Pricing Methodology for Gas Transmission Services

From 1 October 2022

Pursuant to the *Gas Transmission Information Disclosure Determination 2012*

First Gas Limited
August 2022

Introduction

First Gas Limited (Firstgas) operates 2,500 kilometres of gas transmission pipelines and more than 4,900 kilometres of gas distribution pipelines across the North Island. These gas infrastructure assets transport natural 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. Our distribution network services approximately 66,000 consumers across the regions of Northland, Waikato, Central Plateau, Bay of Plenty, Gisborne, and Kapiti Coast.

Firstgas is part of the wider Firstgas Group. Firstgas Group owns energy infrastructure assets across New Zealand through Firstgas and Gas Services NZ Midco Limited (GSNZ Midco), a separate business with common shareholders that owns the Ahuroa gas storage facility and Rockgas Limited (Rockgas). Under its gas services brand, GSNZ Midco provides operational and maintenance support to gas infrastructure owners, including other parts of the Firstgas Group.

The Ahuroa gas storage facility (trading as Flexgas) is New Zealand's only underground gas storage facility. Rockgas has over 80 years' experience providing LPG to over 100,000 customers throughout New Zealand. Rockgas is New Zealand's largest LPG retail business and supplies its customers with LPG from both domestic and imported services.

Firstgas is committed to helping Aotearoa achieve its climate change goal of zero carbon emissions by 2050.For more information, visit our website: www.gasischanging.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 2022 to 30 September 2023 (gas year 2023, GY2023).

A signed director certificate is provided with this Pricing Methodology.

This Pricing Methodology was prepared and approved on 29 July 2022.

Further information

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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.
Connection Point (CP):	An aggregation of one or more Delivery Points (DPs) for cost allocation purposes.
Commission:	The Commerce Commission who is charged with monitoring compliance with the *Commerce Act 1986*, including price-quality regulation and information disclosure requirements for regulated businesses.
CPI:	Consumer Price Index.
CRF:	Capacity Reservation Fee, a charge applied for each GJ of reserved capacity under the Gas Transmission Code (GTC)
Delivery Point (DP):	A facility (including any associated land and equipment) at which one or more Shippers are able to take Gas from the Transmission System.
DPP	Default Price-Quality Path
Forecast Allowable Revenue	The revenue Firstgas is allowed to earn during the pricing year under the *Default Price-Quality Path (PQ) Determination*.
GJ:	Gigajoule, a unit of energy.
GTB:	The Gas Transmission Business owned by Firstgas.
ID Determination:	*Gas Transmission Information Disclosure Determination 2012*, consolidating all amendments as of 3 April 2018, published by the Commerce Commission.
GTC	Gas Transmission Code.
GY2023:	Gas year from 1 October 2022 to 30 September 2023.
Incremental cost:	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:	*Gas Transmission Services Input Methodologies Determination 2012* consolidating all amendments as of 3 April 2018, published by the Commerce Commission.
Maximum Flow:	The peak flow rate or capacity of a transmission asset (e.g., pipeline or DP) or connection point.
MPOC:	Maui Pipeline Operating Code.
OATIS	The technology platform supporting operations under the MPOC and GTC.

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
PQ Determination:	*Gas Transmission Services Default Price-Quality Path Determination 2022,* NZCC20, 31 May 2022.
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 Region:	A group of Delivery Points with the same CRF (as set out in section 3.2).
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 Point (RP):	A facility (including any associated land and equipment) at which a producer injects Gas into the Transmission System.
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 Firstgas.
Stand alone cost:	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 2.1 of this document.
TOU:	Time of Use.
TPM:	Transmission Pricing Methodology.
Transmission System:	The entirety of Firstgas' Maui and Non-Maui gas transmission pipelines

Background documents

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

All prices are set to comply with the revenue path set in the PQ Determination for gas transmission. Further details are set out in the *Ex-ante price-setting compliance statement* for the year commencing 1 October 2022 that is also available on the Regulatory page of the Firstgas website.

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1 Overview of Firstgas' transmission system

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

1.1 Firstgas 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 299 kilometres from the Oaonui Production Station in South Taranaki to the Huntly Power Station in the North Island and was purchased by Firstgas 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 GY2021, the Maui Pipeline carried 124 PJ of gas from seven production stations that are directly connected to the pipeline. More than half of that gas goes to two consumers – the Huntly Power Station and the two methanol plants at Motunui owned by Methanex.

Firstgas also owns other gas transmission pipelines (referred to as the Non-Maui gas transmission system) that are directly connected to the Maui pipeline at 14 interconnection points. This 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 Firstgas in April 2016. Gas is taken from this transmission system and delivered to 139 Delivery Points (DPs) owned by Firstgas. These DPs supply both distribution networks and large, directly connected gas consumers such as industrial plants and power stations.

1.2 Industry context for gas transmission pricing

The shared use of a substantial 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 transmission service to a specific connection. Decisions must be made to determine appropriate cost allocation methods.

Firstgas contracts with Shippers to transport their gas from sources of supply (Receipt Points) through the transmission system to Delivery Points. At present, there are 13 Shippers. Seven of these Shippers operate as gas retailers, although some also ship gas to their own gas-consuming facilities. A party becomes a Shipper by agreeing to the terms of a Transmission Services Agreement (TSA), on the Maui pipeline, non-Maui system or both.

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

1.3 Regulatory environment for gas transmission

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

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

From 1 October 2022 to 30 September 2026, the gas transmission system is subject to the revenue cap specified in the *Gas Transmission Services Default Price-Quality Path Determination 2022*

(PQ Determination). The allowable revenue that Firstgas 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 for setting the PQ Determination need to comply with the definitions and approach set out in the Input Methodologies (IMs) developed by the Commerce Commission in 2010 and last amended in May 2022.

The *Gas Transmission Information Disclosure Determination 2012* (ID Determination) sets out several requirements around transmission pricing, including that we publish a transmission pricing methodology and explain the extent to which 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 Approach to pricing methodologies for GY2023

For the pricing year commencing 1 October 2023, Firstgas has adjusted existing MPOC prices for the Maui transmission systema and GTC prices for the Non-Maui gas transmission system to reflect changes in allowable revenue, forecast transmission quantities, pass-through and recoverable costs.

