Pricing Methodology for Gas Transmission Services

From 1 October 2020

Pursuant to the Gas Transmission Information Disclosure Determination 2012

First Gas Limited
September 2020

Introduction

First Gas Limited (Firstgas) operates 2,500 kilometres of gas transmission pipelines (including the Maui pipeline), and more than 4,800 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 Firstgas, please visit our website www.firstgas.co.nz.

Firstgas is part of the wider Firstgas Group. The Firstgas Group owns energy infrastructure assets across New Zealand through our affiliate Gas Services NZ Limited (GSNZ), a separate business with common shareholders that owns the Rockgas[1] and the Ahuroa gas storage[2] facility. Rockgas has over 80 years' experience and provides LPG to 100,000 customers throughout New Zealand. It is New Zealand's largest LPG retail business and supplies its customers with both domestic and imported sources of LPG. The Ahuroa gas storage facility (trading as Flexgas Limited) is New Zealand's only open access gas storage facility

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 2020 to 30 September 2021 (gas year 2021, GY2021).

A signed director certificate is provided with this Pricing Methodology.

This Pricing Methodology was prepared and approved on 12 August 2020.

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.
Allowable Notional Revenue:	The revenue Firstgas 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.
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 Vector Transmission Code (VTC)
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.
DPP Determination:	*Gas Transmission Services Default Price-Quality Path Determination 2017* consolidating all amendments as of 18 December 2018*,* NZCC23, 18 December 2018.
GJ:	Gigajoule, a unit of energy.
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.
GY2021:	Gas year from 1 October 2020 to 30 September 2021.
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 VTC.

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 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.
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.
VTC	Vector Transmission Code.

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 DPP Determination for gas transmission. Further details are set out in the *ex-ante price-setting compliance statement* for the year commencing 1 October 2020 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 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 310 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 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 GY2019, the Maui Pipeline carried 127 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.

Firstgas 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 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 131 Delivery Points (DPs) owned by Firstgas. 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 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 specific service to a connection. Decisions must inevitably be made in determining appropriate allocation methods.

Firstgas 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 agreeing to the terms of 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, 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; and
- **Information disclosure requirements**, that 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 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 DPP Determination need to apply with the definitions and approach set out in the Input Methodologies (IMs) that were developed by the Commerce Commission in 2010 and last amended in 2017.

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 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 Approach to pricing methodologies for GY2021

For the pricing year commencing 1 October 2020, Firstgas is continuing to apply the existing pricing methodologies for the Maui and Non-Maui gas transmission systems. While these apply different methodologies, we have incorporated them into one disclosure document to align with the single regulated revenue cap for our Gas Transmission Business (GTB).

Continuation of the two existing pricing methodologies

Firstgas will retain the structure of the prices under the Maui Pipeline Operating Code (MPOC) and the Vector Transmission Code (VTC) for the year beginning 1 October 2020 (GY2021).

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

Unforeseen complexities in developing the IT platform, including a large degree of customisation, as well as the impact of COVID-19, have meant that the original implementation timeframes have been extended. None of the issues associated with the project are insurmountable, and Firstgas is planning for the required processes to allow the project team (and third-party vendors) to get the remaining project work done. The earliest opportunity that the project may go live is October 2021[1].

In the interim, we will continue to operate under the two existing pipeline access codes and will continue to use our existing OATIS system. The existing MPOC and VTC pricing methodologies will therefore continue to apply for GY2021. These pricing methodologies have been updated to reflect changes in allowable revenue, forecast transmission quantities, pass-through and recoverable costs.

