Production Station (south of New Plymouth) to the Huntly Power Station (south of Auckland) in the North Island of New Zealand.

Beginning transmission in 1979, the Maui Pipeline carried 18 PJ of gas from the Maui field in its first year of operation. In 2015, the Maui Pipeline carried 143 PJ of gas from seven production stations that are directly connected. More than half of that gas goes to three consumer connections to the pipeline: the Huntly Power Station and the two methanol plants owned by Methanex.

First Gas also owns other gas transmission pipelines that are directly connected to the Maui Pipeline at 13 interconnection points.

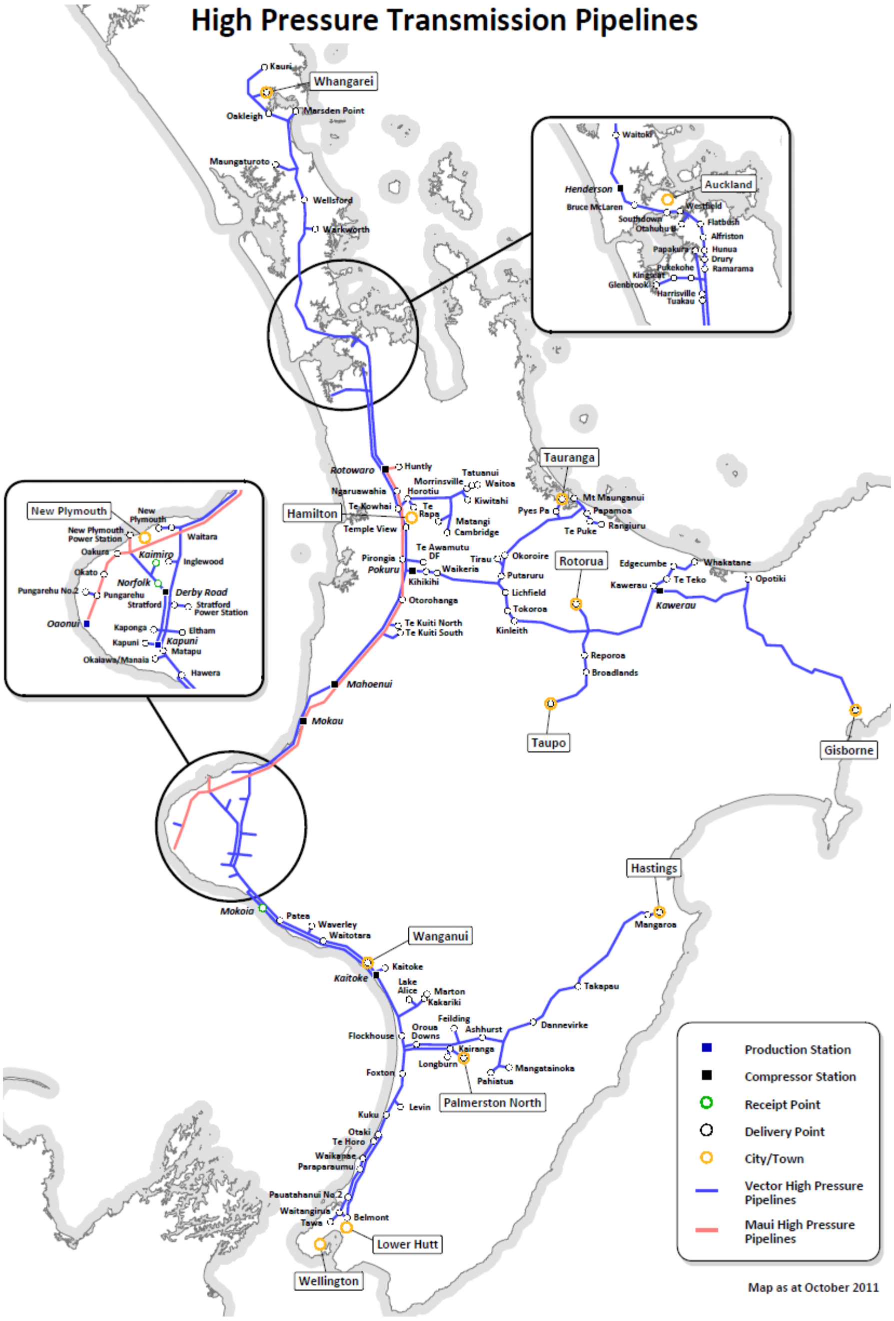
The Maui Pipeline operates under an 'Open Access' regime. This means that any party wishing to carry gas on the Maui Pipeline or wishing to connect to it may do so on standard terms and conditions set out in the Maui Pipeline Operating Code. There are currently 12 different parties who ship gas through the Maui Pipeline.

The map below shows both the transmission system purchased from Vector (in blue) and the ex-Maui Development Limited (MDL) pipeline (in brown).

From 1 October 2017, the gas transmission system will be subject to regulation under the new DPP.

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

Figure 1 First Gas' gas transmission system



2.2 Applicable regulations

This disclosure is prepared in accordance with clause 2.4 of the ID 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 DPP for 2017 - 2022.

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

2.3 Additional disclosures

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

First Gas' Board of Directors has not made any decision to amend the transmission pricing structure beyond the 2017/18 pricing year or approved any Pricing Strategy.

2.4 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 access code (GTAC) covering that entire gas transmission network. Considering the work that this will involve, the new gas transmission access 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. The GTPM is codified in the MPOC and is fit for purpose under the VTC. However, the GTPM does not cover pricing for the former ex-Vector transmission pipelines 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.

This GTPM will apply for 2017/18 and 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.

3 Tariffs and cost components

3.1 Tariffs to recover different cost components

The tariff principles set out in Schedule 10 of the MPOC mean that:

- **Tariff 1** is the price component intended to provide for a return on our asset base and investments, while
- **Tariff 2** is the price component intended to cover our operational costs.

4 Methodology for setting tariffs

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

4.1 Tariff setting approach

We use a two-step approach to setting tariffs for our pricing year.

1. Tariffs are determined following the methodology stipulated in Schedule 10 of the MPOC, as was used in recent years; and
2. Adjustments (if necessary) are made to Tariff 1 and Tariff 2 until the resulting Target Revenue is less than the Forecast Allowable Revenue.

4.2 Tariff calculation

The first step detailed in in Figure 2 determines what the prices would be if the MPOC was treated in isolation, while utilising the Maui pipeline relevant costs used for the DPP.

Figure 2 shows that the expected revenue from prices will be below the Ideal Target Revenue for 2017/18. First Gas intends to recover the difference via prices charged under the VTC. This allows MPOC prices to remain at current levels while First Gas still recovers its combined Target Revenue for the MPOC and VTC.

For the purposes of setting a Target Revenue the Total forecasted Transmission Revenue indicated above will be the 2017/18 Target Revenue.

Figure 2 Determining revenue for standard prices

	$ million per pricing period
Tariff 1	
Pipeline asset value (A)	284.527
WACC (post-tax) (B)	6.41%
Revaluation adjustment (C)	-3.743
Required return (D) = (A) x (B) + (C)	14.495
Depreciation (E)	8.010
Taxation adjustment (F)	4.063
Tariff 1 Ideal Target Revenue (G) = (D) + (E) + (F)	26.568
Throughput forecast (TJ.km) (H)	16,394,056
Tariff 1 ($ / GJ.km) (I)	0.001578
Tariff 1 Revenue (J) = (H) x (I)	25.870
Tariff 2	
Operational expenditure forecast (K)	12.902
Tariff 2 Ideal Target Revenue (L) = (K)	12.902
Throughput Forecast (TJ) (M)	144,333
Tariff 2 ($ / GJ) (N)	0.072061
Tariff 2 Revenue (O) = (M) x (N)	10,401
Total Ideal Target Revenue (P) = (J) + (L)	39.470
Additional transmission revenue via cash-outs (Q)	0.386
Total forecasted Transmission Revenue	**36.657**

The forecasted quantities shown in Figure 2 are the forecasted 2017/18 quantities for those tariffs. The forecast involved the following:

- Huntly Power Station quantities were set equal to the July 2016 to June 2017 quantities as these are approximately equal to the average annual quantities for the previous seven years;
- Methanex quantities were adjusted to allow for the removal of Ngatimaru Road (Receipt) to Ngatimaru Road (Delivery) quantities. Those quantities have been charged for due to a legacy arrangement despite not involving First Gas assets. First Gas has agreed with Methanex to discontinue that arrangement. Methanex will continue to take the bulk of their supply via First Gas assets; and
- Quantities relating to connections with the non-Maui transmission system have been forecasted to change in line with growth trends and known step changes in demand (e.g. Marsden Point’s increased offtake with the commissioning of the Henderson Compressor).

- All other quantities are immaterial and have been held equal to the July 2016 to June 2017 quantities.

4.3 Target Revenue and the DPP

4.3.1 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 has set its prices to recover an amount no greater than the Forecast Allowable Revenue (FAR) under the new DPP. Compliance with the FAR requirement is determined by ensuring the 2017/18 prices multiplied by the forecasted 2017/18 quantities (the Target Revenue) is less than or equal to the FAR. Forecast Revenue is the Target Revenue for the 2017/18 pricing year and its compliance with the FAR is set out in Figure 3.

Figure 3 Determining Target Revenue

Forecast Notional Allowable Revenue	38,637,000
Pass-through and recoverable costs	1,034,659
Forecast Allowable Revenue	39,671,659
Forecast Revenue/Target Revenue	36,656,648
Compliance (Forecast Revenue ≤ FAR)	**Compliant**

5 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****;*

5.1 Consistency with Pricing Principles

The Commerce Commission has determined pricing principles for regulated gas pipeline businesses. First Gas is required to comply with those pricing principles.

As part of our disclosure, we are required to “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”. Our views on the consistency between First Gas’ GTPM and the pricing principles are set out below in Figure 4.

Figure 4 GTPM consistency with pricing principles

Pricing principles	Pricing methodology consistency
(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; (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.	The GTPM is not consistent with this principle: • Incremental and standalone costs have not been considered. • Economic costs of service provision have not been considered. • Available capacity has not been considered. • The effect of additional usage on future investment costs has not been considered.
(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.	The GTPM is the same for all our consumers and does not consider demand responsiveness.

Pricing principles	Pricing methodology consistency
(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.	The GTPM does not satisfy principle (1). Uneconomic bypass is not possible in most cases. Where bypass or alternative fuels are an economic option, the customer cannot apply for non-standard prices under the terms of the MPOC.
(4) Development of prices is transparent, promotes price stability and certainty for consumers, and changes to prices have regard to the effect on consumers.	The GTPM promotes price stability and certainty for our consumers in the short to medium term. In setting prices for this year, First Gas has reflected the value of maintaining current prices under the MPOC – rather than increasing gas transmission prices on the Maui pipeline at the same time as prices are falling across the rest of the transmission system (via prices charged under the VTC).

Inconsistencies between the GTPM and the Commerce Commission's pricing principles is due to the pricing methodology being prescribed by the MPOC and revenue being constrained by both the MPOC and DPP.

The MPOC is a set of terms and conditions that was extensively negotiated among all gas industry participants before the start of the open access regime on the Maui pipeline. Any changes to the MPOC, including its pricing methodology, would require prior industry consultation and a positive recommendation from the Gas Industry Company (GIC).

First Gas has not sought the views of other parties when preparing this pricing methodology. This is because prices charged under the MPOC are defined by principles set out in that code, and First Gas proposes to adopt a new GTPM from 1 October 2018.

6 Compliance matrix

Figure 5 is included to demonstrate how this disclosure complies with the Determination.

Figure 5 GTPM consistency with Determination

Determination requirement	Description
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;	4
(2) Describes any changes in **prices** and **target revenues**;	4
(3) Explains, in accordance with clause 2.4.5 of this section, the approach taken with respect to pricing in **non-standard contracts**; and	Not applicable as non-standard contracts do not exist for the MPOC.
(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 0
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.	Not applicable.
2.4.3 Every disclosure under clause 2.4.1 of this section must-	See individual clauses below.

Determination requirement	Description
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**;	4
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 0
2.4.3(3) State the **target revenue** expected to be collected for the **pricing year** to which the pricing methodology applies;	Section 4.3.1
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 4.2
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;	Not applicable as prices are not changing.
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 4.2
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 disclosed** under clause 2.4.18.	Section 4.2

Determination requirement	Description
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.	Not applicable as no pricing strategy exists for the Maui pipeline other than the move to a new GTPM under the GTAC.

Determination requirement	Description
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- (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**; (b) how the **GTB** determines whether to use a **non-standard contract**, including any criteria used; (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**; (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**.	Not applicable as non-standard prices do not exist for the MPOC.

Appendix 1 Glossary

Act:	the Commerce Act 1986.
Connection Point (CP):	an aggregation of one or more Delivery Points (DPs) for cost allocation purposes.
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.
DPP:	the current DPP is the Gas Transmission Services Default Price-Quality Path Determination 2013, NZCC, 28 February 2013. The new DPP is the Gas Transmission Services Default Price-Quality Path Determination 2017, NZCC14, 29 May 2017.
GJ:	Gigajoule, a unit of energy.
GTB:	the gas transmission business, meaning Maui Development Limited prior to 15 June 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.
MPOC:	the Maui Pipeline Operating Code.
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 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.

VTC: Vector Transmission Code.

Appendix 2 MPOC Schedule 10

SCHEDULE 10 TARIFF PRINCIPLES

TSP will set the Transmission Charges in accordance with the standard practice adopted by utilities businesses in New Zealand. Accordingly, TSP will recover the cost and return of capital as follows. TSP will:

(a) calculate the Maui Pipeline's Optimised Deprival Value or Optimised Depreciated Replacement Cost and multiply this value by a nominal WACC, and then subtract any revaluation gains/losses on the asset ("Required Return");
(b) calculate the return of capital based on the useful life of the asset Depreciation");
(c) aggregate the Required Return and Depreciation to derive the "Required Revenue";
(d) derive a GJ.km tariff ("Tariff 1"); and
(e) apply Tariff 1 across the Maui Pipeline Shippers on the basis of quantity of Gigajoules of Gas transported multiplied by the distance of Gigajoules of Gas transported.

In any given year, in the event that TSP's total revenues are more or less than its required revenue then Tariff 1 may be adjusted for the following years in a manner that endeavours to reduce pricing volatility for Shippers.

The approach adopted by TSP to recover operating expenditure is to:

(a) aggregate the Maui Pipeline's operating costs ("Operational Expenditure");
(b) allocate Operational Expenditure across every Gigajoule of Gas delivered from the Maui Pipeline.

In any given year, in the event that TSP's total Operational Expenditure recovery is more or less than its required recovery then Tariff 2 may be adjusted for the following years in a manner that endeavours to reduce pricing volatility for Shippers.

Appendix 2: Non-Maui pipeline pricing methodology

Pricing Methodology for Non-Maui Gas Transmission Services

Effective from 1 October 2017

Pursuant to Gas Transmission Information Disclosure Determination 2012

First Gas Limited
4 September 2017

1 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 (MDL).

1.1 First Gas developing a new gas transmission code and pricing methodology

First Gas is currently developing a new gas transmission code (the Gas Transmission Access Code, GTAC) that will apply across both the ex-Vector and ex-MDL transmission systems. The GTAC is being developed in consultation with the Gas Industry Company (GIC), shippers, gas producers, major gas users and other stakeholders. The GTAC will replace both the Vector Transmission Code (VTC) and the Maui Pipeline Operating Code (MPOC), and will require a new gas transmission pricing methodology (GTPM). First Gas is aiming for the GTAC and new pricing methodology to take effect from 1 October 2018.

1.2 Existing pricing methodology continue until 30 September 2018

Based on the time required to develop the GTAC and accompanying pricing methodology, First Gas will continue to apply the current GTPM for non-Maui gas transmission assets for the 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 to price the access products under the VTC.

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.

1.3 New Gas Default Price-quality Path (DPP)

From 1 October 2017, a new DPP will apply to First Gas' transmission business. The new DPP decreases the overall revenue that First Gas can earn from its transmission assets (relative to rolling over prices applying under the previous DPP) by around 10%.

The new DPP also uses a different compliance methodology, as a result of changes made to the Input Methodologies applying to gas transmission businesses in 2016. The new DPP uses forecasted quantities for the upcoming year to assess compliance against the revenue cap, rather than using quantities from two years ago. This change allows First Gas to better adjust its prices to reflect known changes in quantities.

1.4 This pricing methodology complies with regulatory requirements

First Gas' revenue from gas transmission services is subject to and complies with the new DPP.