Adjustment to pricing structure

In setting prices for FY2023, Firstgas consulted with stakeholders again about their preferences for pricing structure, specifically the proportion of revenue that would be provided from the variable components of pricing. Only two submissions addressed this point. One favoured a fully variable pricing structure, stating that, in the absence of capacity constraints, the overrun fees associated with capacity reservations are unnecessarily punitive. This stakeholder favoured increasing the variable component of our tariffs as much as possible. The other submission favoured a uniform increase in prices (across both the fixed and variable components) as a means of minimising price shocks to customers. That submitter felt that the large increase in the GTC throughput fee that would accompany a 5% decrease in GTC capacity reservation fees would be disruptive to the gas market.

While both submissions made valid points, we are particularly sensitive to Shippers' concerns about the effect of price changes on their customers. We have therefore adjusted MPOC prices and GTC prices by a similar percentage.

Another point raised in submissions related to the capacity reservation fee for Greater Hamilton, which has been much lower than the capacity reservation fee of other delivery points in the region due to legacy pricing put in place prior to Firstgas ownership. Firstgas had been escalating the fee for Greater Hamilton each year at a relatively moderate rate. In the provisional prices, we proposed aligning the Greater Hamilton fee with the capacity reservation fee applicable to nearby delivery points. Two submitters felt that the magnitude of this increase would constitute too much of a price shock to consumers. One of the submitters suggested a two-year alignment path. After consideration, Firstgas has settled on a three-year path. The capacity reservation fee for Greater Hamilton for FY2023 will therefore be increased by 38% over its FY2022 fee.

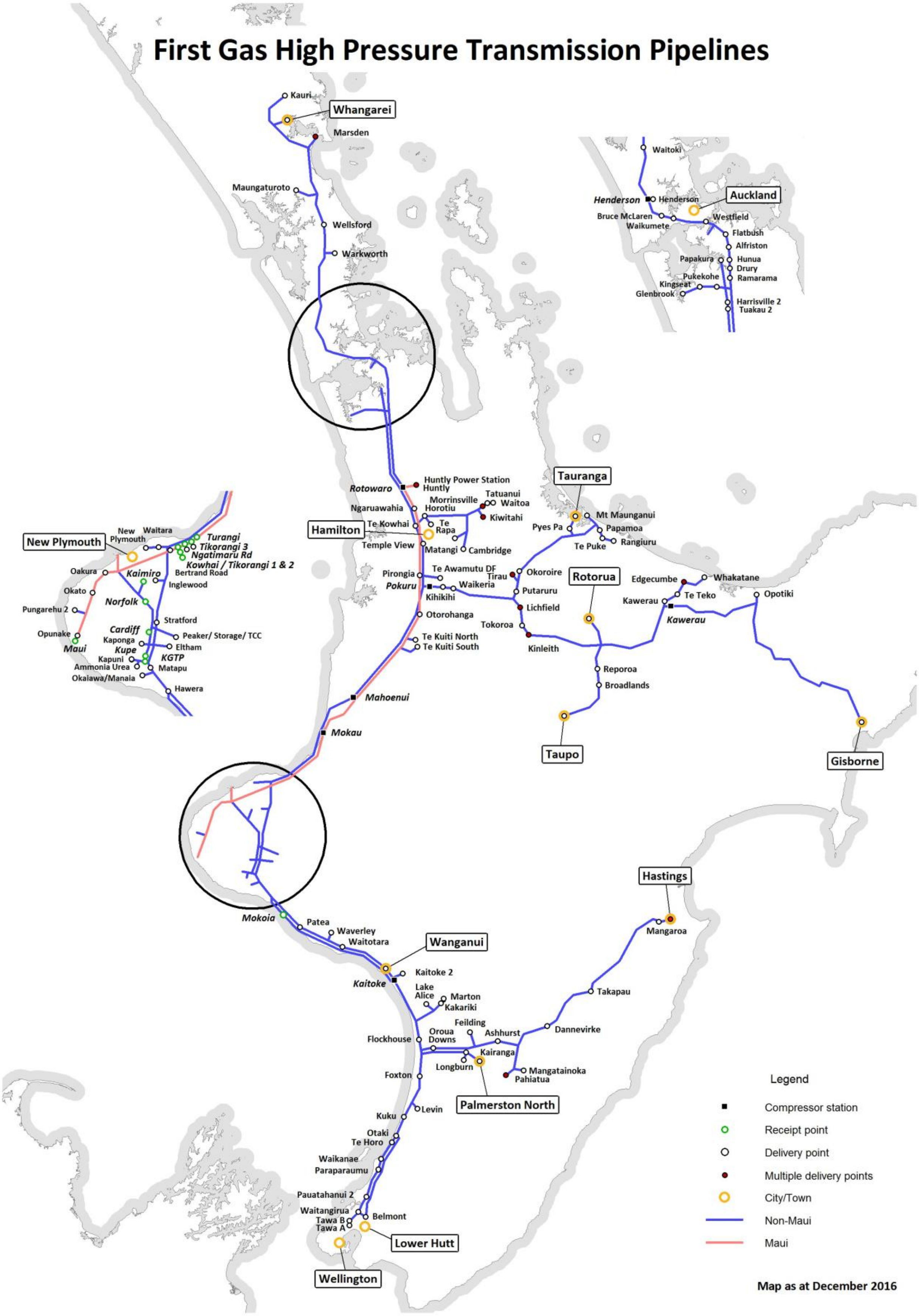
Consolidation into a single disclosure document

The MPOC and GTC pricing methodologies are both presented in this document. This reflects the fact that the regulatory control under the current PQ Determination applies to the GTB as a whole (Maui and non-Maui), and we are required to demonstrate that our prices for GY2023 comply with the single revenue cap.

1.5 Review of transmission pricing methodology during GY2023

Considering the challenges and opportunities facing the gas sector, Firstgas believes it is timely to review our pricing methodology. The Gas Transmission Services Default Price-Quality Path Determination 2022 represents a significant change in approach to setting Firstgas' allowable revenue, and we want to ensure that our pricing methodology remains as equitable and efficient as possible. We also want to ensure that our pricing can adapt to future scenarios, such as distributed gas production through the injection of renewable gases like biomethane and hydrogen. We anticipate that this review could lead to a new pricing methodology that will take effect from GY2024.