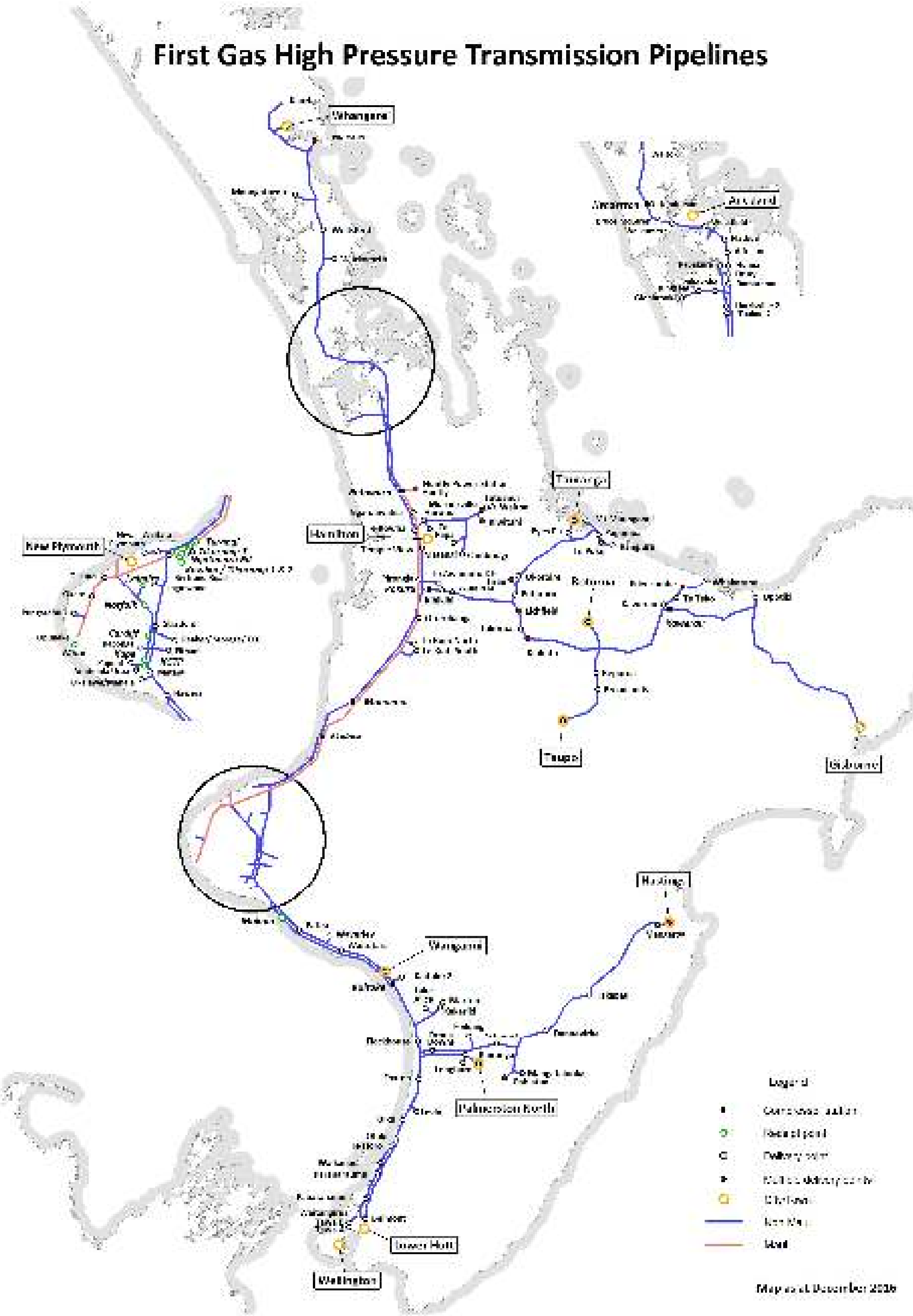
There have been no pricing structure changes for the MPOC or the VTC.

Consolidation into a single disclosure document

The MPOC and VTC methodologies are presented together in this document. This reflects the fact that the regulatory control under the current Default Price-Quality Path Determination applies to our GTB as a whole (i.e. Maui and non-Maui systems), and we are required to demonstrate that our prices for GY2021 comply with this single revenue cap.

[1] Further information is available at - https://firstgas.co.nz/about-us/gtac/

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

Firstgas' transmission business is required to set our prices to recover an amount no greater than the Forecast Allowable Revenue (FAR) under the current DPP Determination (2017 – 2022). Compliance with the FAR requirement is determined by ensuring the GY2021 prices multiplied by the forecast GY2021 quantities (the Target Revenue) is less than or equal to the FAR.

Target Revenue for GY2021 and our compliance with the FAR is set out in Table 1 below. Firstgas is compliant with its DPP revenue cap.

Table 1: Determining Target Revenue for GY2021 and compliance with the DPP

	Amount ($)	Proportion of target revenue (%)
Forecast allowable revenue (FAR)		
Forecast Net Allowable Revenue	$129,028,000	
Pass-through and recoverable costs	$241,648	
Forecast Allowable Revenue GY2021	**$129,269,648**	
Target Revenue		
Standard MPOC revenue	$35,986,821	27.9%
Standard VTC revenue	$74,104,743	57.3%
Non-standard pricing (SA and ICA revenue)	$19,162,396	14.8%
Target Revenue GY2021	**$129,253,961**	**100.0%**
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.[2]

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 ($)
Operational expenditure	$44,366,392
Pass through and recoverable costs	$241,648
Depreciation	$32,987,493
Tax	$13,834,000
Return on capital	$37,824,428
Target Revenue	**$129,253,961**

[2] 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.[3] In considering how prices should be set, we have applied those principles in the following way:

- Pricing for regions 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
- Pricing at the region 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 1**.

[3] *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 2020, we continue to apply the existing pricing methodologies for the Maui and Non-Maui transmission systems, as set by the MPOC and the VTC. The structure of prices is unchanged from previous years.[4]

As noted in section 2.1 above, our pricing methodology must ensure that prices set under the MPOC and VTC pricing methodologies comply with the revenue cap under the DPP Determination. All revenue earned from the use of the gas transmission system to transport gas – standard and non-standard transmission fees, and interconnection fees – are covered by the DPP Determination and included in the target revenue for GY2020.