This pricing methodology also meets the requirements of the Gas Information Disclosure Determination.

1.5 Transmission prices for 2017/18 have materially changed

The transmission prices that will apply in the year commencing 1 October 2017 are materially different from the prices that apply for 2016/17. All standard fees, and any fees in non-standard contracts linked to standard fees, have been reduced. This reduction ensures that our prices comply with the DPP.

This results in weighted average prices for non-Maui gas transmission services for 2017/18 being approximately 8.2% lower than the prices that applied in 2016/17.

This average price reduction is not evenly spread across the transmission network, with some delivery points having greater price reductions than others. First Gas has taken the opportunity to rebalance non-Maui gas transmission prices to better reflect the cost of service provision and to more closely align with the pricing structure intended for the GTAC. We consider that the prices applied under this GTPM better account for transmission distances and the use of transmission assets.

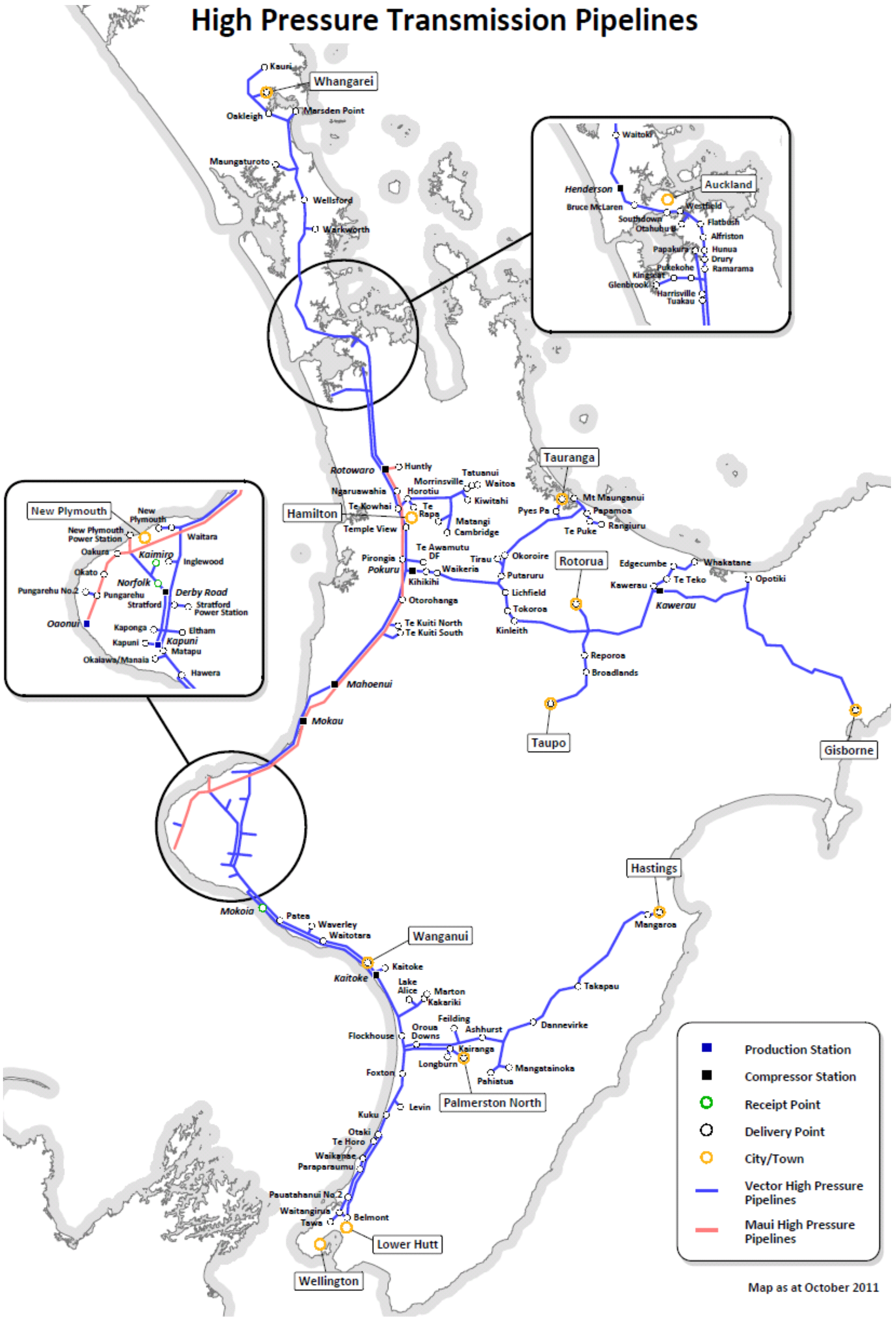
Table of Contents

2 Overview

2.1 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. Figure 1 shows both the transmission system purchased from Vector (in blue) and the ex-Maui Development Limited (MDL) pipeline (in brown).

Figure 1: First 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 eight Shippers. Seven of those Shippers operate as gas retailers, though some also ship gas to their own gas consuming facilities. The other Shipper has yet to engage transmission services or gas retailing.

From 1 October 2017, the gas transmission system will be subject to regulation under the new DPP. In addition to complying with the DPP, the Information Disclosure Determination (the Determination) requires First Gas 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 an evolution of the outcome of that process.

2.2 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 DPP.

The Pricing Principles are defined in the Input Methodologies.

2.3 Additional disclosures

Gas transmission prices are subject to annual approval by the GTB's Board of Directors, and are set to comply with the DPP. 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 2017/18 pricing year or approved any Pricing Strategy.

2.4 Price setting policy framework

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.

2.4.1 Most costs to be recovered are shared costs

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 that prices are developed consistent with the aggregated cost allocations.

2.4.2 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 can 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.

2.5 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

December 2011 GTPM Framework	The December 2011 Framework paper communicated the context and objectives of the review together with an outline of the indicative process.
May 2012 GTPM Position Paper – Proposed Framework and Provisional Prices for PY2013	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 DPP. Vector applied this framework to determine provisional price changes for 2013 which involved an adjustment to the balance between fixed and variable Price Components.
August 2012 GTPM – Summary and Response to Submissions	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 considered 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 and variable revenue split from approximately 60%:40% to 65%:35%.

March 2013 GTPM Cost Allocation Framework and Pricing Methodology	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.
May 2013 GTPM Summary of Submissions, Provisional prices PY2014	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.
May 2014	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.
May 2015	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.
May 2016	In May 2016, First Gas notified provisional prices for the 2016/17 year. The provisional prices incorporated uniform increases to CRFs, and a decrease to the throughput fee on the Frankley Road pipeline. For consistency in the pricing of transmission services, the Kapuni Lactose delivery point was moved from a CRF based price to the Frankley Road pipeline throughput fee. Shippers provided no feedback on the provisional prices. On 31 August 2016, First Gas notified final prices for the 2016/17 year. These prices became effective from 1 October 2016.

2.6 Development of a new transmission code and pricing methodology

Having 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. Given the work that this involves, the new gas transmission access 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 transmission network from Vector, and it is clearly fit for purpose under the VTC. However, the GTPM does not cover pricing for the Maui pipeline and will not 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 implementation of a new gas transmission access code.

The current GTPM will therefore continue to apply for the upcoming regulatory and pricing year (1 October 2017 to 30 September 2018). First Gas also considers that the GTPM should continue to apply until the service and pricing-related elements of the new gas transmission code are agreed with Shippers and other stakeholders.

3 Commercial price-setting framework

3.1 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 many 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; and
- 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 and increases the commercial resilience of gas transmission.

3.2 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.

Figure3: 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 6.

4 Methodology for standard prices

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

Under this GTPM, prices are set for Pricing Regions, which are an aggregation of Connection Points.[1] Section 4.1 provides the rationale for the use of Connection Points and Pricing Regions, and lists the Pricing Regions and Connection Points comprising multiple DPs.

Section 4.2 describes the price setting for the Pricing Regions.

4.1 Pricing Regions

DPs in the same or close geographical location are linked to a single "Connection Point" on the transmission system. For example, 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 that are adjacent (or nearly adjacent) do not have different prices simply because of an artefact of how the cost allocation methodology and pricing methodology work.

Figure 4 below lists all Connection Points which have multiple DPs linked to them. The remaining CPs have only a single DP linked to them.

All stakeholders who submitted on Vector's March 2013 proposals supported greater levels of aggregation for pricing. Consequently, Vector adopted a broader aggregation into the Pricing Regions shown in Figure 5. First Gas has maintained this approach for the 2017/18 pricing year, but has made some changes (shown in Figure 6) to account for distances gas is transmitted and to better align the current pricing with the intended GTPM for the GTAC. This means that DPs in a similar geographic area do not have different prices simply because of an artefact of how the cost allocation methodology and pricing methodology work.

[1] Connection point is a group of delivery points feeding the same network and/or delivery points located at the same gate station

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, Papamoa 2
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

Figure 6: Aggregation of Delivery Points into Pricing Regions

2017/18 Pricing Region	Current Pricing Region(s)	Delivery points
1 Taranaki	Taranaki	Eltham, Inglewood, Kaponga, New Plymouth, Stratford, Waitara, Oakura, Okato, Opunake, Pungarehu No 1, Pungarehu No 2, Pokuru 2 Delivery, Stratford 2 (Peaker), Stratford 3 (Storage), TCC Power Station
2 Waikato South	Waikato south	Otorohanga, Pirongia, Te Awamutu DF, Te Kuiti North, Te Kuiti South,
3 Auckland	Auckland	Alfriston, Drury 1, Flat Bush, Glenbrook (Steel Mill), Greater Auckland, Harrisville, Hunua, Hunua (Nova), Hunua 3, Kingseat, Pukekohe, Ramarama, Tuakau 2, Waitoki
4 Northland	Northland	Marsden 1 (NZRC), Marsden 2, Kauri DF, Maungaturoto DF, Warkworth, Wellsford, Whangarei
5 Waikato North	Waikato north	Cambridge, Horotiu, Huntly Town, Kiwitahi 1 (Peroxide), Kiwitahi 2, Matangi, Morrinsville, Morrinsville DF, Ngaruawahia, Tatuanui DF, Te Rapa Cogen Plant, Waitoa
6 South Taranaki - Whanganui	Manawatu-Wanganui	Hawera, Hawera (Nova), Kaitoke, Kakariki, Lake Alice, Okaiawa \ Manaia, Marton, Matapu, Mokoia, Patea, Waitotara, Wanganui, Waverley
7 Manawatu - Horowhenua	Hawkes Bay and Wellington	Ashhurst, Feilding, Flockhouse, Kairanga, Longburn, Mangatainoka, Oroua Downs, Pahiatua, Pahiatua DF, Palmerston North, Foxton, Kuku, Levin,
8 Hawkes Bay	Hawkes Bay	Dannevirke, Hastings, Hastings (Nova), Mangaroa, Takapau
9 Wellington	Wellington	Belmont, Greater Waitangirua, Otaki, Paraparaumu, Pauatahanui 2, Tawa A, Tawa B (Nova), Te Horo, Waikanae 2
10 Waikato East	Waikato south	Kihikihi, Kinleith, Kinleith (Paper mill), Lichfield DF, Lichfield 2, Okoroire Springs, Putaruru, Tirau, Tirau DF, Tokoroa, Waikeria
11 Bay of Plenty West	Western Bay of Plenty	Greater Mt Maunganui, Greater Tauranga, Rangiuru, Te Puke
12 Bay of Plenty South	Eastern Bay of Plenty	Broadlands, Kawerau, Kawerau (ex-Caxton), Kawerau (ex-Tasman), Reporoa, Rotorua, Taupo,
13 Bay of Plenty East	Eastern Bay of Plenty	Edgecumbe, Edgecumbe DF, Te Teko, Whakatane
14 Eastland	Eastern Bay of Plenty	Gisborne, Opotiki
Hamilton	Hamilton	Greater Hamilton, Temple View, Te Kowhai

4.2 Price setting

Within the GTPM, revenue and prices are determined for non-standard contracts first so standard prices can be set. This is due to non-standard prices largely being ongoing and/or negotiated on an individual basis.

4.2.1 Non-standard contracts and standard price setting

Before standard prices can be determined, the 2017/18 prices and revenue for non-standard contracts is determined. The prices for these contracts are a combination of ongoing contracts on a set price path and contracts that are renewed on an annual basis. Contracts that are to be renewed have had their 2017/18 prices set at the same rates as 2016/17.

Figure 7: Determining revenue for standard prices

Forecast Allowable Revenue	89,646,664
Revenue from Non-standard contracts	31,420,834
Revenue for determining standard prices	58,225,830

2017/18 forecasted quantities each non-standard contract is either:

- The average annual quantities over the last seven years; or
- The average for the last years that best match current operating conditions for the relevant end user; or
- The estimated quantities for 2017/18 based on known step changes in quantities (i.e. historical quantities cannot be used to determine future quantities).

4.2.2 Standard price setting

Standard prices for each Pricing Region are assessed on a case by case basis while complying with the overall Forecast Allowable Revenue by being less than or equal to revenue applicable to standard prices determined in Figure 8.

The prices set for 2017/18 are a transition toward the GTAC GTPM. Development of the GTAC GTPM will assess the revenue earned from transmission services for each of the Pricing Regions from the VTC and the MPOC.

Assessment of prices for each Price Region is based on the commonality of transmission assets used and the relative use of transmission assets by other Pricing Regions. Figure 9 shows how those price changes effected the revenue from each Price Region.

Figure 8: Standard price revenue changes

2017/18 Pricing Region	Standard Price Revenue		Change	Comment
	P2018*Q2018	P2017*Q2018	%	
1 Taranaki	$478,198	$674,656	-29.1%	Reduced to equivalent of Frankley Road Pipeline throughput fee
2 Waikato South	$1,334,902	$1,553,616	-14.1%	Reduced by average reduction and made equal to 5 & 10 but maintained higher than 3 due to assets used
3 Auckland	$22,080,048	$24,553,637	-10.1%	Reduced by average reduction but maintained lower than 2, 5 & 10 due to assets used
4 Northland	$400,097	$423,695	-5.6%	Reduce prices but no lower than the minimum revenue required for the return on investment of the Henderson compressor
5 Waikato North	$2,513,597	$2,717,333	-7.5%	Reduced by average reduction and made equal to 2 & 10 but maintained higher than 3 due to assets used
6 South Taranaki - Whanganui	$2,810,777	$3,225,365	-12.9%	Reduced to be approximately equal to the average reduction
7 Manawatu - Horowhenua	$2,613,281	$2,964,590	-11.9%	Reduced to be approximately equal to the average reduction
8 Hawkes Bay	$2,468,531	$2,724,838	-9.4%	Reduced but maintained higher than Pricing Region 7
9 Kapiti - Wellington	$7,996,384	$9,298,976	-14.0%	Reduced to be approximately equal to the average reduction but kept higher than Pricing Region's 7 and 8 due to assets used
10 Waikato East	$6,375,192	$7,420,294	-14.1%	Reduced by average reduction and made equal to 2 & 5 but maintained higher than 3 due to assets used
11 Bay of Plenty West	$1,254,562	$1,438,239	-12.8%	Reduced to be approximately equal to the average reduction
12 Bay of Plenty South	$3,058,888	$3,525,402	-13.2%	Reduced but maintained higher than Pricing Region 11 due to assets used

2017/18 Pricing Region	Standard Price Revenue		Change	Comment
	P2018*Q2018	P2017*Q2018	%	
13 Bay of Plenty East	$2,468,916	$2,727,136	-9.5%	Reduced but maintained higher than Pricing Region 12 due to assets used
14 Eastland	$1,122,130	$1,189,184	-5.6%	Reduced but maintained higher than Pricing Region 13 due to assets used
Hamilton	$1,225,476	$1,240,920	-1.2%	CRF maintained at current rates
Total	$58,200,981	$65,677,882	-11.4%	

2017/18 forecasted standard price quantities use either:

- Growth trends over the previous seven years if the Connection Point is a network not dominated by a single end user; or
- The average over the last seven years if the Connection Point is the majority of demand is for a single end user; or
- Estimated quantity for 2017/18 if historical quantities cannot be used as the basis of forecasting.

4.3 Price setting and the allocation of target revenue

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 has set its prices to recover an amount no greater than the Forecast Allowable Revenue (FAR) under the new DPP. Compliance with the FAR requirement is determined by ensuring the 2017/18 prices multiplied by the forecasted 2017/18 quantities (the Forecast Revenue) is less than or equal to the FAR. Forecast Revenue is the Target Revenue for the 2017/18 pricing year and its compliance with the FAR is set out in Figure 10.