Figure 1: Map of Firstgas transmission network



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

The GTB is required to set our prices to recover an amount no greater than the Forecast Allowable Revenue (FAR) under the current PQ Determination (2022 – 2026). Compliance with the FAR requirement is determined by ensuring the GY2023 prices multiplied by the forecast GY2023 quantities (the Target Revenue) is less than or equal to the FAR.

Target Revenue for GY2023 and our compliance with the FAR is set out in Table 1 below.

Table 1: Determining Target Revenue for GY2023 and compliance with the DPP

	Amount ($)	Proportion of target revenue (%)
Forecast allowable revenue (FAR)		
Forecast Net Allowable Revenue	$147,227,000	
Pass-through and recoverable costs / opening balance of wash-up account	$9,540,629	
Forecast Allowable Revenue GY2023	$156,767,629	
Target Revenue		
Standard MPOC revenue	$45,441,436	29.0%
Standard GTC revenue	$99,931,235	63.8%
Non-standard pricing (SA and ICA revenue)	$11,364,441	7.3%
Target Revenue GY2023	**$156,737,112**	**100.0%**
Compliance (Target Revenue ≤ FAR)	Compliant	

Further detail on our compliance with the revenue cap can be found in our FY2023 *ex-ante* price setting compliance statement on our website.[1]

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

Table 2: Key components of target revenue

Cost component	Amount ($000)
Operational expenditure	$59,888,786
Pass through and recoverable costs	$9,540,629
Depreciation	$34,953,916
Tax	$11,738,691
Return on capital	$40,615,091
Target Revenue	**$156,737,112**

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

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 2**.

Firstgas 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.[2] In considering how prices should be set, we have applied those principles in the following way:

- Pricing for regions and delivery points should reflect the extent of assets required to provide the service. Therefore, prices at Delivery Points further from Receipt Points should generally be higher
- Shippers should pay more in locations where provision of capacity is more expensive, to signal the value of that capacity
- Pricing at the region and delivery point level should be consistent with existing prices under the GTC 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 1**.

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

3 Pricing methodology

For the year beginning 1 October 2022, we continue to apply the existing pricing structures for the Maui and Non-Maui transmission systems, as set out in the MPOC and the GTC.

As noted in section 2.1 above, our pricing methodology must ensure that prices set under the MPOC and GTC comply with the revenue cap under the PQ Determination. All revenue earned from the use of the gas transmission system – including both standard and non-standard transmission fees, and interconnection fees – are covered by the PQ Determination and included in the target revenue for GY2023.

3.1 Pricing under the MPOC

The revenue for the GTB is determined on a similar basis under the PQ Determination as specified under the MPOC. Ensuring that pricing for all transmission services is within the parameters set by the PQ Determination means we keep to the intent of the MPOC when setting prices for the Maui transmission system.

Section 19.9 of the MPOC requires Firstgas 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…"*

3.1.1 Revenue by price component

Standard Pricing for GY2023 continues to be based on Tariff 1 and Tariff 2. Non-standard prices are not allowed under the MPOC. The tariff principles set out in Schedule 10 of the MPOC state that:

- **Tariff 1** is intended to provide for a return on Maui pipeline assets. This tariff is expressed in $/GJ.km.
- **Tariff 2** is intended to cover Maui operating costs, and is expressed in $/GJ

GJ.km quantities were determined historically by estimating a realistic routing of gas between Receipt Points and Delivery Points, based on:

- Multiplying the delivery quantity for each Receipt Point and Delivery Point by their respective distances from Oaonui. This determined the GJ.km for all gas shipped into and out of the pipeline with reference to the southernmost Receipt Point (originally, the only Receipt Point)
- Deducting the sum of GJ.km for the Receipt Points from the sum of GJ.km for the Delivery Points to get the net sum of GJ.km for all gas shipped on the system
- Inflating the quantity from the efficient routing above by the average % difference between the efficient routing of gas and the actual billed quantity for the last five years.

Whilst we have not completed these calculations again for GY2023, Prices have been increased uniformly for MPOC tariffs (as described in table 3 below) and therefore reflect the above method.

Final prices under the MPOC must be published on OATIS by early August each year (60 days before the prices take effect). Pricing under the MPOC for GY2023 is discussed further in section 5.1, whilst Table 3 illustrates the close alignment between Schedule 10 of the MPOC and the allowable revenue under the PQ Determination.

Appendix 1 provides further information on how we have combined the requirements under the MPOC and the PQ Determination to meet the pricing principles specified by the Commerce Commission.

Table 3: Requirements under the MPOC reflect the PQ Determination

	MPOC (Schedule 10)	Equivalent Approach under the PQ Determination
	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 [and operating costs] as follows	The Commission sets allowable revenue for each year of a four-year regulatory period for our GTB[3]. Allowable revenue for the regulatory period is set on a building blocks basis that includes: • A WACC return on the regulatory asset base (RAB) • A return of capital based on the useful life of asset • An allowance for Operating Expenditure (Opex). Allowable revenue is specified in the PQ Determination.
	Determine Tariff One	**Determine Revenue for the GTB as a single system.** Table 1 shows the expected revenue from prices under the MPOC.
(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")	Allowable revenue for GY2023 is allocated to proposed Tariffs under the MPOC and GTC methodologies. Forecast revenue is the sum of tariffs multiplied with the associated forecast quantities. Tariffs are set such that forecast revenue for the GTB is less than allowable revenue.
(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")	Tariff 1 for GY2023 is based on previous years. (refer section 5.1)
(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	Tariff 1 is applied across the Maui Pipeline Shippers on the basis of quantity of gas (measured in gigajoules) to be transported multiplied by the distance of gigajoules of Gas transported.
	Determine Tariff Two:	**Determine Revenue for the GTB as a single system.** Table 1 shows the expected revenue from prices under the MPOC.
	The approach adopted by TSP to recover operating expenditure is to:	As with Tariff 1 above, an allowance for Opex is included in the allowable revenue set by the Commission. Firstgas ensures that forecast revenue for the GTB is less than allowable revenue.
(a)	Aggregate the Maui pipeline's operating costs (Opex)	
(b)	Allocate operational expenditure across every gigajoule of gas delivered from the Maui Pipeline.	Tariff 2 is applied across Maui Pipeline Shippers on the basis of Gigajoules of gas delivered from the Maui system. Tariff 2 for GY2023 is based on previous years. (refer section 5.1)
	Reduce price volatility	
	In any given year, in the event that the: • TSP's total revenues are more or less than its required revenue then Tariff 1 • TSP's total Operational Expenditure recovery is more or less than its required recovery then Tariff 2 the respective tariffs may be adjusted for the following years in a manner that endeavours to reduce pricing volatility for Shippers.	As noted in section 2.2 above, when setting prices, we maintain consistency with existing prices as much as possible to ensure that any tariff shock is minimised.