3.1 Pricing under the MPOC

Pricing is set to align with the requirements of the MPOC[5] and meet the requirements under the DPP Determination. The revenue for the GTB is determined on a similar basis under the DPP Determination as specified under the MPOC. Ensuring that pricing for all transmission services is within the parameters set by the DPP 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 GY2021 continues to be based on Tariff 1 and Tariff 2. There are no non-standard contracts under the MPOC. 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. This tariff is charged at $/GJ.Km.
- **Tariff 2** is the price component intended to cover our operational costs and is set at a $/GJ

GJ.km quantities were determined historically by estimating a realistic routing of gas between receipt and delivery based on:

- Multiplying the delivery quantity and receipt quantity for each connection by its distance from Oaonui. This determines the GJ.km for all gas shipped into and out of the pipeline with reference to the southernmost Connection Point
- Deducting the sum of GJ.km of the receipt connections from the sum of GJ.km of the delivery connections to get the sum of GJ.km for all gas shipped on the system if all gas were routed via the most efficient route

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[4] In GY2020, VTC prices were set on the basis the GTAC would be in place from 1 April 2020. In GY2020, CRFs were raised to reflect an initially shorter 6-month reservation period, which was then extended by agreement to 12-months following delays in GTAC implementation. The over-run fee factor applied to the capacity reservation fee under the VTC was then reduced to 1x CRFs for the second half of GY2020. So, while the structure of prices remains the same as GY2020, prices will revert back to the standard 12-month reservation period and 10x CRF over-run fee methodology prescribed in the VTC for GY2021.

[5] The current Maui Pipeline Operating code is available on OATIS. https://www.oatis.co.nz/Ngc.Oatis.UI.Web.Internet/Common/Publications.aspx

- 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 GY2021, prices have been increased uniformly for this tariff and therefore will 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 GY2021 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 DPP Determination.

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

Table 3: Requirements under the MPOC reflect the DPP Determination

<table>
<tr><th colspan="2">MPOC (Schedule 10)</th><th>Equivalent Approach under the DPP Determination</th></tr>
<tr><td colspan="2">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</td><td>The Commission sets allowable revenue for each year of a five-year regulatory period for our GTB. 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 DPP Determination.</td></tr>
<tr><td colspan="2">Determine Tariff 1:</td><td>Determine Revenue for the GTB as a single system. Table 1 shows the expected revenue from prices under the MPOC.</td></tr>
<tr><td>(a)</td><td>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”)</td><td rowspan="3">Allowable revenue for GY2021 is allocated to proposed Tariffs under the MPOC and VTC 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.</td></tr>
<tr><td>(b)</td><td>Calculate the return of capital based on the useful life of the asset Depreciation</td></tr>
<tr><td>(c)</td><td>Aggregate the Required Return and Depreciation to derive the “Required Revenue”</td></tr>
<tr><td>(d)</td><td>Derive a GJ.km tariff (“Tariff 1”)</td><td>Tariff 1 for GY2021 is based on previous years. This tariff has increased for GY2021 to reflect this tariff has been held the same for the last two years. (refer section 5.1)</td></tr>
<tr><td>(e)</td><td>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</td><td>Tariff 1 is applied across the Maui Pipeline Shippers on the basis of quantity of gas (measures in gigajoules) to be transported multiplied by the distance of gigajoules of Gas transported.</td></tr>
<tr><td colspan="2">Determine Tariff 2:</td><td>Determine Revenue for the GTB as a single system. Table 1 shows the expected revenue from prices under the MPOC.</td></tr>
<tr><td colspan="2">The approach adopted by TSP to recover operating expenditure is to:</td><td>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.</td></tr>
</table>

MPOC (Schedule 10)		Equivalent Approach under the DPP Determination
(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 GY2021 is based on previous years. This tariff has increased for GY2021 to reflect this tariff has been held the same for the last two 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. We note that the delays with implementation of the GTAC have caused some price volatility in the last two years.

3.2 Pricing under the VTC

Pricing under the VTC applies the same methodology as in prior years[6] to set standard prices. The VTC 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 is due to non-standard prices largely being ongoing and/or negotiated on an individual basis.

Standard prices are set based on pricing regions. Pricing regions are an aggregation of connection points.[7] Delivery Points (DPs) in the same geographical location are linked to a single connection point on the transmission system. Table 4 lists the connection points which have multiple DPs linked to them. The remaining connection points have only a single DP linked to them.

Firstgas has maintained the same pricing regions for GY2021 that were applied for VTC pricing in the current period. The aggregation of delivery points into pricing regions is shown in Table 5.