Figure 9: Determining Target Revenue

Forecast Notional Allowable Revenue	82,959,000
Pass-through and recoverable costs	6,687,664
Forecast Allowable Revenue	89,646,664
Forecast Revenue/Target Revenue	89,621,817
Compliance (Forecast Revenue ≤ FAR)	Compliant

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

4.4 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 2017/18 pricing year, First Gas has:

- Reduced the Throughput Fee (TPF) to \$0.05/GJ from \$0.06/GJ which applies across all Pricing Regions;
- Maintained CRF for Greater Hamilton at current rates;
- Decreased other CRFs by between 5 to 30%; and
- Reduced the standard Frankley Road Pipeline transmission fee to \$0.28/GJ.

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

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;*

It is neither appropriate nor possible to publicly disclose the Target Revenue for individual consumers. The cost allocation approach allocates costs to Connection Points and Pricing Regions. Consumers of transmission services may take delivery of gas 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 10.

Figure 10: Target revenue by Pricing Region

2017/18 Pricing Region	Target revenue from prices (P_{i2018},Q_{i2018})[2]
1 Taranaki	$15,040,278
2 Waikato South	$1,334,902
3 Auckland	$22,524,577
4 Northland	$10,329,076
5 Waikato North	$4,139,720
6 South Taranaki - Whanganui	$3,286,939
7 Manawatu - Horowhenua	$3,879,444
8 Hawkes Bay	$2,714,122
9 Kapiti - Wellington	$8,033,905
10 Waikato East	$8,178,678
11 Bay of Plenty West	$1,278,350
12 Bay of Plenty South	$3,058,888
13 Bay of Plenty East	$3,466,330
14 Eastland	$1,122,130
Hamilton	$1,225,476
Target Revenue	**$89,621,817**

[2] Determined by actual forecasted quantities by region times prices

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;

- Capacity Reservation Fee (CRF), applied to the (annual) GH 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 11.

Figure 11: Proportion of target revenue by price component

Price component	Target revenue	Proportion
Capacity Reservation Fees	$53,156,860	59.3%
Other Fixed Fees	$25,794,915	28.8%
Throughput Fees	$4,882,319	5.4%
Over-run Fees	$3,348,027	3.7%
Interruptible Contracts	$2,439,696	2.7%
	$89,621,817	100%

4.5 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 2017, First Gas transmission services revenue cap are set to comply with a new DPP. Weighted average gas transmission prices charged under the VTC required to comply with the DPP are 8.2% lower than those charged in 2016/17.

As noted above, the relative pricing for each Pricing Region has changed in this GTPM.

Figure 12 below shows the price changes by Pricing Region.

Figure 12: Price changes by Pricing Region

Pricing Region	Notional revenue		Revenue change
	P_{i2018},Q_{i2018}	P_{i2017},Q_{i2018}	%
1 Taranaki	$15,040,278	$16,041,032	-6.2%
2 Waikato South	$1,334,902	$1,553,616	-14.1%
3 Auckland	$22,524,577	$24,983,279	-9.8%
4 Northland	$10,329,076	$9,895,883	4.4%
5 Waikato North	$4,139,720	$4,337,563	-4.6%
6 South Taranaki - Whanganui	$3,286,939	$3,631,895	-9.5%
7 Manawatu - Horowhenua	$3,879,444	$4,400,404	-11.8%
8 Hawkes Bay	$2,714,122	$2,812,085	-3.5%
9 Kapiti - Wellington	$8,033,905	$9,335,584	-13.9%
10 Waikato East	$8,178,678	$9,486,268	-13.8%
11 Bay of Plenty West	$1,278,350	$1,475,925	-12.8%
12 Bay of Plenty South	$3,058,888	$3,525,402	-13.2%
13 Bay of Plenty East	$3,466,330	$3,716,936	-6.7%
14 Eastland	$1,122,130	$1,189,184	-5.6%
Hamilton	$1,225,476	$1,240,920	-1.2%
Notional revenue	**$89,621,817**	**$97,625,975**	**-8.2%**

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

The increase in revenue from Pricing Region 4 is due to price increases of ongoing non-standard contracts being greater than the price reductions of standard priced transmission services.

5 Consistency with Pricing Principles

5.1 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****;*

5.2 Consistency with Pricing Principles

The Commerce Commission has determined pricing principles for regulated gas pipeline businesses. First Gas is required to report consistency with those principles in its GTPM. Our evaluation of the consistency between First Gas' GTPM and the pricing principles is set out in Figure 13.

Figure 13: GTPM consistency with pricing principles

Pricing principles	Pricing methodology consistency
(1) Prices are to signal the economic costs of service provision, by- (d) 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; (e) having regard, to the extent practicable, to the level of available service capacity; and (f) signalling, to the extent practicable, the effect of additional usage on future investment costs.	The GTPM is not fully consistent with this principle. Although the GTPM inherited from Vector did consider incremental and standalone costs, First Gas believes that the Pricing Regions used previously do not reflect the commonality of the delivery points within those regions. To address this issue, while avoiding unnecessary price changes, First Gas has adjusted prices to better reflect the differences between Pricing Regions. The ability to signal available capacity and the effect of additional usage on future investment costs is driven as much by the access products offered under the code as the way those products are priced. Access products under the GTAC (particularly the ability to offer priority rights), have been developed to provide better price signals in situations when transmission is scarce.

Pricing principles	Pricing methodology consistency
(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.	The GTPM is not fully consistent with this principle. As with principle 1, the terms of transmission access code have a material impact on consistency with this principle. In the case of the VTC, the ability to offer non-standard pricing in certain circumstances provides the ability to directly gauge alternative energy supply options that are available to consumers and reflect those in prices. Pricing in this GTPM is based on location and the pricing structure inherited under previous versions of this GTPM.
(3) Provided that prices satisfy (1) above, prices are responsive to the requirements and circumstances of consumers in order to- (c) discourage uneconomic bypass; and (d) 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.	Where bypass or alternative fuels are an economic option, the customer can apply for non-standard prices under the VTC.
(4) Development of prices is transparent, promotes price stability and certainty for consumers, and changes to prices have regard to the effect on consumers.	We believe development of our prices is transparent and the GTPM promotes price stability and certainty for our consumers in the short to medium-term.

First Gas has not sought the views of other parties for this pricing methodology, given that we intend for the structure of this methodology to only apply for one more year. We are seeking the views of other parties for the pricing methodology that will apply under the GTAC from 1 October 2017 and will consult on that methodology in 2018.

6 Pricing for non-standard contracts

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

6.1 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 the following non-standard transmission agreements:

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 37 non-standard contracts.[3] Their estimated charges represent 34% of Target Revenue for 2017/18.

6.2 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 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 access code and GTPM.

[3] 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, i.e. where Shippers are charged the throughput fee for that pipeline.

6.3 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 14 below.

Figure 14: 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; 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.	Prices are subsidy-free. 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.	Prices remain subsidy-free. 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.

6.4 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.

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 First Gas 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.

7 Compliance matrix

Figure 15 is included to demonstrate how this disclosure complies with Determination.

Figure 15: GTPM compliance with Determination

Principle	Description
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;	4
(2) Describes any changes in **prices** and **target revenues**;	4
(3) Explains, in accordance with clause 2.4.5 of this section, the approach taken with respect to pricing in **non-standard contracts**; and	1
(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 0
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.	Not applicable.
2.4.3 Every disclosure under clause 2.4.1 of this section must-	See individual clauses below.

Principle	Description
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**;	4
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 0
2.4.3(3) State the **target revenue** expected to be collected for the **pricing year** to which the pricing methodology applies;	Section 4.3.1
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;	Not applicable as prices have been set subjectively so that price shocks in the transition to the GTAC GTPM are minimised.
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 4.5
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 0
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 0

Principle	Description
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 2017/18.

Principle	Description
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**.	

8 Glossary

Act:	the Commerce Act 1986.
Allowable Notional Revenue:	the revenue First Gas can 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 October2012.
DPP:	the current DPP is the Gas Transmission Services Default Price-Quality Path Determination 2013, NZCC, 28 February 2013. The new GDPP is the Gas Transmission Services Default Price-Quality Path Determination 2017, NZCC14, 29 May 2017.
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:	Vector Transmission Code

Appendix 3: Director certificate

Director certificate

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

Clause 2.9.2

We, Philippa Dunphy and 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; and

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.

Philippa Dunphy	Richard Krogh
Director	Director
4 September 2017	4 September 2017
Date	Date

Appendix 2: GY2020 GTAC Transmission Pricing Methodology

Pricing Methodology for Gas Transmission Services

From 1 October 2019

Pursuant to the Gas Transmission Information Disclosure Determination 2012

First Gas Limited
June 2019

Introduction

First Gas operates 2,500 kilometres of gas transmission pipelines (including the Maui pipeline), and more than 4,700 kilometres of gas distribution pipelines across the North Island. These gas infrastructure assets transport gas from Taranaki to major industrial gas users, electricity generators, businesses and homes, and supply around 20 percent of New Zealand's primary energy needs.

For further information on First Gas, please visit our website www.firstgas.co.nz.

Information disclosure

This document is the pricing methodology for gas transmission services prepared pursuant to clause 2.4 of the *Gas Transmission Information Disclosure Determination 2012* (consolidating all amendments as at 3 April 2018), issued by the Commerce Commission on 3 April 2018 (the ID Determination).

This Pricing Methodology covers the 12-month pricing year from 1 October 2019. This is the first Pricing Methodology prepared under the new Gas Transmission Access Code (GTAC).

A signed director certificate is provided with this Pricing Methodology.

This Pricing Methodology was prepared and approved on 28 June 2019.

Further information

For further information regarding this Pricing Methodology, please contact:

Karen Collins
Regulatory Policy Manager
First Gas Limited
Karen.Collins@firstgas.co.nz
04 979 5368

Disclaimer

For presentation purposes, some numbers in this document have been rounded. This may cause small discrepancies or rounding inconsistencies when aggregating some of the information presented in the document. These discrepancies do not affect the overall calculations which are based on more detailed information.

Glossary

Act:	Commerce Act 1986.
Allowable Notional Revenue:	The revenue First Gas is allowed to earn during the pricing year under the Default Price-Quality Path (DPP) Determination.
Connection Point (CP):	An aggregation of one or more Delivery Points (DPs) for cost allocation purposes.
CPI:	Consumer Price Index.
Daily Nominated Capacity (DNC):	In respect of a Day and a Shipper, the quantity of Gas that a Shipper takes in a Delivery Zone, at a Delivery Point in a Delivery Zone or at an Individual Delivery Point.
Delivery Point (DP):	A facility (including any associated land and equipment) at which one or more Shippers take (or may take) Gas from the Transmission System.
Delivery Zone:	Means a group of two or more Delivery Points which, for the purposes of nominations are treated as a single notional delivery point and have a single fee for transmission services.
DPP:	*Gas Transmission Services Default Price-Quality Path Determination* 2017, NZCC14, 29 May 2017.
GJ:	Gigajoule, a unit of energy.
GTAC:	Gas Transmission Access Code.
GTB:	Gas Transmission Business, meaning First Gas Limited.
ID Determination:	*Gas Transmission Information Disclosure Determination 2012*, consolidating all amendments as of 3 April 2018, published by the Commerce Commission
GY2020	Gas year starting 1 October 2019 to 30 September 2020
Input Methodologies:	*Gas Transmission Services Input Methodologies Determination 2012* consolidating all amendments as of 3 April 2018, published by the Commerce Commission.
MPOC:	Maui Pipeline Operating Code.
Operational Balancing Arrangement (OBA):	A Gas allocation option available to an Interconnected Party under its ICA at one or more Receipt Points, or at one or more Individual Delivery Points, whereby at the relevant point: a) Each Shipper's Receipt Quantity or Daily Delivery Quantity is its Approved NQ; and b) Any difference between the Scheduled Quantity and the metered quantity is the responsibility of the OBA Party.

Pass-through costs	As defined in clause 3.1.2(1) of the *Gas Transmission Services Input Methodologies Determination 2012*, pass-through costs include: a) rates on system fixed assets paid or payable by a GTB to a local authority under the Local Government (Rating) Act 2002; and b) levies payable: (i) under regulations made under the Commerce Act; (ii) under regulations made under the Gas Act 1992; or (iii) by all members of the Electricity and Gas Complaints Commissioner Scheme by virtue of their membership; or c) a cost associated with the supply of gas transmission services, outside the control of the gas transmission business, not treated as a recoverable cost, and appropriate to be passed through to consumers
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 2012.
Pricing Zone:	A group of Delivery Points with the same pricing DNC (as set out in section 4.3.2); 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.
Receipt Zone:	Means that part of the Transmission System in which Receipt Points are located.
Recoverable costs	As defined in clause 3.1.3 of the *Gas Transmission Services Input Methodologies Determination 2012*, recoverable costs include 12 different types of costs that a gas transmission business can directly recoup through its prices.
Shipper:	A person named as a shipper in a Transmission Services Agreement with First Gas.
Specified Shipper Nomination:	The automated nominations made by First Gas for Specified Shippers in respect of gas delivered to mass market consumers.
Target revenue:	The revenue the GTB expects to receive during the pricing year, as described in section 4.1 of this document.
TOU:	Time of Use
TPM:	Transmission Pricing Methodology.
VTC	Vector Transmission Code

Background documents

Information about the Gas Transmission Access Code (GTAC) Implementation Project is available on the First Gas website here: https://firstgas.co.nz/about-us/gtac/

All regulatory documents relating to transmission pricing are available on First Gas' website here: https://firstgas.co.nz/about-us/regulatory/transmission/

All prices are set to comply with the revenue path set in the DPP Determination for gas transmission. Further details are set out in the *Ex-ante price-setting compliance statement* for the year commencing 1 October 2019, which is also available on the Regulatory page of the First Gas website.

Table of Contents

1 Overview of First Gas' transmission system

First Gas provides gas transmission services in the North Island of New Zealand, over a network comprising of approximately 2,500 kilometres of pipeline.

1.1 First Gas transmission system

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 **Maui gas transmission pipeline** runs 309 kilometres from the Oaonui Production Station (south of New Plymouth) to the Huntly Power Station (south of Auckland) in the North Island and was purchased by First Gas in June 2016. The Maui pipeline began transmission in 1979 and carried 18 PJ of gas from the Maui field in its first year of operation. For the gas year 2017/18, the Maui Pipeline carried 138 PJ of gas from seven production stations that are directly connected to the pipeline. Nearly half of that gas goes to four consumer connections to the pipeline – the Huntly Power Station and the three methanol plants owned by Methanex.

First Gas also owns other gas transmission pipelines (previously referred to as the **Non-Maui gas transmission pipeline**) that are directly connected to the Maui pipeline at 13 interconnection points. This system was largely built between 1968 and the mid-1980s by the Natural Gas Corporation. It was purchased by Vector in 2005, and subsequently by First Gas in April 2016. Gas is taken from this transmission system and delivered to 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.

1.2 Industry context for gas transmission pricing

The shared use of a significant portion of assets has significant implications for the development of transmission prices. Transmission prices largely 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.

First Gas contracts with Shippers and transports gas from sources of supply through the transmission system for these Shippers. At present, there are eight Shippers. Seven of these Shippers operate as gas retailers, although some also ship gas to their own gas-consuming facilities. Any party can become a Shipper by entering into a Transmission Services Agreement (TSA).

Shippers can repackage the transmission charges they pay, meaning that price signals do not necessarily reach the consumer. Gas transmission costs also represent a small portion of the average consumer's gas bill, so any price signal at the transmission level tends to be overwhelmed by wholesale gas costs, distribution charges and retail costs.

1.3 Regulatory environment for gas transmission

As the sole provider of gas transmission infrastructure, First Gas is regulated by the Commerce Commission under Part 4 of the Commerce Act 1986. We are subject to:

- *Price-quality path regulation*, which sets the prices we can charge and the level of service we must provide our customers; and
- *Information disclosure requirements*, which requires us to publish information about our financial and non-financial performance.

From 1 October 2017 to 30 September 2022, the gas transmission system is subject to the revenue cap specified in the *Gas Transmission Services Default Price-Quality Path Determination 2017* (DPP Determination). The allowable revenue that First Gas can earn from providing gas transmission services is primarily derived from the value of regulated transmission assets and the allowable rate of return set by the Commerce Commission. Inputs to setting the DPP need apply the Input Methodologies (IMs) that were developed by the Commerce Commission in 2010 and amended in 2016.