[3] Section 53M allows the Commerce Commission to set a default price-quality path for either 4 or 5 years. In 2022 the Commerce Commission set the price-quality path for the third regulatory period for 4 years (1 October 2022 – 30 September 2026)

3.2 Pricing under the GTC

As outlined in section 1.4, Firstgas has sought to adjust GTC prices by a relatively uniform percentage in response to concerns about the effect that price rebalancing would have on consumers.

The GTC also allows for non-standard contracts and pricing as described in section 3.5 below. Revenue and prices are determined for non-standard contracts first so standard prices can be set. This reflects non-standard prices being either ongoing and/or individually negotiated.

GTC standard capacity reservation fees are set on a regional basis. A pricing region may include one or more Transmission Zones[4]. Table 4 lists transmission pricing regions for GY2023 and the Delivery Points which fall within each pricing region.

[4] A Transmission Zone is a group of Delivery Points for which a Shipper's reserved capacity is "pooled".

Table 4: Aggregation of Delivery Points into pricing regions

GY2023 Pricing Regions		Delivery points
1	Taranaki	Ammonia Urea, Eltham, Inglewood, Kaponga, Kapuni (Lactose), 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, Kaimiro (Delivery), Kupe Delivery, KGTP Delivery
2	Waikato South	Otorohanga, Pirongia, Te Awamutu DF, Te Kuiti North, Te Kuiti South,
3	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	Marsden 2, Kauri DF, Maungaturoto DF, Warkworth, Wellsford, Whangarei
5	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	Hawera, Hawera (Nova), Kaitoke, Kakariki, Lake Alice, Manaia, Marton, Matapu, Mokoia (Delivery), Patea, Waitotara, Wanganui, Waverley
7	Manawatu - Horowhenua	Ashhurst, Feilding, Flockhouse, Kairanga, Longburn, Mangatainoka, Oroua Downs, Pahiatua, Pahiatua DF, Palmerston North, Foxton, Kuku, Levin,
8	Hawkes Bay	Dannevirke, Hastings, Hastings (Nova), Mangaroa, Takapau
9	Wellington	Belmont, Greater Waitangirua, Otaki, Greater Kapiti, Pauatahanui 2, Tawa A, Tawa B (Nova), Te Horo
10	Waikato East	Kihikihi, Kinleith, Kinleith (Paper mill), Lichfield DF, Lichfield 2, Okoroire Springs, Putaruru, Tirau, Tirau DF, Tokoroa, Waikeria
11	Bay of Plenty West	Greater Mt Maunganui, Greater Tauranga, Rangiuru, Te Puke, Tauriko
12	Bay of Plenty South	Broadlands, Kawerau, Kawerau (ex-Caxton), Kawerau (ex-Tasman), Reporoa, Rotorua, Taupo,
13	Bay of Plenty East	Edgecumbe, Edgecumbe DF, Te Teko, Whakatane
14	Eastland	Gisborne, Opotiki
15	Hamilton	Greater Hamilton

3.2.1 Standard price setting for the GTC

Standard Price means any price that is published as part of the Confirmed Standard Transmission Fees Schedule published on OATIS.[5] Standard Prices include the prices for the Frankley Road pipeline and the price for transmission from Kapuni to Pokuru.

Further information on pricing for GY2023 is in section 5.2.

GTC revenue by standard price component

Standard revenue under the GTC comes from throughput fees (TPF), capacity reservation fees (CRF) and overrun fees. Around 66% of GTC standard revenue comes from CRFs and a further 24% from TPFs.

- **CRFs** are applied to the annual Capacity (GJ) reservations at a DP (or in respect of a Transmission Zone) and represent a transmission right in terms of maximum daily quantity (MDQ). CRFs are based on the assets employed between the relevant Receipt Point and DP. Capacity reservations are provided by shippers in September prior to the beginning of each gas year on 1 October. A Shipper may transfer reserved capacity between Delivery Points or pipelines, or trade it with another

[5] https://www.oatis.co.nz/Ngc.Oatis.UI.Web.Internet/Common/Publications.aspx> Transmission Fees

Shipper. A Shipper may cancel reserved capacity within a year only to the extent that another Shipper has booked additional reserved capacity within that year.

Final capacity reservations are not known at the time of finalising the TPM and setting confirmed prices for a year, so we it is necessary to forecast capacity reservations based on historical gas flows and observed booking patterns to determine revenue recovered by this fee.

- The **TPF**[6] is applied to the GJ delivered. It is necessary to forecast throughput quantities to determine revenue recovered by this fee.
- **Overrun fees**[7] are forecast as a percentage of total revenue for each pricing zone. This is because the choice shippers make on the level of overruns they plan to incur is an economic decision, based on trading off savings in capacity reservation charges on the one hand against overrun charges on the other. The percentage of overrun charges relative to throughput and capacity charges for each pricing zone is generally taken to be the average for the previous three years.

Under the GTC, final prices (CRFs and the TPF) must be notified to customers by 1 September each year.

3.3 Determining the Target Revenue for the GTB

To show how we determine our target revenue each pricing year, Table 5 sets out the components that factor into our pricing methodology and prices for the GTB. The overall pricing methodology and pricing of transmission services by Firstgas brings together pricing under the MPOC and GTC.