[6] Further information on the development of the VTC including the factors that influenced the design such as the recovery of shared costs and prices against alternative energy sources is available in our pricing methodology for 2019. See https://firstgas.co.nz/wp-content/uploads/First-Gas-GTB-pricing-methodology-PY2019.pdf

[7] A connection is a group of delivery points feeding the same network and/or delivery points located at the same gas station

Table 4: 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

Table 5: Aggregation of delivery points into pricing regions

GY2021 Pricing Region		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
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 1 (NZRC), 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, Okaiawa \ Manaia, Marton, Matapu, Mokoia, 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, Paraparaumu, Pauatahanui 2, Tawa A, Tawa B (Nova), Te Horo, Waikanae 2
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
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, Temple View, Te Kowhai

3.2.1 Standard price setting for the VTC

Standard Price means any price that is published as part of the Confirmed Standard Transmission Fees Schedule published on OATIS.[8] Standard Prices include the prices for the Frankley Road pipeline and the price for transmission from Kapuni to Pokuru.

Prices do not flow mechanistically from cost allocations. The GTB is able to vary the fixed/variable split and move Capacity Reservation Fees by uniform or different amounts. Firstgas uses these adjustments to ensure there is parity between pricing regions and also to prepare for pricing under the single gas access transmission code (GTAC).

Standard Pricing for GY2021 largely reflects proportionality in the current period by region and price component. Further information on pricing for GY2021 is in section 5.2.

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

VTC revenue by standard price component

Standard revenue under the VTC comes from throughput fees (TPF), capacity reservation fees (CRF) and over-run fees. Around 80% of VTC standard revenue comes from capacity reservations and a further 15% of revenue comes from the throughput fees.

- The **CRF** are applied to the annual Capacity (GJ) reservations at a DP and represented by a maximum daily quantity (MDQ). Fees are based on the distance of the DP from Taranaki. Capacity reservations are 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.

  Final capacity reservations are not known at the time of setting pricing or finalising the TPM and for the purpose of setting prices, we forecast capacity reservations based on historical gas flows and observed booking patterns,
- **TPF** are applied to the GJ delivered
- **Overrun fees** are forecast as a percentage of total revenue for each pricing region. This is because the choice shippers make on the level of overruns they plan to incur can be seen as an economic decision, rather than a quantity management decision. The percentage value of overruns relative to throughput revenue plus capacity revenue for each pricing region is kept equal to the average for the previous three years.

Final prices for TPF and CRF are provided to customers by 1 September each year. Final prices must be set before final capacity reservations are received. Final prices are set based on forecast throughput quantities and forecast capacity reservations.

3.3 Determining the Target Revenue for the GTB

To show how we determine our target revenue each pricing year, Table 6 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 VTC.

Table 6: Components for inclusion in pricing methodology

Forecast Revenue from Prices	≤	Forecast Allowable Revenue
This equals the: Sum of each standard price under the MPOC multiplied by each corresponding forecast quantity for the Maui transmission network + Sum of each standard price under the VTC multiplied by each corresponding forecast quantity for the Non-Maui transmission network + 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 that includes: • Rates and levies • Balancing gas costs and revenues • Mokau compressor fuel gas costs • Capex Wash-up adjustment + 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 and any daily charges 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 standard revenue then
4. The Target Revenue for standard products can then be calculated.

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

Table 7: Target revenue compliance with forecast allowable revenue

Revenue component	Amount	
Forecast Allowable Revenue (A)	$129,269,648	
Target Revenue ($)		**Proportion of Target Revenue (%)**
Non-Standard Pricing		
• VTC ICA Revenue (B)	$1,294,927	1.0%
• VTC SA Revenue (C)	$17,867,469	13.8%
Standard Pricing		
• MPOC standard revenue (D)	$35,986,821	27.8%
• VTC standard revenue (E)	$74,104,743	57.3%
Target Revenue (F = B + C +D+E)	$129,253,961	100.0%
Difference (A – F)	$15,688	
Compliant?	**YES**	

3.4 Transmission pricing assumptions

3.4.1 Forecast gas flows

Each year Firstgas 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), that is peer reviewed by Firstgas staff. These forecasts take account of the growth in existing loads, as well as known new loads coming onto the transmission system.

In forecasting demand for the upcoming year, Firstgas and Aretê have considered the likely impact of the COVID-19 pandemic on gas demand. Aretê's original forecast, provided prior to the COVID-19 lockdown, was refreshed in July 2020 to take account of the most recent data available and the lingering effects of the lockdown. We have also sought advice from our major customers and reduced demand from prior years at some delivery points based on this advice.

The forecast delivered quantities were used to estimate the throughput quantities for each non-standard contract and each standard delivery point. Non-standard contract capacity quantities were maintained at the same values or the same proportionality to throughput as actuals for GY2021, unless advised otherwise by our customers.