The *Gas Transmission Information Disclosure Determination 2012* (ID Determination) sets out a number of requirements around transmission pricing, including that we publish a transmission pricing methodology and explain whether our prices comply with the Commission's pricing principles. The requirements are specified in clause 2.4 of the ID Determination, and our compliance with these requirements is summarised in **Appendices 1 and 2** of this TPM.

1.4 Development of a single access code and new pricing methodology

Having taking ownership of all open-access gas transmission pipelines in 2016, a key priority for First Gas was to develop a single new gas transmission access code (GTAC) covering the entire gas transmission network. The GTAC creates a common set of terms and conditions for pipeline users across our network. It creates a single, flexible set of arrangements where shippers can nominate for daily gas deliveries to 16 delivery zones. This removes the current point to point nominations on the Maui system and annual capacity reservations on the non-Maui system (under the Vector Transmission Code or VTC). The GTAC arrangements are flexible and simplified, reducing costs to Shippers and consumers.

We see this gas transmission pricing methodology (TPM) as being inseparable from the prevailing gas transmission access code. First Gas inherited the previous TPMs[1] when we purchased the transmission businesses from Vector and Maui Development Limited. These TPMs were fit for purpose under the Vector Transmission Code (VTC) and Maui Pipeline Operating Code (MPOC) that respectively applied to the two transmission systems. However, these TPMs only cover pricing for separate parts of the network and were not appropriate for the new code that offers new access products across the entire gas transmission network.

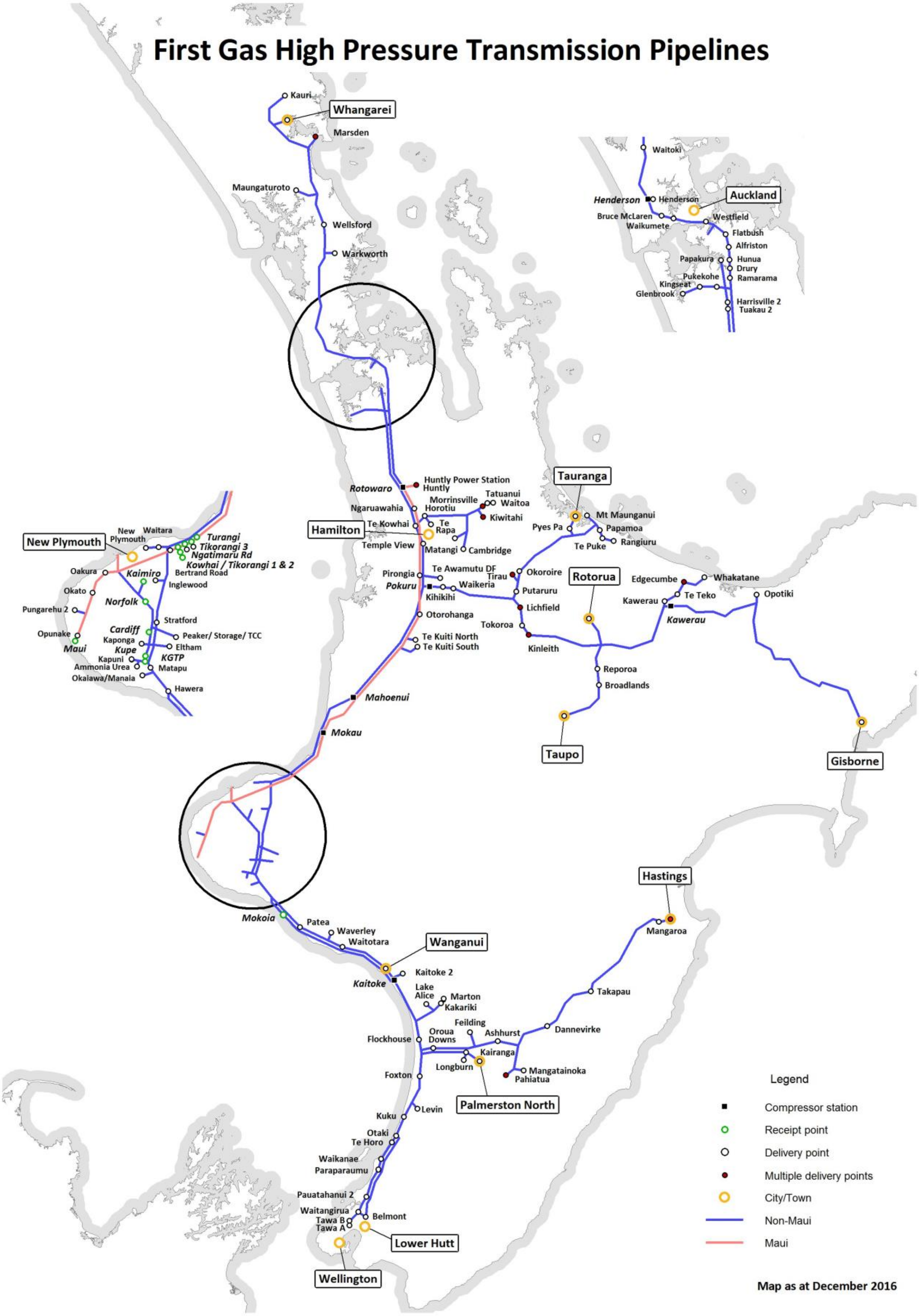
The development of this TPM is therefore occurring in step with the implementation of the new gas transmission access code and will see one, unified TPM also covering all the high-pressure gas transmission pipelines in the North Island.

The main change from last year's pricing methodologies is to set prices for the GTAC access products – primarily Daily Nominated Capacity (DNC) fees, which are payable by Shippers for transmission capacity provided under a TSA for transmission to a Delivery Zone or at an Individual Delivery Point. DNC is requested daily through a nominations process, which provides the flexibility for Shippers to book capacity based on changing requirements and reduces the risk of unused capacity. Changes to incentives for balancing have also been introduced.

The basis of this TPM has been to identify what revenue is currently earned from each Delivery Zone and dedicated delivery point, and to convert this revenue into a DNC fee for the corresponding Delivery Zone or Dedicated Delivery Point. This ensures that while the access products offered under the GTAC differ, a consistent amount of revenue will be collected from each location on the network on an annual basis. This approach was tested during the GTAC development process and stakeholders did not raise significant concerns or proposed alternative methodologies for navigating this change.

[1] https://firstgas.co.nz/wp-content/uploads/First-Gas-GTB-pricing-methodology-PY2019.pdf

Figure 1: Network map



2 Overview of requirements

This section sets out the regulatory requirements that apply to pricing methodologies for gas transmission services.

2.1 Compliance with revenue cap for GTB

First Gas' transmission business is required to set our prices to recover an amount no greater than the Forecast Allowable Revenue (FAR) under the current DPP (2017 – 2022). Compliance with the FAR requirement is determined by ensuring the 2019/20 prices multiplied by the forecast 2019/20 quantities (the Target Revenue) is less than or equal to the FAR.

Target Revenue for the 2019/20 pricing year and our compliance with the FAR is set out in Table 1 below. First Gas is compliant with its DPP revenue cap.

Table 1: Determining Target Revenue and compliance with DPP

	Amount
Forecast Net Allowable Revenue	$126,456,000
Pass-through and recoverable costs	$4,239,275[2]
Forecast Allowable Revenue	**$130,695,275**
Target Revenue	**$130,692,026**
Compliance (Target Revenue ≤ FAR)	**Compliant**

Further detail on our compliance with the revenue cap can be found in our *Ex-ante price setting Compliance Statement* on our website.[3]

2.2 Regulatory requirements for a pricing methodology disclosure

This pricing methodology is prepared in accordance with clause 2.4 of the ID Determination. Our compliance with these requirements is summarised in the compliance table provided in **Appendix 1**.

First Gas is also required to demonstrate the extent to which the pricing methodology is consistent with the pricing principles, as defined in the applicable Input Methodologies.[4] In considering how prices should be set, we have applied those principles in the following way:

- Pricing for zones and delivery points should reflect usage of the system and future expansion costs. Deliveries to points further out in the system should pay more and users should pay more in locations that are congested to provide signals of the value of scarce capacity; and
- Pricing at the zone and delivery point level should be consistent with existing prices under the VTC and MPOC to ensure that there are time-consistent incentives for gas usage in a particular region and that any tariff shock is minimised.

Further detail on our approach to aligning prices with the Pricing Principles is provided in **Appendix 2**.

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[2] Incorporates the opening balance of revenue wash-up account, see 4.6.5.

[3] https://firstgas.co.nz/about-us/regulatory/transmission/

[4] *Gas transmission services input methodologies determination 2012*, consolidating all amendments as of 3 April 2018, Commerce Commission.

3 GTAC pricing structure

Pricing under the GTAC represents a significant change from pricing under both the MPOC and VTC. The aim of these changes has been to enable the use of gas by:

- Allow flexibility for Shippers to book capacity as they require and reduce the potential for unused capacity reservations;
- Provide appropriate incentives for users to balance pipeline receipts and deliveries; and
- Ensure that risks associated with pricing are allocated to those best able to manage those risks.

The following sections outline the structure of pricing under the GTAC. These sections are not a substitute for the code but provide a guide to assist in understanding of this TPM.

3.1 Transmission charges

Transmission charges are charges relating to the provision of transmission capacity on the pipeline. These prices are charged to Shippers based on their deliveries of gas to their customers at delivery points. Overruns and underruns may be charged to parties with Operational Balancing Arrangements (OBA Parties), as they have control of the flows at the delivery point. Being an OBA party is a choice for the interconnected party using a delivery point.

3.1.1 Daily Nominated Capacity (DNC)

Shippers will make nominations for how much capacity they require on each day to deliver gas to their customers at any delivery point or zone. How we calculate the DNC fee is the subject of this TPM. The amount we charge Shippers is the DNC fee multiplied by the amount of gas transported. Section 11.1 of the GTAC sets out this charging.

3.1.2 Priority rights (PRs) charges and congestion management charges

If there is likely to be congestion at a delivery point(s), First Gas may contract for interruptible capacity or issue priority rights at the affected delivery point(s). The process for obtaining and using interruptible capacity is set out is sections 3.5-3.12 of the GTAC, and the process of auctioning PRs to shippers is set out in sections 3.17-3.24 of the GTAC. Shippers holding priority rights will have priority for allocation of capacity at that delivery point during the congestion period.

Sections 11.2 and 11.3 of the GTAC set out the process of charging for PRs. In effect, priority rights fees charged during a year are returned to Shippers in that year and therefore do not contribute towards Target Revenue or otherwise affect transmission pricing. In a similar way, the process of recovering the costs of interruptible capacity is set out in section 11.12 of the GTAC and is revenue-neutral in terms of its effect on First Gas.

3.1.3 Overrun/Underrun charges

If Shippers deliver more or less gas to their customers than their nominated DNC those gas flows are subject to an underrun/overrun charge as specified in section 11.4 of the GTAC. This ensures that shippers are disincentivised to either book too much capacity and prevent other Shippers from delivering gas or book too little capacity to avoid charges.

The charges are as follows:

- **For overruns**: The DNC Fee x the daily overrun quantity x F
- **For underruns**: The DNC Fee x the daily underrun quantity x (F-2)

The factor ‘F’ is set at 1.5 except when the delivery points is congested when it is 7.5. These settings provide an equal incentive to provide an accurate nomination and stronger incentives for accuracy at locations where capacity is scarce.

If the interconnected party chooses an OBA, they will be liable for overrun/underrun charges.

3.1.4 Peaking charges

Some large users, such as peaking power stations, have large variations in intra-day flows that have the potential to affect other pipeline users. These users must provide an hourly flow profile as their nomination. They are subject to peaking charges under section 11.5 of the GTAC instead of overrun/underrun fees.

The charges are as follows:

- **For overruns**: The DNC Fee x the hourly overrun quantity x M
- **For underruns**: The DNC Fee x the hourly underrun quantity x (M-2)

The factor ‘M’ is set at 1.5 except when the delivery points is congested when it is 7.5. These settings provide an equal incentive to provide accurate hourly nominations. To recognise the difficulties of precisely nominating on an hourly basis, these fees are only charged if the flow differs from either the nomination for that hour or the running three-hourly average of nominations by more than 25%.

If the interconnected party chooses an OBA, they will be liable for peaking charges.

For the purposes of the TPM, these fees have not been specifically modelled but rather the revenue considered to be part of the Overrun/Underrun revenue. This approach reflects the fact that the revenue generated from Peaking Charges is intended to be equivalent to revenue that would otherwise arise from Overrun/Underrun charges.

3.1.5 Auto-nomination charges

Shippers delivering gas to mass-market customers have different access to information than Shippers serving larger, more predictable loads. Usage patterns and delays between daily flows and meter data make it difficult to predict these customers’ volumes. Mass-market consumers also account for a relatively small proportion of total transmission capacity used. To appropriately reflect these usage characteristics, First Gas has developed an algorithm to predict the load for category 4 and 6 (mass-market) customers at each delivery zone for each shipper. First Gas consulted on the development of this algorithm in March 2019.

Shippers can choose to use this automated nomination in lieu of making their own nominations. Shippers that choose to use this automated nomination will not be liable for overrun/underrun charges under section 11.4 of the GTAC but are instead subject to Auto-nomination Charges under section 11.7 of the GTAC.

Auto-nomination Charges are set to the average overrun and underrun for all non-mass market load for that month over the entire network multiplied by the DNC Fee for each zone.

Shippers that choose to overwrite the automated nomination are liable for overrun/underrun charges under section 11.2.

3.1.6 Over-flow charges

If too much gas is delivered to a delivery point, this can damage First Gas equipment. Over-flow charges allows First Gas to incentivise flows of gas that match the delivery point capacity. This charge is specified in section 11.8 of the GTAC and is set at the hourly overflow quantity multiplied by the DNC Fee multiplied by 20. If the interconnected party chooses an OBA, they will be liable for over-flow charges.

First Gas has incentives to upgrade delivery point capacity to match expected flows, so we do not anticipate charging this fee. In essence, over-flow charges are designed to offer protection against flowing gas in excess of equipment capacities and are expected to be effective in achieving this objective.

3.2 Balancing charges

To ensure stable and reliable system operations, users have an obligation to ensure that their receipts of gas match their deliveries of gas on a day. If users do not balance their receipts and deliveries, First Gas may need to buy or sell gas to ensure correct functioning of the pipeline system.

If the interconnected party chooses an OBA, they will be liable for balancing charges.

Balancing charges and costs are a recoverable cost under section 3.1.3(1)(b) of the Input Methodologies as any cost, credit or charge, including a cash-out, arising from a balancing regime specified in a transmission access code. Recoverable costs make up part of the Forecast Allowable Revenue for each year, that the transmission business can recover from its customers (please refer to section 4.1 below).

3.2.1 Excess Running Mismatch (ERM) charges

Each day First Gas calculates the amount of gas received by a Shipper or OBA Party taking into account any gas traded with other parties. The difference between this amount and that party’s deliveries from the transmission system is their mismatch. This amount is added to the previous day’s mismatch to give a party’s running mismatch. If this amount is greater than their running mismatch tolerance for the day, the party will be charged $0.50/GJ of running mismatch held. This charging is specified in sections 8.11 to 8.14 of the GTAC and is an incentive on users to balance their position (known as primary balancing).

3.2.2 Allocation of Balancing Gas costs and credits

If First Gas needs to buy balancing gas on a day, the cost of the gas bought is allocated to parties with a negative running mismatch (too little gas in the pipeline). If First Gas needs to sell balancing gas on a day, a credit for gas sold is allocated to parties with a positive running mismatch (too much gas in the pipeline). These costs and credits are made in proportion to each party’s running mismatch in the direction of the transaction. The title to gas bought or sold is also transferred on a similar basis. These transfers and allocations are specified in sections 8.8 to 8.10 of the GTAC.

3.3 Other charges

3.3.1 Interconnection Fees

Interconnection fees are charged where First Gas has built or upgraded an injection or delivery point or other transmission infrastructure to accommodate particular gas flows. These fees are specified in the Interconnection Agreement (ICA) with the end-user and are subject to the First Gas Interconnection Policy.

3.3.2 Non-Standard charges

Where a shipper has a Supplementary Agreement (SA) with First Gas, they will be charged non-standard transmission fees. These are specified in the SA with the shipper and are subject to the First Gas Supplementary Agreements Policy.