Table 5: Components for inclusion in pricing methodology

Forecast Revenue from Prices	≤	Forecast Allowable Revenue
This equals the:		This equals the:
Sum of each standard price under the MPOC multiplied by each corresponding forecast quantity for the Maui transmission network		Forecast net allowable revenue
+ Sum of each standard price under the GTC multiplied by each corresponding forecast quantity for the Non-Maui transmission network		+ Forecast pass-through and recoverable costs that includes: • Rates and levies • Balancing gas costs and revenues • Mokau compressor fuel gas costs • Capex Wash-up adjustment
+ Non-Standard Pricing including ICA revenue and SA revenue		+ Opening balance of the wash-up account
This is our **Target Revenue** for the pricing year.		This is our **Forecast Allowable Revenue** for the pricing year.

[6] Historically, the same TPF has been applied to all Delivery Points other than those on the Frankley Road pipeline.

[7] Overrun fees are an incentive fee to encourage reasonable capacity booking. The standard overrun fee is ten times the CRF calculated on a daily basis and applied to GJ delivered in excessive of reserved capacity.

Our Transmission Pricing Model calculates the Target Revenue while 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 PQ Determination. This is considered the total allowable revenue
2. We calculate revenue from non-standard agreements (SAs) as shown in the table below. This is estimated using throughput forecasts together with any changes to capacity and/or prices in accordance with the agreements
3. The forecast revenue from SAs and also interconnection agreements (ICAs) is deducted from the total allowable revenue to establish the required standard revenue
4. The Target Revenue is calculated.

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

Table 6: Target revenue compliance with forecast allowable revenue

Revenue component	Amount	
Forecast Allowable Revenue (A)	$156,767,629	
Target Revenue ($)		**Proportion of Target Revenue (%)**
Non-Standard Pricing		
• GTC ICA Revenue (B)	$1,185,044	0.8%
• GTC SA Revenue (C)	$10,179,397	6.5%
Standard Pricing		
• MPOC standard revenue (D)	$45,441,436	29.0%
• GTC standard revenue (E)	$99,931,235	63.8%
Target Revenue (F = B + C + D + E)	**$156,737,112**	**100.0%**
Difference (A – F)	30,516	
Compliant?	**YES**	

3.4 Transmission pricing assumptions

3.4.1 Forecast gas flows

Each year Firstgas is required to forecast throughput for the coming year starting 1 October. Our forecast is based on a third- party forecast of gas flows across the network (completed by Aretê Consulting Limited), peer reviewed by Firstgas staff. The resulting outcome reflects both statistical methods as well as market intelligence such as expected changes to existing loads.

Forecast throughput at Delivery Points include delivered quantities under both standard and non-standard contracts.

For non-standard contracts that will continue in GY2023, capacity quantities will be maintained the same unless varied in accordance with the contract or in agreement with the relevant Shipper.

3.4.2 Forecast capacity bookings

Capacity reservations have been estimated based on historical gas flows and observed booking patterns. Shippers generally reserve less capacity than their annual peak MDQ, to optimise capacity reservation fees versus overrun charges. One GJ of reserved capacity attracts 365 days of charges, whereas one GJ of overrun is charged the equivalent of 10 days of charges. Shippers will also take advantage of seasonal (counter-cyclical) demand if they can and use the ability to transfer reserved capacity to minimise their overall capacity bookings. Shippers tend to book capacity at a level that represents about the 37th highest day in the previous gas year.

For GY2023, Firstgas used this observed relationship between historical gas flows and capacity bookings to project bookings for the coming year. Adjustments have been made where required to account for the expiration of supplementary agreements, where the load will be charged standard prices in the coming year.

3.5 Approach to prices and revenue for non-standard contracts

In certain circumstances, the published standard prices may not adequately reflect:

- the actual costs of supplying a consumer or the economic value of the service to the consumer
- the commercial risks associated with supplying that consumer
- recognise the consumer's circumstances (including the availability of an alternative fuel).

In such cases, non-standard contracts may be more appropriate for customers.

3.5.1 Extent of non-standard contracts

In addition to standard published prices, our transmission pricing methodology also covers the following non-standard transmission agreements:

- **Supplementary Agreements (SAs)**: A bi-lateral agreement between Firstgas and a Shipper that amends parts of the GTC and provides firm transmission capacity for the purposes of delivery of gas to a specific DP and consumer
- **Interruptible User Contracts (IUC)**: A form of supplementary agreement that allows the Shipper to request a maximum daily quantity (MDQ) on an interruptible basis to supply a specific consumer
- **Interruptible Shipper Contracts (ISC)**: A form of supplementary agreement that allows the Shipper to request a MDQ on an interruptible basis. Capacity approved by Firstgas may be used only to ship gas from one part of the Non-Maui pipeline to another, or between Non-Maui pipelines.

These contracts apply only to the Non-Maui transmission system.[8] Non-standard contracts are not allowed under the MPOC.

Under an SA, IUC or ISC the Shipper is charged the non-standard transmission fees specified in the agreement. Such non-standard agreements are subject to the Firstgas Supplementary Agreements Policy[9]. There are 13 supplementary or interruptible contracts. Collectively their charges represent around 6.3% of target revenue for GY2023.

Prices in non-standard contracts are set as specified in the contract, in a separate Transmission Pricing Agreement (TPA) or are redetermined annually by Firstgas. Annual contracts that we will again offer have had their current prices increased by the weighted average Consumer Price Index (CPI) movement to March 2022, though some of prices will be subject to specific review before prices are finalised.

[8] Further information on our non-standard contracts is available on the Firstgas website. https://firstgas.co.nz/wp-content/uploads/2018-19-Transmission-Non-Standard-Contract-Disclosure.pdf

[9] https://www.oatis.co.nz/Ngc.Oatis.UI.Web.Internet/Common/Publications.aspx > supplementary agreements

Interconnection agreements

We also offer an interconnection agreement (ICA) that allows a party to physically connect to a (Non-Maui) pipeline to either inject gas (Receipt Point) or take gas (Delivery Point). ICAs are not part of the GTC, although they reference several GTC provisions.

Interconnection fees are charged in circumstances where Firstgas has built or upgraded a delivery point or other transmission infrastructure to enable the connection. These fees are specified in the ICA and are subject to the Firstgas Interconnection Policy. Interconnection fees are a daily charge to recover the cost of the connection. There are currently 22 ICAs, and interconnection fees represent around 0.8% of target revenue for GY2023.

Forecast revenue from non-standard contracts

Forecast revenue for non-standard contracts is about $10.2 million, representing 6.5% of our target revenue.