3.4.2 Forecast capacity bookings

Capacity reservations have been estimated based on historical gas flows and observed booking patterns. Shippers generally seem to reserve less capacity than their annual peak demand, as a way of optimising between reservation fees and 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. Analysis of previous years suggests that shippers have tended to book capacity for the start of the gas year at a level that represents about the 37th highest day in the previous gas year.

For GY2021, 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 go back to standard pricing for 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, reflect the economic value of the service to the consumer, or address the commercial risks associated with supplying that consumer. In these 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 VTC and provides firm transmission capacity for the purposes of delivery of gas to a specific DP, or receipt of gas at Receipt Points
- **Interruptible User Contracts (IUC)**: A form of supplementary agreement that allows the Shipper to request a maximum daily quantity (MDQ) on an interruptible basis
- **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.[9] There are no non-standard contracts under the MPOC.

Where a shipper has a SA, IUC or ISC with Firstgas, they will be charged non-standard transmission fees. These are specified in the respective agreements with the shipper and are subject to the Firstgas Supplementary Agreements Policy[10]. There are 16 supplementary or interruptible contracts. Their charges represent around 13.8% of target revenue for GY2021.

Prices for these contracts are a combination of ongoing contracts on a set price path under a Transmission Pricing Agreement (TPA) and contracts that are renewed on an annual basis. Contracts that are to be renewed have had their GY2021 prices increased by the 2020 March annual weighted average

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

Consumer Price Index (CPI), or the 2020 June annual weighted average Producer Price Index (PPI) as published by Statistics New Zealand.

Interconnection agreements

We also offer an interconnection agreement (ICA) that allows a party to physically connect to the Non-Maui pipeline. The ICAs are not part of the VTC, although they reference several VTC provisions.

Interconnection fees are charged in circumstances where Firstgas has built or upgraded a delivery point or other transmission infrastructure to allow an end-user to be supplied with gas. These fees are specified in the Interconnection Agreement (ICA) with the end-user and are subject to the Firstgas Interconnection Policy. Interconnection fees are a daily charge that recovers the cost of the delivery point over the period specified in the ICA. There are 22 interconnection agreements, and charges under these ICAs represent around 1% of target revenue for GY2021.

Forecast revenue from non-standard contracts

The prices under the non-standard contracts are multiplied by the forecast quantities to give the forecast revenue for GY2021. Forecast revenue for non-standard contracts is $19,162,396. This represents 14.8% 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 VTC are not appropriate in relation to the transmission (or potential transmission) of its Gas for supply to a specific end-user or site.

In considering a request for a SA, Firstgas is likely to consider the following factors:

- 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, and Firstgas considers that retaining or connecting that End-user would be beneficial to users of the Transmission System as a whole
- Whether the Shipper (or End-user) can demonstrate that paying Firstgas' standard transmission fees would be uneconomic or unduly onerous
- As one means of providing Firstgas assurance of future revenue, e.g. where Firstgas must build a significant new asset and a particular End-user will be the sole or predominant beneficiary of that asset (which would cease to be useful were the End-user to stop using Gas)
- To provide certainty as to the availability of transmission capacity at a known price, as a means of encouraging a significant new development where that would be beneficial to users of the Transmission System as a whole
- The amount of transmission capacity requested, including whether providing it would reduce Uncommitted Operational Capacity to the extent of impeding or forestalling opportunities more beneficial to Firstgas and other users of the Transmission System
- In respect of Interruptible Agreements, situations where such an agreement will maximise the use of Uncommitted Operational Capacity in a situation where the End-user has a source of

alternate fuel and either does not require firm transmission capacity or where building new assets to provide firm capacity would be economic.

Further 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* (March 2012) available on OATIS.

3.5.3 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 1**.

3.5.4 Obligations around service interruptions

The ID Determination[11] 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) transmission services agreements and (non-standard) SAs (excluding interruptible agreements) are comparable.

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 Firstgas 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 of the fixed transmission fees.

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

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

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. A total of five 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 in the sections below.

Table 8: Forecast values for rates and levies for GY2021

Pass-through cost	Amount
Rates and levies	$2,481,000
Balancing gas costs and revenues	$432,992
Mokau fuel gas	$568,375
Capex wash-up adjustment	$799,600
Revenue cap wash-up account	($4,040,320)
Total pass through and recoverable costs	**$241,648**

3.6.1 Rates and levies

The following costs are included in this category:

- **Property rates** from GY2020 were used as a basis. These were increased by an estimated CPI
- **Commerce Act levies** have been assumed to be increase slightly from GY2020. At the time of forecasting costs, the Commerce Commission had not released its major projects timetable. We anticipate that the Commission will begin work in GY2021 on the DPP reset for gas transmission businesses and may begin work on the next Input Methodology review.[12] These projects will move more of the Commission's recovery of costs to gas businesses compared to 2020. Hence, we consider a 3% increase above the current year's levies are an appropriate estimate for GY2021
- **Utilities Disputes levies** have been assumed to be the same as GY2020. 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 GY2021 are shown in the Table 10.