4 Pricing methodology

While we have changed our products for transmission services and pipeline balancing, an important aim in developing the pricing for each product has been to minimise customer impacts arising from the change in pricing structure. We have therefore sought to ensure that we are recovering the same revenue from each zone as we recovered under our previous codes. This ensures that Shippers are not disadvantaged by the change to our products and have certainty over costs.

As noted in section 2.1 above, our pricing methodology must ensure that prices set through the GTAC comply with the revenue cap under the DPP Determination. All revenue earned from the use of the gas transmission system to transport gas – transmission fees (standard DNC fees, non-standard fees, underrun and overrun fees) and interconnection fees – are covered by the DPP, and included in the target revenue for the year commencing 1 October 2019.

4.1 Soft launch for the GTAC

To help Shippers adjust to the new transmission products and incentives under the GTAC, we have agreed to a “soft launch” of GTAC incentive charges. Under this approach, incentive fees and excess running mismatch charges will not be charged until 2 February 2020 (around 4 months after the introduction of the GTAC). This ensures that Shippers are not exposed to incentive charges before they are confident of having systems and processes in place to manage their exposure to these fees.

During this period, we will adjust fee settings as follows:

- The overrun/underrun factor ‘F’ in section 11.4 of the GTAC will be set to 1;
- The peaking factor ‘M’ in section 11.5 of the GTAC will be set to 1; and
- ERM fees (F_{NERM} and F_{PERM}) in section 8.14 of the GTAC will be set to \$0 /GJ.

The overrun/underrun and peaking fee settings will ensure that Shippers pay for all units of capacity used on a day. However, there is no additional incentive fee for any deviations from the nomination. In terms of balancing, while we will not charge ERM fees we will pass through balancing gas purchased or sold, which will help to ensure that balancing of the pipeline is maintained. We will also maintain close oversight of how parties fulfil their primary balancing obligations during this period.

To maintain stable revenues, we have adjusted the TPM for the first part of the year as follows:

- ERM revenue estimates have been reduced to zero; and
- The overrun/underrun factor ‘F’ has been set to 1.

We think it is important to make this adjustment to ensure that our allowable revenue is collected during GY2020. While incentive fee revenue is only 3% of our total revenue from standard prices, any under-recovery of revenue in GY2020 would be washed up in GY 2022, which could contribute to pricing instability over time.

4.2 Determining the Target Revenue

To show how we determine our target revenue each pricing year, Table 2 sets out the components that factor into our pricing methodology.

Table 2: Components for inclusion in pricing methodology

Forecast Revenue from Prices	≤	Forecast Allowable Revenue
This equals the: sum of each price multiplied by each corresponding forecast Quantity: DNC including overruns/underruns, peaking charges, auto-nomination charges and overflow charges + Non-Standard Pricing including ICA revenue and SA revenue This is our **Target Revenue** for the pricing year.		This equals the: forecast net allowable revenue + forecast pass-through and recoverable costs, which includes: Rates and levies Balancing gas costs and revenues Mokau Compressor fuel gas costs CAPEX Wash-up Adjustment - ERM charge revenue + opening balance of the wash-up account This is our **Forecast Allowable Revenue** for the pricing year.

Our Transmission Pricing Model calculates the Target Revenue ensuring that the Forecast Allowable Revenue is not exceeded. This is an iterative process, covering the following steps:

1. We calculate the Forecast Allowable Revenue, following the methodology set out in the DPP Determination. This is considered the total allowable revenue;
2. We calculate the Non-Standard Pricing as shown in the table below, which is estimated using the throughput forecasts for the Delivery Points covered by the agreements;
3. The forecast revenue from SAs and interconnection agreements (ICAs) is then deducted from the total revenue base to establish the base for DNC revenue; then
4. The Target Revenue for DNC standard products from Delivery Points and Zones can then be calculated.

The table below shows this process and that the calculated Target Revenue complies with the Forecast Allowable Revenue.

Table 3: Target revenue compliance with forecast allowable revenue

Revenue Component	Amount	
Forecast Allowable Revenue (A)	$130,695,275	
Target Revenue		Proportion of Target Revenue
Non-Standard Pricing		
• ICA Revenue (B)	$909,457	0.7%
• SA Revenue (C)	$24,695,486	18.9%
Standard Pricing		
• DNC Revenue (D)	$105,087,084	80.4%
Target Revenue (E = B + C +D)	$130,692,026	100.0%
Difference (A – D)		
Compliant?	YES	

4.2.1 Target revenue by component

Table 4 identifies the key components of target revenue required to cover the costs and return on investment associated with the First Gas' provision of gas transmission services.

Table 4: Key components of target revenue

Cost Components	$	%
Operational Expenditure	$39,383,273	30%
Pass through and recoverable costs	$4,239,275	3%
Depreciation	$26,941,673	21%
Tax	$15,812,000	12%
Return on capital	$44,315,806	34%
Target revenue	**$130,692,026**	

4.3 Approach to DNC pricing

Once First Gas has determined the base for DNC revenue, this revenue is allocated to each delivery zone and delivery point. The revenue for each Delivery Point and Zone is then allocated based on the following methodology.

- Calculation of the hypothetical revenue for each delivery point and zone under the previous transmission codes using the forecast flows for the 2019/20 gas year:
  - Estimating the forecast VTC charges for each delivery point based on capacity, throughput and overrun charges. This estimate excludes SA and ICA revenue as these non-standard charges are calculated separately;
  - Estimating the forecast MPOC revenue from small welded points, dedicated delivery points and Transmission Pipeline Welded Points (Frankley Road, Pokuru, Pirongia and Rotowaro).
  - Allocation of the Transmission Pipeline Welded Point charges from the MPOC to each delivery point in proportion to the forecast flows for each point under the VTC;
  - Addition of the hypothetical MPOC and VTC revenue to obtain the target DNC revenue recovered per zone or individual delivery point.

- The base DNC Fee for each delivery zone or delivery point was then calculated using the target DNC revenue for each point or zone divided by the sum of the throughput, overrun and underrun volumes as follows:

  DNC Fee = DNC Target Revenue/(Throughput Quantity + Overrun Quantity x F +Underrun Quantity x (F-2))

  Where *F* is defined as per section 3.1.3 of the GTAC. For the period 1 October to 2 February *F* is set at 1. After this period, it is set at 1.5.

- Adjustment of the allocation of the base DNC Fee for each delivery zone or point was then made based on the following:
  - A comparison of the notional per GJ charge unit charge under the previous codes using forecast flows and the same value based on the previous year's capacity bookings. This ensured that there were no large differences in the unit price of gas transmission year on year; and
  - Any macro adjustments to ensure that gas pricing increases as pipeline distance from Taranaki increases and ensure geographic parity between regions.

In making this calculation, the following factors were considered:

- Estimated mass-market load for each zone was assigned the average overrun/underrun percentage for non-mass market load for the entire; and
- Peaking party revenue was not explicitly modelled but was assumed to be the same as overrun/underrun revenue.

4.4 Transmission pricing assumptions

4.4.1 Forecast gas flows

Each year First Gas is required to forecast demand for each transmission access product for the coming year starting 1 October. This forecasting is informed by an independent forecast of gas flows across the network (completed by Aretê Consulting Limited), which is peer reviewed by First Gas staff. These forecasts take account of growth in existing loads as well as known new loads coming onto the transmission system. The forecast delivered quantities were used to estimate the throughput quantities for each non-standard contract and each standard Price Zone.

Non-standard contract capacity quantities were maintained at the same values or the same proportionality to throughput as actuals for 2017/18. It is difficult to foresee how individual users will book capacity and therefore these historic patterns give the best basis for future behaviour under these contracts. Where material changes were required to an existing SA in order to conform with the GTAC, we have accounted for expected changes to gas quantities shipped under the SA.

4.4.2 Establishing Delivery Zones

Delivery zones were defined for all delivery points that were not covered by a SA or treated as individual delivery points. Individual delivery points were identified for users that had very high usage of gas. The following points were identified as being individual delivery points:

- Bertrand Road (Methanex)
- Faull Road (Methanex)
- Huntly Power Station (Genesis Energy)
- Ngatimaru Road (Delivery) (Methanex)

The delivery zones were then established based on operational and geographic considerations. Under the previous VTC methodology, First Gas had been aligning pricing based on geography in preparation for the GTAC for the last few years. Hence the delivery zones follow regional pricing zones already established under the VTC. The zones and delivery points in each zone are given in Table 5 below. The last column of this table shows the delivery points subject to Supplementary Agreements and the delivery zone they would be located in if they were subject to standard pricing. A map of the zones is shown in Figure 2.

Under the GTAC, if a delivery point has an Operational Balancing Arrangement (OBA) as its allocation methodology, the delivery point will be removed from the delivery zone. The delivery point will become an individual delivery point and the price for the delivery point will be the price for the relevant delivery zone in which the delivery point was previously located. As there is a 40-day notice period for implementing the OBA under the GTAC, some points could become individual delivery points during the gas year.

Table 5: Allocation of delivery points to delivery zones

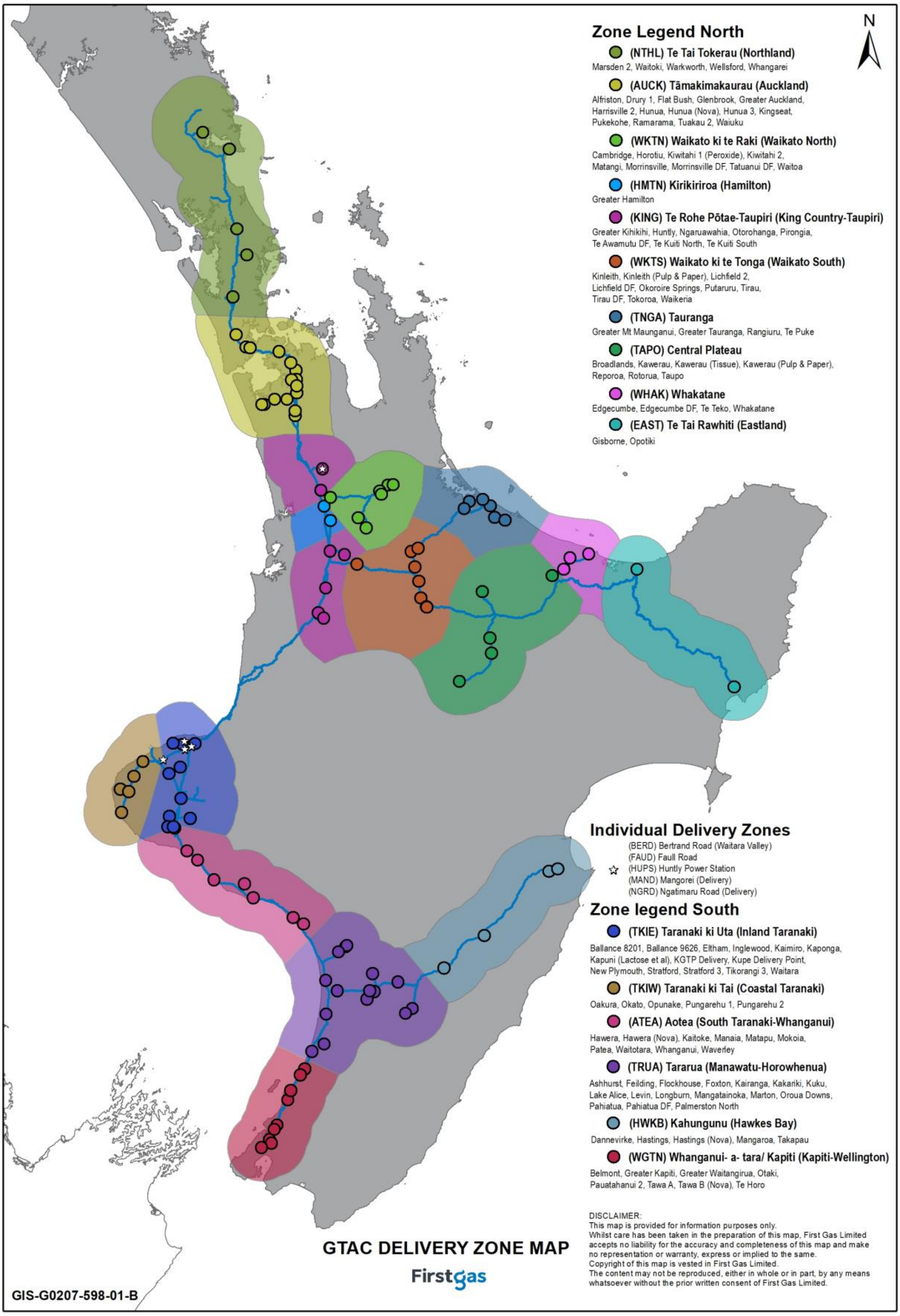
Zone Code	Delivery Zone	Delivery Points	Supplementary Agreements*
NTHL	Te Tai Tokerau (Northland)	Marsden 2, Waitoki, Warkworth, Wellsford, Whangarei	Kauri and Maungaturoto Dairy Factories (Kauri DF, Maungaturoto DF) Refining New Zealand (Marsden 1) Southern Paprika Warkworth (Warkworth)
AUCK	Tāmakimakaurau (Auckland)	Alfriston, Drury 1, Flat Bush, Glenbrook, Greater Auckland (Bruce McLaren, Henderson, Papakura, Waikumete, Westfield), Harrisville 2, Hunua, Hunua (Nova), Hunua 3, Kingseat, Pukekohe, Ramarama, Tuakau 2, Waiuku	Auckland District Health Board (Greater Auckland) CHH Penrose (Greater Auckland)
WKTN	Waikato ki te Raki (Waikato North)	Cambridge, Horotiu, Kiwitahi 1 (Peroxide), Kiwitahi 2, Matangi, Morrinsville, Morrinsville DF, Tatuanui DF, Waitoa	Te Rapa Cogen (Te Rapa Cogen)
HMTN	Kirikiriroa (Hamilton)	Greater Hamilton (Hamilton Te Kowhai, Hamilton Temple View)	
KING	Te Rohe Pōtae-Taupiri (King Country-Taupiri)	Greater Kihikihi (Kihikihi (Te Awamutu), Te Awamutu North), Huntly, Ngaruawahia, Otorohanga, Pirongia, Te Awamutu DF, Te Kuiti North, Te Kuiti South	
WKTS	Waikato ki te Tonga (Waikato South)	Kinleith, Kinleith (Pulp & Paper), Lichfield 2, Lichfield DF, Okoroire Springs, Putaruru, Tirau, Tirau DF, Tokoroa, Waikeria	
TNGA	Tauranga	Greater Mt Maunganui (Mt Maunganui, Papamoa, Papamoa 2), Greater Tauranga (Pyes Pa, Tauranga), Rangiuru, Te Puke	
TAPO	Central Plateau	Broadlands, Kawerau, Kawerau (Tissue), Kawerau (Pulp & Paper), Reporoa, Rotorua, Taupo	
WHAK	Whakatane	Edgecumbe, Edgecumbe DF, Te Teko, Whakatane	Whakatane Mill Limited (Whakatane)
EAST	Te Tai Rawhiti (Eastland)	Gisborne, Opotiki	
TKIE	Taranaki ki Uta (Inland Taranaki)	Ballance 8201, Ballance 9626, Eltham, Inglewood, Kaimiro Mixing Station Delivery, Kaponga, Kapuni (Lactose et al), KGTP Delivery, Kupe Delivery Point, New Plymouth, Stratford, Stratford 3 Delivery Point, Tikorangi 3 Delivery, Waitara	
TKIW	Taranaki ki Tai (Coastal Taranaki)	Oakura, Okato, Opunake, Pungarehu 1, Pungarehu 2	
ATEA	Aotea (South Taranaki-Whanganui)	Hawera, Hawera (Nova), Kaitoke, Manaia, Matapu, Mokoia, Patea, Waitotara, Whanganui, Waverley	

Zone Code	Delivery Zone	Delivery Points	Supplementary Agreements*
TRUA	Tararua (Manawatu-Horowhenua)	Ashhurst, Feilding, Flockhouse, Foxton, Kairanga, Kakariki, Kuku, Lake Alice, Levin, Longburn, Mangatainoka, Marton, Oroua Downs, Pahiatua, Pahiatua DF, Palmerston North	
HWKB	Kahungunu (Hawkes Bay)	Dannevirke, Hastings, Hastings (Nova), Mangaroa, Takapau	
WGTN	Whanganui- a- tara / Kapiti (Kapiti-Wellington)	Belmont, Greater Kapiti (Paraparaumu, Waikanae 2), Greater Waitangirua (Pauatahanui 1, Waitangirua), Otaki, Pauatahanui 2, Tawa A, Tawa B (Nova), Te Horo,	

*Confidential Supplementary Agreements not shown

[+]Greater Kapiti to exist from 1 October 2019

Figure 2: Map of delivery zones



4.4.3 Priority Rights charges

No forecast is required for priority rights revenue, as this is rebated to Shippers within the year it is earned. It therefore does not affect Target Revenue.