3.5.2 Criteria for non-standard contracts

Any Shipper on the Non-Maui transmission system may request a Supplementary Agreement if it believes that the standard provisions of the GTC are not appropriate in relation to the transmission (or potential transmission) of its Gas for supply to a specific end-user or site.

Information on factors to be considered when deciding whether or not to offer a non-standard contract on the transmission system is available under the *Supplementary Agreements Policy* (2020) available on OATIS.

3.5.3 Methodology for non-standard prices

The prices in each non-standard contract are set to reflect the circumstances of the specific Shipper/end-user (or interconnected party, in the case of an ICA). In all cases, prices are tested to ensure they are not less than incremental cost of supply or greater than standalone costs.

When a non-standard contract is due for renewal, pricing is re-assessed to determine whether circumstances still justify non-standard prices or (where relevant) the extent of any discount to standard prices. The flexible approach to pricing for non-standard contracts achieves greater alignment with the Pricing Principles, as demonstrated in **Appendix 1**.

3.5.4 Obligations around service interruptions

The ID Determination[10] requires Firstgas 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) TSAs and SAs (excluding interruptible agreements) are comparable.

Reserved capacity provided under Shippers' TSAs ranks equally with firm capacity provided under SAs (supplementary capacity) in the event of an emergency or other event affecting the relevant part(s) of the transmission system.

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

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

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 of the fixed transmission fees.

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

3.6 Forecasting balancing and pass-through costs

As explained in section 2.1 (above), Forecast Allowable Revenue includes amounts defined in the Input Methodologies as pass-through and recoverable costs. Five different types of such costs are aggregated when setting transmission prices for a year. These are specified in section 3.1.2 or 3.1.3 of the Input Methodologies and summarised in the sections below.

Table 7: Forecast values for rates and levies for GY2023

Pass-through cost	Amount
Rates and levies	$3,303,888
Balancing gas costs and revenues	$2,065,290
Mokau fuel gas	$1,602,300
Capex wash-up adjustment	$0
Opening balance of wash-up account (revenue cap mechanism)	$2,569,151
Total pass through and recoverable costs	**$9,540,629**

3.6.1 Rates and levies

The following costs are included in this category:

- **Property rates** from GY2022 were used as a basis. It has been assumed that there will be an increase in property rates largely in line with an inflation adjustment (CPI).
- **Commerce Act levies** are similar to GY2022 and reflect the Commerce Commission's forecast for its 'bridging the gap' levy funding.[11] This includes the upcoming Input Methodologies review..
- **Utilities Disputes** are determined annually as prescribed by the scheme rules. The levies do not significantly change year on year. For GY2023 it is assumed the levies will remain the same as those changed in April 2022.

The forecast values for GY2023 are shown in Table 8.

Table 8: Forecast values for rates and levies

Pass-through cost	Amount
Rates	$1,631,000
Commerce Commission levies	$1,637,786
Utility Disputes Limited Levies	$35,102
Total	**$3,303,888**

3.6.2 Balancing gas costs and revenues

Balancing gas costs were projected based on the volumes of gas transacted in previous years. To estimate the average buy / sell price for the coming year, Firstgas took the midpoint of the implied forward price range. This has been derived from electricity price futures, which in contrast to previous years is much higher. Firstgas has also incorporated a market discount and premiums for when gas must be sold and bought – Firstgas are price takers, and pipeline conditions are public information.

The total costs are shown in the Table 9.

[11] https://comcom.govt.nz/__data/assets/pdf_file/0024/229830/Part-4-energy-levy-funding-consultation-paper-10-Dec-2020.pdf

Table 9: Forecast balancing costs and revenues

Balancing gas costs	Average Volume GY2018 - GY2020 (GJ)	Forecast volume GY2022 (GJ)	Firstgas average price ($/GJ)	Amount ($)
Total gas bought	393,830	393,000	$22.25	$8,744,250.00
Total gas sold	720,103	720,000	$(9.40)	$(6,768,000.00)
Total bought and sold		1,113,000		
Trading costs			$0.08	$89,040.00
Total costs				**$2,065,290**

Firstgas notes the degree of uncertainty around forecasts for balancing gas costs and revenues, driven by two volume-related factors:

- It is impossible to exactly anticipate how much gas will need to be transacted (either buying or selling) to keep the system in balance.
- We do not know the prices that will apply to those balancing gas transactions, since pricing is very responsive to market dynamics at the time the transactions (each an operational response) occur.

3.6.3 Mokau compressor fuel gas costs

Mokau compression is treated as a recoverable cost under the Input Methodologies. Mokau fuel gas costs were calculated by using average volumes from previous years, which have remained consistent. We have taken the midpoint of the implied forward price range for fuel gas. We have also incorporated a market premium for when we must buy gas – we are price takers, and pipeline conditions are public knowledge. The resulting forecast cost is **$1,602,300.**

3.6.4 Capex wash-up adjustment

The Capex wash-up adjustment is a recoverable cost that can be added to prices for years 2 – 4 of the DPP3 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.

GY2023 is the first year of the DPP3 regulatory period. As such, the value for GY2023 is **$0**.

3.6.5 Revenue cap wash-up

The revenue cap wash-up amount is calculated and published as part of Firstgas' PQ Compliance Statement (issued within 50 days of the end of the pricing year).[12] A time value of money adjustment as prescribed in the PQ Determination is applied to the calculated raw amount. The value for GY2023 is **$2,569,151.**

[12] First Gas' compliance statements for our gas transmission business are available on our website here: https://firstgas.co.nz/about-us/regulatory/transmission/. From FY2023, the end of year PQ Compliance Statement will be issued by 31 March of the following year in line with the publication of our annual information disclosure.

3.7 Pricing for subsequent years

3.7.1 Loss of a significant load

The future impact on prices of losing a major load varies depending on the location of the load on the system. For example, the loss of a load on the Maui pipeline will have a much lower pricing impact than the loss of the same size load in (for example) Northland. This simply reflects the difference in assets employed and the higher prices prevailing even before the load was lost.

We face at least two options when a large load is lost:

- Confine revenue collection to the region in which the load was lost, and increase prices only there to compensate or
- Spread the lost revenue over the entire system.