Table 9: Forecast values for rates and levies

Pass-through cost	Amount
Rates	$1,720,000
Commerce Commission levies	$728,000
Utility Disputes Limited Levies	$33,000
Total	**$2,481,000**

3.6.2 Balancing gas costs and revenues

Balancing gas costs were projected based on the volumes of gas bought and sold between May 2019 and April 2020 – that is, 12 months of the most recent data as of the time of developing the pricing model. To estimate the average buy/sell price for the coming year, Firstgas calculated average prices from the months of May 2019 to February 2020. For this calculation, March and April 2020 were excluded from the analysis,

[12] The IMs are reviewed within seven year of the last review. The next review due to be completed by December 2023.

as market prices during the Covid-19 lockdown were considered not to be representative of typical market conditions.

The total costs are shown in the Table 10.

Table 10: Forecast balancing costs and revenues

Balancing gas costs	Volume May 2019-April 2020 (GJ)	Forecast volume GY2021 (GJ)	Firstgas average price ($/GJ)	Amount ($)
Total gas bought	420,100	420,100	$15.78	$6,629,059
Total gas sold	787,600	787,600	($7.98)	($6,286,644)
Total bought and sold		1,270,700		
Trading costs			$0.08	$90,577
Total costs				**$432,992**

Firstgas notes that there is a degree of uncertainty around forecasts for balancing gas costs and revenues. This is driven by two volume related factors:

- Firstgas cannot determine how much gas will need to be transacted to keep the system in balance.
- We do not know the price that those balancing gas transactions will involve, since pricing is very responsive to short term market dynamics at the time the operational response (transacting balance gas) is needed.

3.6.3 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 12-month period from May 2019 to April 2020. We used the average market price for the period from May 2019 to February 2020 to price this gas. We consider this time period is likely to be representative of future market conditions, and therefore a good basis for estimating future prices. The resulting forecast cost is **$568,375**.

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 – 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 GY2021 is **$799,600**.

3.6.5 Revenue cap wash-up

The revenue cap wash-up amount is calculated and published as part of Firstgas' DPP Compliance Statement (issued within 50 days of the end of the pricing year).[13] A time value of money adjustment as prescribed in the DPP Determination is applied to the calculated raw amount. The value for GY2021 is **($4,040,320).**

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

3.7 Pricing for subsequent years

3.7.1 Loss of a significant load

The revenue effect 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 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 Maui and non-Maui systems. This risk is becoming particularly relevant this year, with several large industrial users announcing strategic reviews of their New Zealand operations.

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

- 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, Firstgas 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. On the other hand, spreading the loss over the system could have the effect of some transmission customers bearing the cost of transmission assets that they do not use. Therefore, a degree of judgement is required in determining how to adjust prices in such situations.

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. 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 available on our website.[14]

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 VTC and MPOC, we see no reason to question compliance with this principle. However, several stakeholders have asked us to engage further on this subject, once we transition to the GTAC, 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 expect that this work will commence after GTAC has been implemented.

[14] 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 GY2021 and understanding the impact COVID-19 may have on the current year and future demand.

4.1 Discussion on access code development

Over the last year, we have continued to engage with our customers on the access codes, and therefore the pricing methodology that will apply for GY2021. While these sessions have focused on the eventual implementation of a single access code for the transmission network (the GTAC), customer have supported remaining on the VTC and MPOC until the technology solution is in place to support the new code.

Firstgas has continued with pricing under the MPOC and VTC in consultation with shippers, gas producers, major gas users and other stakeholders.

4.2 Impact of COVID-19

The COVID-19 pandemic has had, and will continue to have, an impact on New Zealand. Throughout the lockdown in 2020, Firstgas continued to provide essential services, by transporting gas across both our transmission system and distribution networks to all of our customers, including hospitals and other essential service providers.

During Alert Level 4, many of our large industrial customers had to cease operations or reduce their gas consumption. We have worked with our customers where possible to offer tailored payment plans to assist them through this difficult period. We have also continued to work with our customers to understand their likely demand for gas in GY2021. For some customers we expect to see a decrease in demand.

4.3 Consultation on provisional prices

We provided provisional prices under the VTC to customers on 29 May 2020. Customers did not provide any feedback on the provisional prices and final prices were released on 1 September 2020.

Prices for the MPOC were provided to customers on 31 July 2020, in line with requirements under the MPOC.

5 Final prices for GY2021

This section sets outs the final standard prices for GY2021 that have been determined under the MPOC and VTC.