4.4.4 Overruns and Underruns

As the overrun/underrun regime is a new feature of pricing we are not able to draw on historical data to understand the potential for underrun or overrun at each zone or delivery point. We have therefore taken a two-step approach to estimating this behaviour:

- Understanding what the potential range of overrun/underrun would be for high, medium and low overrun/underrun users; and
- Assigning each delivery zone and individual delivery point an overrun/underrun category based on the characteristics of the zone or point.

To develop and understand the potential scale of underrun/overrun over a year, we used proxy data to look at the potential for overrun at each delivery point and delivery zone as follows:

- VTC system: Data from Balancing and Peaking Pool (BPP) receipts in relation to deliveries;
- Maui system: Data from intra-day 4 nominations in relation to actual flows.

This approach is consistent with the GIC's approach to evaluating the likely magnitude of overruns and underruns in its assessment of the GTAC.

The range of overrun/underrun for each category of zone or point is shown in the table below.

Table 6: Potential for underrun or overrun

Overrun/underrun Category	Underrun	Overrun
Low	1.00%	1.00%
Low / Medium	2.00%	2.30%
Medium	4.00%	4.60%
Medium / High	5.00%	5.75%
High	6.00%	6.90%

Once the percentage of the overruns and underruns were determined for each category, each zone was assigned a category. The categorisation for each delivery zone based on the following assumptions:

- Delivery zones with large forecast volumes and number of users zones were assumed to have a lower overrun/underrun category due to the portfolio effect of multiple end users;
- Delivery zones with low forecasted volumes were assumed to have a higher overrun/underrun category due to variable and seasonal loads across a small amount of end users;
- Delivery zones with large maximum and minimum 95% monthly confidence intervals (CI) around the forecast were assumed to have a higher overrun/underrun category, since the higher variability of loads would be harder for Shippers to forecast;
- Delivery zones with small 95% monthly CIs from the forecast were assumed to have a lower overrun / underrun categories as the lower variability of loads would be easier for Shippers to forecast; and
- Delivery zones with a high mass market load would have harder to forecast and therefore have a higher overrun/underrun category.

During consultation, Shippers raised concerns regarding the allocation of overrun/underrun charge categories. These categories were revised based on consultation and changes are noted in Table 7.

Table 7: Allocation of underrun/overrun categories

Delivery Zone/Individual Delivery Point	Forecast Volumes (GJ)	Max 95% CI	Min 95% CI	Mass market load (%)	Initial Overrun/ Underrun Category	Final Overrun/ Underrun Category	Comments
Te Tai Tokerau (Northland)	268,693	30%	18%	44%	Medium	Medium	Low forecast volume with high mass market load
Tāmakimakaurau (Auckland)	16,403,213	8%	6%	34%	Low	Low	Large forecast stable volume with stable TOU load
Waikato ki te Raki (Waikato North)	2,164,317	41%	20%	7%	Medium-High	Medium-High	Medium forecast volume with large 95 % CI
Kirikiriroa (Hamilton)	1,684,009	26%	15%	60%	High	High	Medium forecast volume with high mass market load and moderate 95% CI
Te Rohe Pōtae-Taupiri (King Country-Taupiri)	739,578	105%	35%	5%	High	High	Low forecast volume with large 95% CI
Waikato ki te Tonga (Waikato South)	4,663,448	25%	20%	3%	Medium-High	Low-Medium	Large forecast volume with low mass market load and moderate 95% CI. Change to conform with other zones.
Tauranga	1,100,247	9%	7%	46%	Low	Low	Medium forecast volume with small 95% CI and medium mass market load
Central Plateau	1,713,175	10%	7%	23%	Low	Low-Medium	Medium forecast volume with small 95% CI. Increase in category to reflect information received during consultation.
Whakatane	1,351,862	59%	17%	2%	Medium-High	Medium-High	Medium forecast volume with large 95% CI
Te Tai Rawhiti (Eastland)	476,533	15%	14%	37%	Medium	Medium	Low forecast volume with medium mass market load and moderate 95% CI
Taranaki ki Uta (Inland Taranaki)	12,535,343	8%	7%	3%	Low-Medium	Low	High forecast volume with low mass market load and small 95% CI. Reduction in category to reflect large TOU loads in zone
Taranaki ki Tai (Coastal Taranaki)	17,067	77%	43%	100%	Medium-High	Medium-High	Low forecast volume with high mass market load and large 95% CI
Aotea (South Taranaki-Whanganui)	1,428,390	23%	14%	28%	Medium-High	High	Medium forecast volume with large 95% CI. Increase in category to reflect information received during consultation.
Tararua (Manawatu-Horowhenua)	2,667,748	30%	18%	35%	Medium-High	Medium-High	Medium forecast volume with moderate mass market load and high 95% CI
Kahungunu (Hawkes Bay)	2,289,125	10%	7%	18%	Low-Medium	Low-Medium	Medium forecast volume low 95% CI and moderate mass market load
Whanganui- a- tara / Kapiti (Kapiti-Wellington)	4,164,973	15%	12%	81%	Low-Medium	Medium	Large forecast volume with high mass market load. Increase in category to reflect information received during consultation.
Bertrand Road (Waitara Valley)	16,000,000	n/a	n/a	0%	Low	Low	Large volume with large TOU load
Faull Road	14,000,000	n/a	n/a	0%	Low	Low	Large volume with large TOU load

Delivery Zone/Individual Delivery Point	Forecast Volumes (GJ)	Max 95% CI	Min 95% CI	Mass market load (%)	Initial Overrun/ Underrun Category	Final Overrun/ Underrun Category	Comments
Huntly Power Station	25,000,000	n/a	n/a	0%	Low	Low	Large volume with large TOU load
Mangorei Delivery Point	500,000	n/a	n/a	0%		Low	Large volume with large TOU load
Ngatimaru Rd Delivery	44,000,000	n/a	n/a	0%	Low	Low	Large volume with large TOU load

4.4.5 Peaking charges

The revenue for peaking charges was assumed to be the equivalent to that from overrun/underrun charges and therefore no specific forecast was generated.

4.4.6 Auto-nomination charges

The percentage of mass market load was separated out for each zone and the average of the overrun and underrun for the remaining load over the network was calculated based on the method described in section 4.3. This generated the revenue from the auto-nomination charges.

4.4.7 Over-Flow charges

As these charges are an exception, no forecast was generated for these charges. We do not expect to charge under this section during the 2019/20 gas year.

4.5 Approach to prices and revenue for non-standard contracts

Non-Standard contracts for the gas transmission system include SAs and ICAs.

Prices for these contracts are a combination of ongoing contracts on a set price path under a TPA and contracts that are renewed on an annual basis. Contracts that are to be renewed have had their 2019/20 prices increased by the 2019 March annual weighted average Consumer Price Index (CPI), as published by Statistics New Zealand.

The renewed contracts have also been renegotiated as appropriate to comply with the new GTAC code. There will be 12 Non-Standard Contracts for the 2019/20 gas year. These are set out in Table 8.

As the VTC had a different pricing methodology and extent of service than the GTAC, we have needed to amend some contract details to incorporate transmission prices that would have been charged under the MPOC into these contracts to ensure that they work under the GTAC. This has been achieved by adding the prevailing fees for transport under the MPOC as a variable fee to each contract.

There are also some non-standard contracts where the delivery points for gas no longer exist, despite the contract remaining on foot for some years to come. However, the economic benefits and obligations of these contracts endure. Therefore, we have needed to ensure that Shippers with these contracts retain the economic benefits of these contracts despite the change in code. This ensures that customers with these contracts do not suffer price shocks or other adverse commercial outcomes simply due to the change in code. This approach also reduces the potential for losing demand (and therefore revenue) from the system which would negatively impact other all transmission system users.

As a result, we have had to reassign the benefits and obligations of one contract to a different delivery point to ensure that the same amount of revenue is collected from this Shipper. This does not impact other Shippers but does make back comparison for standard pricing more difficult.

The prices under the non-standard contracts are multiplied by the forecast quantities to give the forecast 2019/20 revenue for non-standard contracts ($24.7 million). This represents 19% of our revenue.

4.5.1 Extent of non-standard contracts

The GTAC provides more explicit criteria for the use of non-standard contracts than the VTC. There are also provisions for greater transparency around the decision to enter into the non-standard contracts than in the VTC. When deciding to enter into a non-standard contract, First Gas is required to publish our reasons for entering into such an agreement. This ensures that the use of non-standard contracts is limited to necessity.

In considering a request for a SA, we are required to consider the following factors under section 7.1 of the GTAC:

- The amount of transmission capacity requested, including whether providing it would affect Available Operational Capacity to the extent of impeding or forestalling opportunities more beneficial to First Gas and other users of the Transmission System;
- Whether the Shipper (or End-user) can demonstrate that it has a practical opportunity to bypass the Transmission System or use an alternative fuel that is cheaper than Gas;
- Whether the Shipper (or End-user) can demonstrate that paying First Gas' standard transmission fees would be uneconomic; and
- Whether the Shipper (or End-user) is the sole user of the relevant Delivery Point or other transmission assets and those assets would cease to be useful were the End-user to cease using Gas.

The use of interruptible agreements is limited to situations where such an agreement will improve or maximise use of available capacity and we will have consideration as to whether the end-user has a source of alternate fuel.

First Gas is in the process of consulting on its Supplementary Agreements Policy, which it will publish in parallel with this Transmission Pricing Methodology. This document will provide 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.

4.5.2 Methodology for non-standard prices

The prices for non-standard contracts are set to reflect the circumstances of the specific Shipper/end-users. In all cases, prices are tested to ensure they are not less than incremental cost of supply 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 achieves greater alignment with the Pricing Principles, as demonstrated in **Appendix 2**.

4.5.3 Obligations around service interruptions

The ID Determination[5] requires First Gas to describe our obligations and responsibilities (if any) to consumers subject to non-standard contracts if the supply of gas transmission services to the consumer is interrupted.

Our obligations for the provision of transmission capacity under (standard) transmission services agreements and (non-standard) SAs (excluding interruptible agreements) are comparable.

The GTAC requires First Gas to curtail consumers on interruptible agreements before restricting Shippers' standard capacity or supplementary capacity. The order of curtailment is prescribed in section 10.3 of the GTAC.

The treatment of supplementary capacity in this order will be defined in the SA and will follow the Supplementary Agreement Policy which is currently under consultation.

A Shipper whose firm capacity is curtailed is entitled to a rebate of any fixed transmission fees and will not be charged for any variable transmission fees.

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

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[5] Clause 2.4.5(2) of the ID Determination.

4.5.4 Non-standard agreements in this TPM

The non-standard agreement in this TPM are set out in Table 8.

Table 8: Non-standard agreements in this TPM

Agreement name	Delivery Point	'Expiry date' as defined in VTC SA	Date signed	Linked to a TPA?	Reason for agreement	Capacity	Transmission fee basis	Revenue
Supplementary Agreement (Te Rapa Cogeneration Plant)	Te Rapa Cogeneration Plant	30 June 2023	13 May 2015		Physical bypass	mdq 23,200 GJ; mhq 1,092 GJ	Fixed fee ($/day); variable fee ($/GJ); (daily) overrun fee ($/GJ)	$9,657,497
Supplementary Agreement (CHH Penrose)	Greater Auckland	30 Sep 2021	25 Sep 2015		Physical bypass	mdq: 1,600 GJ; mhq: mdq/20	Fixed fee ($/GJ.mdq); (daily) overrun fee ($/GJ)	
Confidential Supplementary Agreements (4)								
Supplementary Agreement (Auckland District Health Board)	Greater Auckland	30 Sep 2019	3 Sep 2018	Yes	Encourage new use of gas	mdq: 1,451 GJ; mhq: mdq/16	Fixed fee ($/day); variable fee ($/GJ); (daily) overrun fee ($/GJ)	$10,141,249
Supplementary Agreement (Marsden Point)	Marsden 1	30 Sep 2019	28 Jan 2019	Yes	Investment certainty for First Gas	mdq: seasonal profile, 13,600 to 15,600 GJ; mhq: mdq/24	Fixed fee ($/GJ.mdq); variable fee ($/GJ); (daily) overrun fee ($/GJ)	
Interruptible User Contract (New Zealand Refining Company)	Marsden 1	30 Sep 2019	21 Dec 2018	Yes	To access capacity above firm limit	mdq: approved NQ; mhq: approved NQ/24	Fixed fee ($/GJ.mdq); (daily) overrun fee ($/GJ)	
Supplementary Agreement (Whakatane Mill)	Whakatane	30 Sep 2019	28 Sep 2018		Alternative fuel	mdq: 3,400 GJ; mhq: 176 GJ	Fixed fee ($/day); variable fee ($/GJ); (daily) overrun fee ($/GJ)	$4,868,724
Supplementary Agreement (Kauri & Maungaturoto Dairy Factories)	Kauri, Maungaturoto	30 Sep 2019	11 Dec 2018		Alternative fuel	mdq: seasonal profile, 2,500 to 5,000 GJ; mhq: mdq/20 with max. 130 GJ per DP	Fixed fee ($/GJ.mdq); variable fee ($/GJ); (daily) overrun fee ($/GJ)	
Supplementary Agreement (Southern Paprika)	Warkworth	30 Sep 2019	27 Aug 2018		Alternative fuel	mdq: 1,500 GJ; mhq: 73 GJ	Fixed fee ($/GJ.mdq); variable fee ($/GJ); (daily) overrun fee ($/GJ)	
Total Supplementary Agreement Revenue								$24,467,470

4.6 Forecasting balancing and pass-through costs

As explained in section 4.1 (above), Forecast Allowable Revenue includes amounts defined in the Input Methodologies as pass-through and recoverable costs. A total of 5 different types of these costs are aggregated together for this year when setting transmission prices. Each of these are specified in sections 3.1.2 and 3.1.3 of the Input Methodologies and summarised below.

4.6.1 Rates and levies

The following costs are included in this category:

- *Property rates* from the 2017/18 gas year were used as a basis. These were increased by CPI;
- *Commerce Act Levies* have been assumed to be the same as the 2017/18 gas year. The Commerce Commission has released its major projects timetable, which does not include any projects in the gas sector. Hence last year's levies are an appropriate estimate for the coming year; and
- *Utilities Disputes Levies* were revised in 2018 and will take effect in early 2020. The specified value was given in clause 1.10.2 (d) of the General and Scheme Rules for the Energy Complaints Scheme.

The forecast values for 2019/20 are shown in the Table 9.

Table 9: Forecast values for rates and levies

Pass-through cost	Amount
Commerce Commission levies	$832,268
Gas Industry Company levies	$33,000
Rates	$1,673,596
Total	**$2,538,864**

4.6.2 Balancing gas costs and revenues

Balancing gas costs were calculated based on the volumes of gas bought and sold during gas year 2017/2018. The First Gas average buy/sell price for the first two months of 2019 was used as to price the gas. Market pricing shifted significantly upwards at the end of 2018 due to market conditions and the change to a one-to-one surrender ratio for carbon units. It is therefore prudent for pricing after this shift to be used to calculate these costs.

While we have based the volume of gas bought and sold on the amounts during the year 2017/18, the balancing regime under GTAC has changed from that of previous codes. We believe that the incentives on users to balance their position will be stronger under the GTAC than under current arrangements. For this reason, we have reduced volumes by 50%. The total costs are shown in the Table 10.

Table 10: Forecast balancing costs and revenues

Balancing gas costs	Volume GY 2017/18	Forecast Volume 2019/20	First Gas Average Price ($/GJ)	Amount ($)
Total gas bought	546,524	273,262	$10.64	$2,908,532.41
Total gas sold	663,250	331,625	$8.59	-$2,848,137.17
Total bought and sold	1,209,774	604,887		
Trading costs			$0.08	$45,366.53
Total costs				**$105,761.77**

4.6.3 Excess Running Mismatch (ERM) charges

ERM is a new feature of the balancing regime under the GTAC. These charges are levied when the running imbalance held by a shipper or OBA party exceeds a specified tolerance. We believe that this mechanism provides a stronger incentive to balance than automatic cash outs previously applied under the MPOC since there is no change in gas title (parties are still required to correct any imbalance). We have used the absolute value of cash out gas bought and sold during the period 2016 – 2018 as a basis for potential ERM volumes. However, as we think the incentive to balance is stronger under the GTAC, we have reduced these volumes by 50%.