In the first case, Firstgas would be required to collect the same revenue from a smaller volume of load in the same zone. The remaining load might not be able to support the resulting increase in prices (consumers might disconnect). It could also create undesirable price differences between adjacent regions.

In the second case, spreading the loss over the system could have the effect of some transmission customers bearing costs for assets that they do not use.

Therefore, a degree of judgement is required in determining how to adjust prices in such situations. An important factor to consider is how the previous revenue was shared before the load was lost.

3.7.2 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. In 2013, Vector Gas Limited demonstrated the range of transmission prices between standalone cost and incremental in its TPM based on work undertaken by Price Waterhouse Coopers (PWC). A summary of the PWC study is provided in our GY2018 Transmission Pricing Methodology available on our website.[13]

Given the very high standalone costs and low incremental cost of service, we did not seek to demonstrate pricing compliance within this range. Moreover, since we have continued pricing under the GTC and MPOC, the previous assumptions hold.

We are considering this principle during our upcoming review of the Transmission Pricing Methodology.

[13] See page 36, https://firstgas.co.nz/wp-content/uploads/First-Gas-GTB-pricing-methodology-PY2019.pdf .

4 Consultation with stakeholders

Consultation this year has focused on the pricing methodologies that will apply for GY2023 including:

- Optionality around the proportion of revenue received from variable prices
- The allocation of increased forecast allowable revenue compared to GY2022 across prices.

4.1 Consultation on provisional prices

We provided provisional prices to customers on 1 June 2022 outlining the proposed price increase and information on the proposed structure of pricing.

Firstgas received correspondence from five interested stakeholders. After reviewing the feedback, we considered our approach for GY2023 pricing was appropriate.

5 Final prices for GY2023

This section sets outs the final standard prices for GY2023 that have been determined under the MPOC and GTC.

The revenue earned from transmission services provided under the MPOC and GTC has been updated to reflect changes in allowable revenue, forecast transmission quantities, and pass-through and recoverable costs. For GY2023, we have increased prices under the GTC, and increased MPOC tariffs by roughly the same proportion.

The proportion of target revenue that is collected through each contract for GY2023 is summarised in Table 10 below.

Table 10: Proportion of target revenue by price component for GY2023

	Amount ($)	Proportion of target revenue (%)
Standard MPOC revenue		
Tariff 1	$31,259,751	
Tariff 2	$14,181,685	
Standard Target revenue under MPOC	**$45,441,436**	$45,441,436
Standard GTC revenue		
Capacity Reservation Fees (CRF)	$66,569,780	42.5%
Throughput Fees (TPF)	$27,890,420	17.8%
Over-run Fees	$5,471,036	3.5%
Target standard GTC revenue	$100,256,880	63.8%
Total standard target revenue	**$145,698,316**	**92.7%**
Non-standard GTC target revenue	$11,066,582	7.3%
Total target revenue	**$156,764,898**	**100.0%**

The change in standard prices for GY2022 under the MPOC and GTC are outlined below.

5.1 MPOC prices for GY2023

MPOC pricing for GY2023 is 11.5% higher than pricing for GY2022. This increase in pricing reflects the increase in forecast allowable revenue this year.

MPOC pricing for GY2022 is set out in Table 11 below.

Table 11: GY2023 MPOC prices

Tariff	Unit	GY2022	GY2023	Percentage change
Tariff 1	$ / GJ.km	0.001832	0.002043	11.5%
Tariff 2	$ / GJ	0.083663	0.093284	11.5%

5.2 GTC prices for GY2023

Standard pricing for GY2023 largely reflects proportionality in the current period by region and price component. We continue to align price increases under the MPOC and GTC and continue to move the CFR for the Hamilton region closer to the CFR for other regions.

Specific actions for GY2023 pricing year include:

- An increase in the CRF for the Hamilton from $191/GJ.MDQ to $264/GJ.MDQ. The CFR is based on the distance of supply from where the gas is injected in Taranaki. For GY2023, we have increased the CFR rate by 38%.
- An increase in the CRF for all other regions by up to 12.7% . The increase in GY2023 aligns price increases between the MPOC and GTC, and largely reflects an increase in forecast allowable revenue this year.
- The TPF for all pricing regions has increased from $0.34 to $0.39.
- Table 12 summarises the changes in price between GY2022 and GY2023 and Table 13 summarises the standard revenue by pricing region under the GTC for GY2023.

Table 12: GY2023 GTC standard prices

Pricing Region	GY2022		GY2023		Percentage change	
	TPF $/GJ	CRF $/GJ.MDQ	TPF $/GJ	CRF $/GJ.MDQ	TPF %	CRF %
Taranaki	$0.34	$82	$0.39	$92	14.7%	12.7%
Waikato South	$0.34	$359	$0.39	$404	14.7%	12.7%
Auckland	$0.34	$349	$0.39	$393	14.7%	12.7%
Northland	$0.34	$530	$0.39	$597	14.7%	12.7%
Waikato North	$0.34	$359	$0.39	$404	14.7%	12.7%
South Taranaki - Whanganui	$0.34	$339	$0.39	$382	14.7%	12.7%
Manawatu – Horowhenua	$0.34	$349	$0.39	$393	14.7%	12.7%
Hawke's Bay	$0.34	$359	$0.39	$404	14.7%	12.7%
Kapiti - Wellington	$0.34	$431	$0.39	$486	14.7%	12.7%
Waikato East	$0.34	$359	$0.39	$404	14.7%	12.7%
Bay of Plenty West	$0.34	$441	$0.39	$497	14.7%	12.7%
Bay of Plenty South	$0.34	$462	$0.39	$520	14.7%	12.7%
Bay of Plenty East	$0.34	$482	$0.39	$543	14.7%	12.7%
Eastland	$0.34	$503	$0.39	$567	14.7%	12.7%
Hamilton	$0.34	$191	$0.39	$264	14.7%	12.7%
Frankley Road	$0.34	n/a	$0.39	n/a	14.7%	n/a