Standard pricing for GY2021 will increase slightly under the MPOC and decrease slightly for some tariffs under the VTC. Firstgas has taken the opportunity to align price increases under the MPOC and VTC over the last two years. In GY2020, prices under the MPOC were held steady in anticipation of implementing the single gas access transmission code (GTAC). This meant for GY2020 prices under the VTC increased by more than CPI.[15] For GY2021, we have reduced or held steady most tariffs under the VTC, and increased MPOC prices so that price increases under both codes over the two years are more aligned.

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

The proportion of target revenue that is collected through each contract for GY2021 is summarised in Table 11 below.

Table 11: Proportion of target revenue by price component for GY2021

	Amount ($)	Proportion of target revenue (%)
Standard MPOC revenue		
Tariff 1	$ 24,736,756	19.2%
Tariff 2	$ 11,250,065	8.7%
Standard Target revenue under MPOC	**$35,986,821**	**27.9%**
Standard VTC revenue		
Capacity Reservation Fees (CRF)	$ 58,926,992	45.6%
Throughput Fees (TPF)	$ 11,134,990	8.6%
Over-run Fees	$ 4,042,762	3.1%
Target standard VTC revenue	**$74,104,743**	**57.4%**
Total standard target revenue	**$110,091,565**	**85.2%**
Non-standard VTC target revenue	$19,162,396	14.8%
Total target revenue	**$129,253,961**	**100.0%**

The change in standard prices for GY2021 under the MPOC and VTC are outlined below.

[15] In GY2020, VTC prices were set on the basis the GTAC would be in place from 1 April 2020. In GY2020, CRFs were raised to reflect an initially shorter 6-month reservation period, which was then extended by agreement to 12-months following delays in GTAC implementation. The over-run fee factor applied to the capacity reservation fee under the VTC was then reduced to 1x CRFs for the second half of GY2020. So, while the structure of prices remains the same as GY2020, prices will revert back to the standard 12-month reservation period and 10x CRF over-run fee methodology prescribed in the VTC for GY2021.

5.1 MPOC prices for GY2021

MPOC pricing for GY2021 is 4% higher than pricing for GY2020. This increase in pricing reflects the fact that pricing under the MPOC was held steady over the last two years, whilst pricing under the VTC increased. When setting pricing for GY2020, it was expected the MPOC would only be in place for part of the year and thus pricing under the MPOC was held unchanged from GY2019.

MPOC pricing for GY2021 is set out in Table 12 below.

Table 12: GY2021 MPOC prices

Tariff	Unit	GY2020	GY2021	Percentage change
Tariff 1	$ / GJ.km	0.001601	**0.001665**	4.0%
Tariff 2	$ / GJ	0.073132	**0.076057**	4.0%

5.2 VTC prices for GY2021

Standard pricing for GY2021 largely reflects proportionality in the current period by region and price component. We have taken to opportunity this year to align price increases over the last two years under the MPOC and VTC and continue to move the CFR for the Hamilton region closer to the CFR for other regions.

Specific actions for GY2021 pricing year include:

- An increase in the CRF for the Hamilton from $178/GJ.MDQ to $196/GJ.MDQ. The CFR is based on the distance of supply from where the gas is injected in Taranaki. Under contracts with the Hamilton region, the rate was started low and we may increase the rate by up to 10% per year until the CFR is aligned with the methodology used for other regions. For GY2021, we have increased the CFR rate by 10%.
- A decrease in the CRF for all other regions by 4%. The decrease in GY2021 aligns price increases over the two-year period (GY2020 and GY2021) between the MPOC and VTC, and largely reflects an increase in CPI over those two years. The implementation of the GTAC was expected to occur from 1 April 2020. When this was delay, price changes permitted under the MPOC and VTC were limited for GY2020. Changing capacity reservations combined with restrictions on price increases to other fees and prices under the MPOC resulted in higher than normal increases to the CRF in GY2020. We have taken the opportunity to reduce the CRF this year so that increases over the two-year period largely reflect the increase in CPI over the period.
- The TPF for all pricing regions, except for Frankley Road are held at the same rate as GY2020. The increase at Frankley Road is to align prices across all regions. Frankley Road prices did not increase in GY2020 whilst other regions did.

Table 13 summarises the changes in price between GY2020 and GY2021 and Table 14 summarises the standard revenue by region under the VTC for GY2021.