The value of the ERM charge revenue was calculated by multiplying the volume derived above by the current ERM fee $0.50/GJ noting that the ERM fee prior to 2 February 2020 will be $0/GJ. Table 11 below shows the calculation of this amount. This figure is deducted from the Forecast Allowable Revenue.

Table 11: ERM charge revenue calculation

Gas Year	Absolute Cash Out Volume (GJ)	ERM Charge Value ($)
GY 2018	1,933,776	$966,888
GY 2017	1,734,838	$867,419
GY 2016	1,948,167	$974,083
50% of 3-yearly average		$468,065
ERM charge value		**$312,043**

4.6.4 Mokau compressor fuel gas costs

Due to its role in balancing the Maui pipeline, Mokau compression is treated as a recoverable cost under the Input Methodologies. Mokau fuel gas costs were calculated by using average volumes from the 2016/2017 and 2017/2018 gas years. We used the average market price for the first two months of 2019to price this gas. For the reasons given in section 5.5.2 we believe this to be an appropriate price due to changes in the market at the end of 2018. The resulting costs are shown in the Table 12.

Table 12: Forecast Mokau compressor fuel gas costs

	Average Fuel Gas Volumes (GJ)	Average Market Price ($/GJ)	Amount ($)
Mokau fuel gas	190,548	$9.74	$1,855,763.14
Trading costs		$0.08	$14,291.14
Total			**$1,870,054.27**

4.6.5 Revenue cap wash-up

The revenue cap wash-up amount is calculated and published as part of First Gas' Default Price Path (DPP) Compliance Statement (issued within 50 days of the end of the pricing year).[6] A time value of money adjustment as prescribed in the DPP Determination is applied to the calculated raw amount. The value for GY 2020 reflects a reduction in our allowable revenue of $719,000.

[6] First Gas' compliance statements for our gas transmission business are available on our website here: https://firstgas.co.nz/about-us/regulatory/transmission/

4.6.6 CAPEX wash-up adjustment

The Capex wash-up adjustment is a recoverable cost that can be added to prices for years 2 – 5 of the DPP period to reflect "the difference between the revenues for a DPP regulatory period using the actual values of commissioned assets for a prior regulatory period, and the revenues using forecast commissioned assets applied by the Commission when setting prices".

The intent of the Capex wash-up adjustment is to ensure regulated businesses are in approximately the same position (in terms of allowable revenue), had the actual opening Regulated Asset Base been known when revenue for the DPP period were reset. The value for GY 2020 is $755,000.

4.7 Pricing for subsequent years

4.7.1 Additional data in subsequent years

While the comparison for the first year of the GTAC looks back to the previous codes and approaches, in the second year of GTAC operation pricing First Gas will be able to consider the following data from the first year of GTAC operation:

- Transmission revenue in each Delivery Zone and Delivery Point;
- Overrun and underruns in each Delivery Zone and Delivery Point;
- Actual performance of the specified shipper auto-nomination algorithm;
- Shipper and OBA balancing over the system;
- First Gas balancing gas sales and purchases;
- Mokau compressor operations; and
- Any overflow charges (which we expect to be zero).

We therefore anticipate that the assumptions underpinning this TPM will be tested and revised with operating experience. We will review these factors in 2020 to ensure we have a pricing methodology that improves as the information available to us increases.

4.7.2 Loss of a significant load

The revenue effect of losing a major load varies depending on the location of the load on the system: the loss of a load on the ex-Maui system will have a much lower revenue impact than the loss of the same size load in Northland. This is due to the proximity of the loads to Taranaki and the difference in assets, costs and pricing between the ex-Maui and ex-Vector systems.

We see two choices when faced with losing a large load:

- Retain revenue collection for the zone affected by increasing prices in that zone; or
- Spread the loss over the entire system.

In the first case, First Gas would be required to collect the same revenue from a smaller volume of load in the same zone. This could disproportionately raise prices in that zone and potentially create issues of geographic parity with adjacent regions. For this reason, we are likely to remove the revenue from the zone and spread the increase over the entire system.

4.7.3 Alignment with cost reflective prices

We have not undertaken work for this TPM to demonstrate how our prices fall within the wide boundaries of incremental and standalone costs. Vector has demonstrated the range between standalone cost and incremental in its TPM based on work undertaken in 2012 by PriceWaterhouseCoopers (PWC). This work implied transmission pricing caps of between $4.20/GJ for large industrial coal users and $39.05/GJ for smaller domestic LPG users. A summary of the PWC study is provided in our GY2018 Transmission Pricing Methodology (on page 36) available on our website.[7]

Given the very high standalone costs and the low incremental cost of service, we did not seek to demonstrate pricing compliance within this range. However, several stakeholders have asked us to engage further on this subject in order to build future confidence on the efficiency of our pricing.

We agree that further work to understand standalone costs and incremental costs of serving different customers is appropriate. While we understand the capital and operating costs of our network, we will need further input from stakeholders for this work to be successful. We need to understand:

- Which alternate fuels need to be considered to fully understand standalone costs;
- The impact of transmission price changes on the economics of gas use; and
- An appropriate place for prices to sit in the range between incremental and standalone costs, and whether this should be a fixed level across the network or tailored to particular locations or users.

We therefore propose to engage with stakeholders in early 2020 prior to undertaking this study.

4.7.4 Development of a pricing strategy

Our TPM has focused on achieving price stability for GY 2020. We have not yet sought to build a longer-term pricing strategy, as our focus has been on maintaining price stability in the first year of the GTAC. We have continued existing price paths that equalise pricing between geographically contiguous areas, such as Hamilton. However, we have not sought to further move prices on from existing relativities. Recent TPMs from First Gas have had a similar scope, as the focus was on ensuring a smooth transition to the GTAC transmission products.

We acknowledge that a longer-term view is desirable for industry. We see that longer-term view being built together with industry to ensure that we co-create a pricing environment that meets current and potential future needs of the industry as well as ensuring increased utilisation of the pipeline. Important factors in this discussion are:

- The extent to which pricing becomes strictly cost reflective given that this could discourage new load on the system; and
- The rate of change in any prices that diverge from a cost-reflective approach, given the need to ensure that load is not lost due to price shocks.

We believe that work on developing cost reflective pricing for the transmission system needs time and, most importantly, consultation with stakeholders. We need to understand stakeholder views on the scope of our cost of service review, to what extent pricing should be cost reflective, and how quickly pricing should move towards this goal. Given the current workload in the industry we are reluctant to push consultation too quickly as the quality of consultation (and therefore the resulting work) will suffer.

We propose that we commence consultation on this issue in early 2020 and develop the work over 2020 and 2021. The GY2021 TPM would continue pricing based on revenue stability per zone as per the current TPM, with any changes to prices arising from the work introduced from GY2022. The proposed workplan is set out in the table below.

Table 13: TPM Pricing strategy consultation process

Timeframe	Detail
Early 2020	First Gas internal analysis on network costs for standalone cost versus incremental cost model

[7] https://firstgas.co.nz/wp-content/uploads/First-Gas-GTB-pricing-methodology-PY2019.pdf .

February 2020	Consultation with stakeholders scoping final cost of service model analysis
March to June 2020	Develop GY21 TPM based on current methodology
Late 2020	Complete cost of service model development
End 2020	Consultation on cost of service model and appropriate rates of change for pricing to inform draft pricing strategy
End 2020	Development and approval of pricing strategy
Early 2021	Development of GY2022 TPM
May 2021	Consultation on GY2022 TPM
June 2021	Refinement of GY2022 TPM based on outputs of consultation
30 June 2021	First Gas will notify stakeholders of final TPM and Prices

5 Consultation with stakeholders

First Gas developed the new gas transmission code (the GTAC) in consultation with Shippers, gas producers, major gas users and other stakeholders. The Gas Industry Company (GIC) then consulted on the merits of the new arrangements to determine that the GTAC is materially better than existing codes. The GTAC development process took more than 2 years and involved numerous workshops and meetings with the sector. We aimed to provide our customers and other stakeholders with a seamless solution to transporting gas from the injection points to the various delivery points across the North Island. Background on the GTAC development process is available on the GIC website.[8]

During the GTAC consultation period, workshops were held to establish how pricing would work under the GTAC. Draft prices were circulated in 2018 during the consultation period to give stakeholders an indication of possible pricing impacts. It was agreed that final prices would be determined once the GTAC had received final approval from the Gas Industry Company (GIC). This approval was received in February 2019.[9] Consultation on the TPM itself was undertaken during May 2019.

5.1 Development of the TPM

The process for developing this TPM is set out in Table 10.

Table 14: TPM consultation process

Timeframe	Detail
August 2016 to October 2018	The GTAC Framework developed and pricing structure / charges were determined.
February 2019	Final Assessment Paper was released from the Gas Industry Company (GIC) approving the GTAC
19 April 2019 to 17 May 2019	Draft Gas Transmission Pricing Methodology and provisional prices released to stakeholders for consultation and feedback.
1 May 2019	Gas Transmission Pricing workshop held to discuss the Draft Transmission Pricing Methodology document.
31 May 2019	First Gas publish a summary and response to submissions by interested parties on the draft TPM and draft prices. Any agreed changes to TPM or prices will be made accordingly.
30 June 2019	First Gas will notify stakeholders of final TPM and Prices

5.2 Summary of feedback received on draft TPM

A summary of the feedback received during consultation is given in Table 15. We have also provided a full report on consultation in the following document: https://firstgas.co.nz/wp-content/uploads/GTAC-Transmission-Pricing-Methodology-First-Gas-Response-to-Stakeholder-Submissions.pdf.

[8] https://www.gasindustry.co.nz/work-programmes/transmission-pipeline-access/developing/
[9] https://www.gasindustry.co.nz/work-programmes/transmission-pipeline-access/developing/gtac-final-assessment-paper/

Table 15: Summary of TPM consultation feedback

Topic	Consultation feedback	First Gas response
Maintaining price stability	Stakeholders were largely supportive of this objective and were generally in agreement that this objective had been met. Submitters did take issue with comments that we could not guarantee stability to end-users	We are pleased with the support for the objective of price stability
Treatment of Supplementary Agreements	Further detail was requested on the Supplementary Agreements in the TPM and the treatment of existing supplementary agreements in preparation for the GTAC. The absence of a Supplementary Agreement Policy was questioned.	We have taken a view of ensuring revenue stability for the treatment of Supplementary Agreements to ensure the economic benefits of existing agreements remain. This will minimise price shock and keep load on the system. The Supplementary Agreement Policy relates to the information to be supplied and criteria for obtaining a supplementary agreement rather than the pricing. The policy is therefore not required at this stage.
Extent of Compliance with Commerce Commission Pricing Principles	First Gas has not undertaken specific work to show the prices are compliant with the Commerce Commission Pricing Principles. Stakeholders would like to see more information on this point.	The requirement under our DPP is that we need to show the extent we are consistent with the Commerce Commission Pricing Principles. We believe that previous work demonstrates the large range between standalone cost and incremental pricing, and that revenues earned at various locations across the network fall within this range. However, we agree that further work on cost reflective pricing would be beneficial. This will need to be developed in consultation with stakeholders.
Pricing strategy	While stakeholders recognised the first year objective of price stability, they were concerned over the lack of information on long term development of pricing in terms of a move to cost reflective pricing and the rate of change. Stakeholders were concerned about the potential for a loss of a large load from the transmission system.	We agree that this information would be useful. Moreover, we think that this strategy needs inputs from stakeholders. We therefore propose the process set out in section 4.7 to co-create the strategy. We have taken the approach that the loss of a large load from the system would result in the lost revenue being recovered from charges across the system (rather than at any particular location on our network).
Estimated overrun/underrun fees	Concerns were raised that these fees were underestimated in relation to actual potential performance, which would result in over-recovery of revenue. However, other stakeholders suggested it was better to be prudent to ensure cost recovery.	We have revised the assignment of percentages to individual zones but kept the overall percentages the same. As this is a new mechanism it is difficult to predict shipper accuracy.
Delivery zone naming and codes	Shippers requested four letter codes for each delivery zone and point.	These codes have been provided in consultation with Shippers. There are no changes to individual gas gate codes.
Huntly Power Station pricing	Huntly Power Station pricing is much less than adjacent zones.	Pricing has been maintained to ensure consistency of revenue generation from Huntly Power Station

Topic	Consultation feedback	First Gas response
		and its owner Genesis Energy between the VTC/MPOC and the GTAC. Huntly Power Station was connected to the Maui pipeline which had lower tariffs than adjacent VTC areas.
Huntly Power Station volumes	Genesis energy raised the issue that the 22PJ throughput forecast was low.	We have updated this forecast to 25PJ to reflect current thinking on expected usage (and compared this to historic volumes to test credibility)
Bertrand Road and Faull Road tariffs	Methanex suggested that pricing could be equalised for their Bertrand Road and Faull Road delivery points.	We agree with Methanex and have changed the TPM accordingly to align prices at Bertrand Road and Faull Road.
Improvements in TPM information	Stakeholders requested that delivery points subject to Supplementary Agreements be shown in Table 5 to show the delivery zone in which they would lie if they were subject to standard pricing. Further detail was requested on the values for the components of pass-through and recoverable costs.	This change has been made in the TPM. Additional detail has been inserted in section 4.6.

5.3 Consequential amendments to the TPM following consultation

As a result of these submissions we have made the changes in Table 16 to the prices published in this TPM.

Table 16: Consequential changes to the TPM following consultation

Area	Change
Estimates of underrun and overrun percentages	Reviewed the overrun and underrun percentage estimates for each delivery zone
Delivery zone and individual delivery point naming	Added four letter codes for the identification of delivery zones as per the names in Table 5.
Huntly Power Station volumes	Increased the forecast of Huntly Power Station volumes to 25,000,000 GJ.
Bertrand Road and Faull Road Pricing	Single, homogenised price across the Bertrand Rd and Faull Rd individual delivery points.
Delivery zone table	Add in delivery points subject to supplementary agreements to Table 5 of the TPM to show which zone they would be in if they were subject to standard pricing.
Calculation of pass-through and recovery costs	More detail on the calculation of the pass-through and recover costs in an additional appendix to the TPM.
Pricing Strategy	Insert information on the proposed consultation process to develop the pricing strategy as outlined in section 5.4 of this document.

In undertaking the revisions of the Draft TPM we also identified errors in the Draft TPM that have been addressed. These are outlined in Table 17 below along with a subsequent amendment brought to our attention following consultation.

Table 17: Additional changes to the Draft TPM

Area	Change
Treatment of Excess Running Mismatch Charges	Excess Running Mismatch charges were added to recoverable costs in the Draft TPM when they should have been deducted from these costs
Mangorei delivery point	The new Mangorei delivery point on the 400 line for the Junction Rd peaking power station that will commence operation during 2020 was added as an individual delivery point
Ngatimaru Road Delivery bypass	Following the issue of the TPM Methanex engaged with First Gas on the potential bypass opportunity at the Ngatimaru Road delivery point. We are in discussions with them to avoid this bypass.
Soft launch for GTAC	Separately to the TPM consultation, Shippers raised concerns relating to their ability to adapt to the new regime and requested a more gradual introduction of incentive fees. Their concern focussed on the timing of the IT changes required for GTAC and the additional resources that would be required if they were not able to develop their systems in time. In order to assist Shippers in this matter we have agreed to a 'soft launch' of the GTAC where incentive fees and excess running mismatch charges are not charged until 2 February 2020. Accordingly, we will adjust pricing for the first part of the year such that the daily nominated capacity incorporates this revenue.