Table 13: GY2023 GTC standard forecast revenue

	Prices		Quantities	Revenue($)			Total Revenue
Pricing Region	**TPF ($/GJ)**	**CRF ($/GJ.MDQ)**	**Throughput**	**TPF**	**CRF**	**Over-Run**	
Taranaki	$0.39	$92	1,769,814	$690,227	$423,520	$100,369	$1,214,117
Waikato South	$0.39	$404	4,144,997	$1,616,549	$7,595,472	$919,360	$10,131,381
Auckland	$0.39	$393	15,662,738	$6,108,468	$23,103,240	$1,127,572	$30,339,280
Northland	$0.39	$597	55,847	$21,780	$374,597	$46,733	$443,110
Waikato North	$0.39	$404	2,260,426	$1,067,356	$4,155,819	$226,452	$5,449,626
South Taranaki - Whanganui	$0.39	$382	1,676,786	$653,947	$2,648,408	$144,313	$3,446,667
Manawatu - Horowhenua	$0.39	$393	2,301,835	$897,716	$3,779,750	$432,198	$5,109,664
Hawkes Bay	$0.39	$404	1,984,653	$774,015	$3,016,363	$350,989	$4,141,367
Kapiti - Wellington	$0.39	$486	4,150,654	$1,618,755	$8,948,626	$812,632	$11,380,012
Waikato East	$0.39	$404	19,206	$7,490	$1,402,740	$135,100	$1,545,330
Bay of Plenty West	$0.39	$497	1,168,879	$455,863	$2,453,873	$265,950	$3,175,685
Bay of Plenty South	$0.39	$520	1,763,856	$687,904	$3,568,042	$501,776	$4,757,722
Bay of Plenty East	$0.39	$543	1,191,091	$464,525	$2,319,112	$99,654	$2,883,292
Eastland	$0.39	$567	372,414	$145,241	$902,759	$185,810	$1,233,811
Hamilton	$0.39	$264	1,656,055	$645,861	$1,877,459	$122,129	$2,645,449
Frankley Road	$0.39	n/a	30,858,262	$12,034,722	n/a	n/a	$12,034,722
Total Standard Revenue (GTC)				**$27,890,420**	**$66,569,780**	**$5,471,036**	**$99,931,235**

Appendix 1: Consistency with pricing principles

Regulatory requirement

The ID Determination states that Firstgas 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 Firstgas' TPM based on the MPOC and GTC pricing methodologies, and the pricing principles is set out in Tables A (standard pricing) and B (non-standard pricing) below. Non-standard pricing applies to the GTC only.

Table A: Consistency of standard pricing with the Pricing Principles

Pricing principles	Pricing methodology consistency	
	MPOC	GTC
(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 TPM 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.	Pricing under the GTC is not fully consistent with this principle. The GTC methodology inherited from Vector considered incremental and standalone costs. In GY2023 we have continued to adjust regional capacity prices and have increased prices for capacity reservations in the Hamilton region. 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.
(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 the same for all our consumers and does not consider demand responsiveness	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 GTC, the ability to offer non-standard pricing provides the ability to directly respond to individual circumstances, so as to retain load that might otherwise be lost, withy detrimental impact for remaining consumers' prices. Pricing in this TPM is based on location and the pricing structure inherited under previous versions of the TPM.

Pricing principles	**Pricing methodology consistency**	
	MPOC	**GTC**
(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 TPM 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.	Where bypass or alternative fuels are an economic option, the customer can apply for non-standard prices under the GTC.
(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. In setting prices for this year, Firstgas has reflected the value of maintaining price increases relatively consistent across the networks.	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 B: Consistency of non-standard pricing under the GTC with the Pricing Principles

This table shows how the use of non-standard pricing can allow us to be consistent with the pricing principles. We have compared consistency with the principles without non-standard pricing and then with non-standard pricing.

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.	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 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 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 2: Regulatory compliance table

Table C demonstrates how this pricing methodology complies with the requirements set in the *Gas Transmission Information Disclosure Determination 2012*.

Table C: Compliance matrix

Principle	Reference / description	
	Pricing methodology for MPOC	**Pricing methodology for GTC**
2.4.1 Every **GTB** must **publicly disclose**, before the start of each **pricing year**, a pricing methodology which-	The pricing methodology will be publicly disclosed by 30 September 2022. See individual clauses below	
(1) Describes the methodology, in accordance with clause 2.4.3, used to calculate the **prices** payable or to be payable;	Section 3.1	Section 3.2
(2) Describes any changes in **prices** and **target revenues**;	Section 3.3 explains how target revenues are determined and section 5 describes changes in prices and target revenues	Section 3.3 explains how target revenues are determined and section 5 describes changes in prices and 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	Not applicable. Non-standard contracts are not available under the MPOC	Section 3.5
(4) Explains whether, and if so how, the **GTB** has sought the views of **consumers**, their expectations in terms of **price** and quality, and reflected those views in calculating the **prices** payable or to be payable. If the **GTB** has not sought the views of **consumers**, the reasons for not doing so must be disclosed.	Section 4	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.	The pricing methodology for GY2023 continues to be based on the MPOC and GTC. Our pricing methodology will be publicly disclosed by 30 September 2022.	
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**;	Sections 3.1, 3.3 and 5.1.	Sections 3.2, 3.3 and 5.2.
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 1.	Appendix 1.
2.4.3(3) State the **target revenue** expected to be collected for the **pricing year** to which the pricing methodology applies;	Section 3.3	Section 3.3

Principle	Reference / description	
	Pricing methodology for MPOC	**Pricing methodology for GTC**
• 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 2.1, table 2	Section 2.1, table 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 5.1.	Section 5.2.
Revenue by Consumer Group 2.4.3(6) Where applicable, describe the method used by the **GTB** to allocate the **target revenue** among **consumers**, including the numerical values of the **target revenue** allocated to **consumers** and the rationale for allocating it in this way;	Section 3.3 and section 3.1	Section 3.3 and section 3.2
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 disclose**d under clause 2.4.18.		
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.	Firstgas does currently not have a pricing strategy.	

Principle	Reference / description	
	Pricing methodology for MPOC	Pricing methodology for GTC
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**;	Not applicable. Non-standard contracts are not available under the MPOC.	Section 3.5
(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**.	Not applicable. Non-standard contracts are not available under the MPOC.	Section 3.5

Appendix 3: Director certificate

We, Mark Adrian Ratcliffe and Fiona Ann Oliver, being directors of First Gas Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

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

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

Director: Mark Adrian Ratcliffe	Director: Fiona Ann Oliver
29 July 2022	29 July 2022
Date	Date