Table 13: GY2021 VTC standard prices

Pricing region	GY2020		GY2021		Percentage change	
	TPF $/GJ	CRF $/GJ.MDQ	TPF $/GJ	CRF $/GJ.MDQ	TPF %	CRF %
Taranaki	$0.10	$87	**$0.10**	**$84**	0%	-4.0%
Waikato South	$0.10	$384	**$0.10**	**$369**	0%	-4.0%
Auckland	$0.10	$373	**$0.10**	**$358**	0%	-4.0%
Northland	$0.10	$567	**$0.10**	**$544**	0%	-4.0%
Waikato North	$0.10	$384	**$0.10**	**$369**	0%	-4.0%
South Taranaki - Whanganui	$0.10	$362	**$0.10**	**$348**	0%	-4.0%
Manawatu – Horowhenua	$0.10	$373	**$0.10**	**$358**	0%	-4.0%
Hawke’s Bay	$0.10	$384	**$0.10**	**$369**	0%	-4.0%
Kapiti - Wellington	$0.10	$461	**$0.10**	**$443**	0%	-4.0%
Waikato East	$0.10	$384	**$0.10**	**$369**	0%	-4.0%
Bay of Plenty West	$0.10	$472	**$0.10**	**$453**	0%	-4.0%
Bay of Plenty South	$0.10	$494	**$0.10**	**$474**	0%	-4.0%
Bay of Plenty East	$0.10	$516	**$0.10**	**$495**	0%	-4.0%
Eastland	$0.10	$538	**$0.10**	**$516**	0%	-4.0%
Hamilton	$0.10	$178	**$0.10**	**$196**	0%	10%
Frankley Road	$0.29	n/a	**$0.31**	**n/a**	6.9%	n/a

Table 14: GY2021 VTC standard forecast revenue

	Prices		Revenue ($)			
Pricing Region	**TPF ($/GJ)**	**CRF ($/GJ.MDQ)**	**TPF**	**CRF**	**Over-Run**	**Total Revenue ($)**
Taranaki	$0.10	$84	1,140,884	$114,088	$369,690	$48,528
Waikato South	$0.10	$369	4,198,716	$419,872	$7,366,757	$698,002
Auckland	$0.10	$358	16,337,166	$1,633,717	$20,896,483	$1,013,891
Northland	$0.10	$544	144,997	$14,500	$334,360	$15,076
Waikato North	$0.10	$369	1,964,006	$196,401	$3,167,839	$242,011
South Taranaki - Whanganui	$0.10	$348	1,847,387	$184,739	$2,876,194	$188,604
Manawatu - Horowhenua	$ 0.10	$358	2,267,033	$226,703	$3,472,851	$213,132
Hawkes Bay	$0.10	$369	1,877,667	$187,767	$3,027,882	$216,977
Kapiti - Wellington	$0.10	$443	4,168,922	$416,892	$6,624,984	$579,334
Waikato East	$0.10	$369	738,733	$73,873	$1,262,274	$170,962
Bay of Plenty West	$0.10	$453	1,216,846	$121,685	$1,833,422	$198,561
Bay of Plenty South	$0.10	$474	1,717,159	$171,716	$3,077,974	$210,559
Bay of Plenty East	$0.10	$495	1,392,653	$139,265	$2,502,261	$92,439
Eastland	$0.10	$516	433,534	$43,353	$807,298	$71,383
Hamilton	$0.10	$196	1,715,145	$171,515	$1,306,721	$83,304
Frankley Road	$0.31	n/a	22,641,629	$7,018,905	n/a	n/a
Total Standard Revenue (VTC)			**$11,134,990**	**$58,926,992**	**$4,042,762**	**$74,104,743**

Appendix 1: 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 based on the MPOC and VTC 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 VTC only.

Table A: Compliance of standard pricing with the Pricing Principles

Pricing principles	Pricing methodology consistency	
	MPOC	**VTC**
(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 VTC is not fully consistent with this principle. Although the VTC methodology inherited from Vector did consider incremental and standalone costs, Firstgas believes that the Pricing Regions used by Vector do not reflect the commonality of the delivery points within those regions. To address this issue, while avoiding unnecessary price changes, Firstgas has adjusted prices in prior years to better reflect the differences between Pricing Regions. In GY2021 we have continued to adjust regions to this approach 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 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 TPM is based on location and the pricing structure inherited under previous versions of the TPM.

Pricing principles	Pricing methodology consistency	
	MPOC	VTC
(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 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 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. Prices were held steady in GY2020 while prices under the VTC increased. Increases under the MPOC in GY2021, will bring price increases over the Firstgas transmission network back into alignment.	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: Compliance of non-standard pricing under the VTC with the Pricing Principles

This table shows how the use of non-standard pricing can allow us to better comply with the pricing principles. We have compared compliance 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. 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 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.

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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 VTC**
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 2020. 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 will be publicly disclosed by 30 September 2020. The pricing methodology for GY2020 and GY2021 is based on the MPOC and VTC. There has been no change to the methodology so clause 2.4.1 of the ID Determination applies.	
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 VTC**
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.	
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

Principle	Reference / description	
	Pricing methodology for MPOC	**Pricing methodology for VTC**
(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

Director Certificate for TPM

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

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

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

Director: Mark Adrian Ratcliffe	Director: Euan Richard Krogh
12 August 2020	12 August 2020
Date	Date