6 Final 2019/20 pricing schedule

The resulting pricing schedule for each zone and individual delivery point on standard prices is given in the table below. The forecast revenue generated for each zone and individual delivery points is also provided. Under the GTAC, if a delivery point has an Operational Balancing Arrangement (OBA) as its allocation methodology, the delivery point will be removed from the delivery zone. The delivery point will become an individual delivery point and the price for the delivery point will be the price for the relevant delivery zone in which the delivery point was previously located. As there is a 40-day notice period for implementing the OBA under the GTAC, some points could become individual delivery points during the gas year

Table 18: GY 2019/20 pricing schedule

Code	Delivery Zone / Individual Delivery Point	DNC Fee ($/GJ)		DNC (GJ)	Underruns (GJ)	Overruns (GJ)	DNC Revenue ($)	Underrun Revenue ($)	Overrun Revenue ($)	Total Revenue ($)
		Draft	Final							
NTHL	Te Tai Tokerau (Northland)	$2.19	**$2.20**	268,693	7,604	8,590	$591,125	($11,152)	$25,196	$605,168
AUCK	Tāmakimakaurau (Auckland)	$1.96	**$1.93**	16,403,213	181,533	185,145	$31,658,201	($233,573)	$476,440	$31,901,068
WKTN	Waikato ki te Raki (Waikato North)	$2.00	**$1.91**	2,164,317	102,607	117,797	$4,133,845	($130,653)	$299,988	$4,303,181
HMTN	Kirikiriroa (Hamilton)	$1.36	**$1.37**	1,684,009	53,397	60,061	$2,307,092	($48,769)	$109,712	$2,368,035
KING	Te Rohe Pōtae-Taupiri (King Country-Taupiri)	$1.90	**$1.91**	739,578	42,638	48,984	$1,412,594	($54,292)	$124,746	$1,483,048
WKTS	Waikato ki te Tonga (Waikato South)	$2.02	**$2.02**	4,663,448	92,244	105,884	$9,420,165	($124,223)	$285,180	$9,581,123
TNGA	Tauranga	$2.25	**$2.22**	1,100,247	12,587	12,914	$2,442,548	($18,628)	$38,224	$2,462,144
TAPO	Central Plateau	$2.24	**$2.22**	1,713,175	31,549	35,758	$3,803,249	($46,692)	$105,844	$3,862,400
WHAK	Whakatane	$2.29	**$2.25**	1,351,862	66,776	76,763	$3,041,690	($100,164)	$230,289	$3,171,814
EAST	Te Tai Rawhiti (Eastland)	$2.87	**$2.86**	476,533	14,300	16,211	$1,362,884	($27,266)	$61,818	$1,397,436
TKIE	Taranaki ki Uta (Inland Taranaki)	$0.40	**$0.42**	12,535,343	126,337	126,540	$5,264,844	($35,374)	$70,862	$5,300,332
TKIW	Taranaki ki Tai (Coastal Taranaki)	$0.40	**$0.42**	17,067	224	235	$7,168	($63)	$132	$7,237
ATEA	Aotea (South Taranaki-Whanganui)	$1.74	**$1.76**	1,428,390	66,839	76,332	$2,513,966	($78,424)	$179,125	$2,614,667
TRUA	Tararua (Manawatu-Horowhenua)	$1.80	**$1.84**	2,667,748	98,576	112,113	$4,908,656	($120,920)	$275,050	$5,062,786
HWKB	Kahungunu (Hawkes Bay)	$1.89	**$1.91**	2,289,125	43,001	48,915	$4,372,229	($54,755)	$124,571	$4,442,045
WGTN	Whanganui- a- tara / Kapiti (Kapiti-Wellington)	$2.04	**$2.05**	4,164,973	76,143	83,109	$8,538,195	($104,063)	$227,166 $255,562	$8,715,709
BERD	Bertrand Road (Waitara Valley)	$0.17	**$0.12**	16,000,000	160,000	160,000	$1,920,000	($9,600)	$28,800	$1,939,200
FAUD	Faull Road	$0.07	**$0.12**	14,000,000	140,000	140,000	$1,680,000	($8,400)	$25,200	$1,696,800
HUPS	Huntly Power Station	$0.57	**$0.37**	25,000,000	250,000	250,000	$9,250,000	($46,250)	$138,750	$9,342,500
MAND	Mangorei Delivery Point	NA	**$0.11**	500,000	5,000	5,000	$55,000	($275)	$825	$55,550

Code	Delivery Zone / Individual Delivery Point	DNC Fee ($/GJ) Draft	DNC Fee ($/GJ) Final	DNC (GJ)	Underruns (GJ)	Overruns (GJ)	DNC Revenue ($)	Underrun Revenue ($)	Overrun Revenue ($)	Total Revenue ($)
NGRD	Ngatimaru Rd Delivery	$0.11	**$0.11**	44,000,000	440,000	440,000	$4,840,000	($24,200)	$72,600	$4,888,400

6.1 Changes in prices compared to previous year

As this is the first pricing year under the GTAC and a new pricing product offered, there are no prior year DNC prices for comparison. Our aims in developing pricing have been to ensure:

- Consistency of pricing to Shippers to avoid price and revenue shock. We believe that keeping unit prices per zone ($/GJ transported) within 10% of last year's prices (if they had been expressed as $/GJ of DNC) achieves this objective; and
- Ensure geographic consistency so that users further from sources of gas pay more than those located closer to gas sources.

We note that the price stability achieved through this TPM will not necessarily avoid significant changes in the transmission prices that are passed on from Shippers to end-users of gas. Final end-user pricing is determined by Shippers, who will need to consider how changes in transmission prices across their customer base will be reflected in their charges to customers. We will continue to work with Shippers to understand whether changes in our access products or pricing create unintended impacts on end-users of gas.

The revenue per zone was based on data for GY 2017/18 and the GY 2018/19 pricing under the MPOC and VTC. This starting point gave us a reasonable basis to assess the first criterion. We then adjusted unit prices based on geography. In doing so, some revenue was reallocated between zones to manage pricing impacts. We consider the impacts of this reallocation are minor and positive in term of compliance with the Pricing Principles. We have also continued to bring the Kirikiriroa zone prices into line with other zones in the Waikato region with a 9.4% increase.

The difference in pricing between GY 2018/19 and GY 2019/20 is shown in the following table. These price comparisons should be treated with caution due to the following difficulties in comparing prices across these two years:

- Several large VTC users currently routinely incur significant overrun costs due to the nature of their business. These customers generally have relatively low gas use (and therefore low reserved capacity) but have large increases in load on occasion that lead to substantial overrun charges. Under the GTAC these overruns will not occur as the customers (and their shipper) will nominate DNC on the day of the increased load. Examples of this are the Te Rohe Pōtae-Taupiri and Waikato ki te Tonga Zones, which have large single loads that generated high overruns in previous years. Due to the change in product under the GTAC we do not expect these overruns to be incurred under the GTAC. Accordingly, revenue from these zones has been adjusted downward; and
- There are some contracts that will no longer exist (such as transportation to Frankley Road and Pokuru and other inter-pipeline points) and the distribution of this revenue between the zones is subjective

Changes to Huntly Power Station pricing need to be highlighted. Genesis Energy has an existing VTC Supplementary Agreement that runs through to 2023. As discussed in section 5.4, the economic benefit of this agreement needs to be retained until the end of the contract, however the delivery point of the contract no longer exists under the GTAC. There is also a take or pay obligation under the contract, which provides a minimum revenue stream to First Gas regardless of the actual quantity of gas that flows. To replicate the effects of this Agreement in the GTAC pricing model, we have concentrated the benefits and obligations of this contract to gas flows to Huntly Power Station. This ensures that other users of the system are not impacted by this agreement and the revenue we forecast to generate from each customer is the same between GY 2019 and GY 2020.

This has been put into effect by changes to standard pricing. This means that while the total revenue expected from Genesis' use of the transmission system is the same, year-on-year prices for shipping to Huntly Power Station are not comparable. In our draft TPM we achieved the same result through a supplementary agreement. On reflection we feel that an equalised price between the DNC Fee and the supplementary agreement price is more transparent. This is part of the reason for the large change in DNC Fee between the Draft and Final TPM. A further contributing factor to the change in price has been the move from a forecast load of 22 PJ in the Draft TPM versus 25 PJ in the Final TPM, which has also reduced the DNC Fee for Huntly Power Station.

Assessing price changes will be easier in future years because the access products offered to Shippers will be comparable.

Table 19: GY2019/20 pricing comparison with GY2018/19

Code	Delivery Zone / Individual Delivery Point	DNC	GY2017/18 (Q_{18})	GY2019/20 (Q_{20})	% Change	GY 2018/19 ($P_{19}Q_{18}$)	GY 2019/20 ($P_{20}Q_{20}$)	% Change	GY 2018/19 ($P_{19}Q_{18}$)	GY 2019/20 ($P_{20}Q_{20}$)	% Change
NTHL	Te Tai Tokerau (Northland)	$2.20	333,757	268,693	(19.5%)	$721,126	$605,168	(16.1%)	$2.16	$2.25	4.2%
AUCK	Tāmakimakaurau (Auckland)	$1.93	15,772,044	16,403,213	4.0%	$28,964,550	$31,901,068	10.1%	$1.84	$1.94	5.4%
WKTN	Waikato ki te Raki (Waikato North)	$1.91	1,851,144	2,164,317	16.9%	$3,680,564	$4,303,181	16.9%	$1.99	$1.99	0.0%
HMTN	Kirikiriroa (Hamilton)	$1.37	1,634,566	1,684,009	3.0%	$2,087,577	$2,368,035	13.4%	$1.28	$1.41	10.2%
KING	Te Rohe Pōtae-Taupiri (King Country-Taupiri)	$1.91	693,907	739,578	6.6%	$1,553,918	$1,483,048	(4.6%)	$2.24	$2.01	(10.3%)
WKTS	Waikato ki te Tonga (Waikato South)	$2.02	4,402,764	4,663,448	5.9%	$9,749,816	$9,581,123	(1.7%)	$2.21	$2.05	(7.2%)
TNGA	Tauranga	$2.22	1,093,835	1,100,247	0.6%	$2,308,147	$2,462,144	6.7%	$2.11	$2.24	6.2%
TAPO	Central Plateau	$2.22	1,704,100	1,713,175	0.5%	$3,645,677	$3,862,400	5.9%	$2.14	$2.25	5.1%
WHAK	Whakatane	$2.25	1,204,658	1,351,862	12.2%	$2,759,177	$3,171,814	15.0%	$2.29	$2.35	2.6%
EAST	Te Tai Rawhiti (Eastland)	$2.86	474,641	476,533	0.4%	$1,376,488	$1,397,436	1.5%	$2.90	$2.93	1.0%
TKIE	Taranaki ki Uta (Inland Taranaki)	$0.42	13,124,362	12,535,343	(4.5%)	$5,951,580	$5,300,332	(10.9%)	$0.45	$0.42	(6.7%)
TKIW	Taranaki ki Tai (Coastal Taranaki)	$0.42	17,868	17,067	(4.5%)	$9,689	$7,237	(25.3%)	$0.54	$0.42	(22.2%)
ATEA	Aotea (South Taranaki-Whanganui)	$1.76	1,381,276	1,428,390	3.4%	$2,621,779	$2,614,667	(0.3%)	$1.90	$1.83	(3.7%)
TRUA	Tararua (Manawatu-Horowhenua)	$1.84	2,548,188	2,667,748	4.7%	$4,942,257	$5,062,786	2.4%	$1.94	$1.90	(2.1%)
HWKB	Kahungunu (Hawkes Bay)	$1.91	2,189,248	2,289,125	4.6%	$4,303,393	$4,442,045	3.2%	$1.97	$1.94	(1.5%)
WGTN	Whanganui- a-tara / Kapiti (Kapiti-Wellington)	$2.05	4,075,924	4,164,973	2.2%	$8,524,671	$8,661,298	1.6%	$2.09	$2.08	(0.5%)

BERD	Bertrand Road (Waitara Valley)	$0.12	17,000,000	16,000,000	(5.9%)	$2,642,236	$1,932,800	(26.8%)	$0.16	$0.12	(25.0%)
FAUD	Faull Road	$0.12	12,000,000	14,000,000	16.7%	$852,769	$1,691,200	98.3%	$0.07	$0.12	71.4%
HUPS	Huntly Power Station	$0.37	25,000,000	25,000,000	0.0%	$12,089,491	$9,311,667	(23.0%)	$0.48	$0.37	(22.9%)
MAND	Mangorei Delivery Point	$0.11	n/a	500,000	n/a	n/a	$55,367	n/a	n/a	$0.11	n/a
NGRD	Ngatimaru Rd Delivery	$0.11	43,000,000	44,000,000	2.3%	$4,630,247	$4,872,267	5.2%	$0.11	$0.11	0.0%
	Totals		149,502,283	153,167,721	2.5%	$103,415,151	$105,087,084	1.6%	$0.69	$0.69	(0.8%)

Appendix 1: Regulatory compliance table

Table A demonstrates how this pricing methodology complies with the Gas Transmission Information Disclosure Determination 2012.

Table A: Compliance matrix

Principle	Reference / Description
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 4
(2) Describes any changes in **prices** and **target revenues**;	Sections 4 and 6.1
(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 4.5
(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 5
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.	The pricing methodology will be publicly disclosed by on 30 June 2019, which is 3 months prior to the prices taking effect.
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 4
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**;	Appendix 2.
2.4.3(3) State the **target revenue** expected to be collected for the **pricing year** to which the pricing methodology applies;	Section 2.1
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;	See section 4.2.1.
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 6.1

Principle	Reference / Description
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 4
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 4, Table 3
Effect of Pricing Strategy 2.4.4 Every disclosure under clause 2.4.1 above must, if the **GTB** 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 does not have a pricing strategy for prices set under the GTAC. First Gas intends to consult on a pricing strategy in 2020 in preparation for the TPM for GY 2022.
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- (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**; (b) how the **GTB** determines whether to use a **non-standard contract**, including any criteria used; (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 4.5
(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**.	Section 4.5.3

Appendix 2: Alignment with pricing principles

Regulatory requirement

The ID Determination states that First Gas must:

> 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**;*

Consistency with Pricing Principles

The Commerce Commission has determined pricing principles for regulated gas pipeline businesses. Our evaluation of the consistency between First Gas' TPM and the pricing principles is set out in Tables B (standard pricing) and C (non-standard pricing) below.

Table B: Compliance of standard pricing with the Pricing Principles

Pricing principles	Pricing methodology consistency
(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; (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.	We consider that GTAC prices signal the economic costs of service provision because DNC fees increase as transport extends from Taranaki and more of the transmission network is used. The DNC fees specified in this TPM will likely fall within the range of incremental cost (which is very low) and standalone cost (which is much higher). Previous TPMs formally assessed prices relative to these limits, and since this methodology minimises price changes we have relied to some extent on those earlier assessments. We also can offer non-standard agreements where prices are demonstrated to exceed standalone cost. The ability to signal available capacity and the effect of additional usage on future investment costs is driven primarily by the access products offered under the code, particularly the ability to offer priority rights or call for interruptible load when capacity is scarce. These tools have been developed in the GTAC to provide better price signals in situations when transmission is scarce. This TPM has also set out a process for re-examining the extent to which prices reflect the cost of service at different locations. This work will be completed over the coming year in consultation with stakeholders, and we expect any changes arising from the work to take effect from GY2022.

Pricing principles	Pricing methodology consistency
(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.	The TPM is not fully consistent with this principle. As with principle 1, the terms of the transmission access code have a material impact on consistency with this principle. In the case of the GTAC, the ability to offer non-standard pricing in certain circumstances provides the ability to directly gauge alternative energy supply options that are available to consumers and reflect those in prices. Pricing in this TPM is based on location and the pricing structure defined by the GTAC Code.
(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.	Where bypass or alternative fuels are an economic option, the customer can apply for non-standard prices under the GTAC.
(4) Development of prices is transparent, promotes price stability and certainty for consumers, and changes to prices have regard to the effect on consumers.	We believe development of our prices is transparent and the TPM promotes price stability and certainty for our consumers in the short to medium term.

Table C: 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; b) having regard, to the extent practicable, to the level of available service capacity; and c) signaling to the extent practicable, the effect of additional usage	Prices are subsidy-free There are no capacity constraints currently on the network to be reflected 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.	Prices remain subsidy-free Compliance is enhanced because non-standard pricing ensures that consumers that would otherwise disconnect from the gas transmission system will remain connected and 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
2) Where prices based on 'efficient' incremental costs would under recover allowed revenues, the	If a consumer disconnects because standard prices exceeded their "reservation cost" then those prices	Compliance is enhanced because the demand-responsiveness of a price-sensitive consumer has been

Pricing principle	Extent of compliance without non-standard pricing	Extent of compliance with non-standard pricing
shortfall is made up by prices being set in a manner that has regard to consumers' demand responsiveness, to the extent practicable.	did not reflect the demand-responsiveness of that consumer.	taken into account by the nonstandard 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 nonstandard 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. This 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 consumers whose circumstances make them particularly sensitive to prices.

Appendix 3: Director certificate

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

Clause 2.9.2

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; and

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
Philippa Jane Dunphy	Euan Richard Krogh
28 June 2019	28 June 2019
Date	Date