GasNet Limited

2018/19 Pricing Methodology

Gas Distribution Network Services

Valid from 1 October 2018 to 30 September 2019

Pursuant to:
Gas Distribution Information Disclosure Determination 2012

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1.0 EXECUTIVE SUMMARY

This is the third pricing methodology based on the new pricing structure proposed in 2013 to reduce the number of Load Groups and closer align to those of other gas distribution network operators in New Zealand.

This document is based on the new pricing structure and prices that apply to the pricing year commencing 1 October 2018. Information on the methodologies and pricing for previous years can be downloaded from GasNet's website at www.gasnet.co.nz.

This pricing covers GasNet's five discrete distribution systems already well-established in the Whanganui, Rangitikei and South Taranaki regions. The existing systems are small and have negligible difference in performance. As such prices are based on consolidation of assets and costs with prices applied evenly across all networks.

The pricing methodology is designed to demonstrate that GasNet's prices are consistent with the pricing principles and other regulatory obligations in the Gas Distribution Services Information Disclosure Determination 2012.

GasNet's annual target revenue requirement seeks the recovery of costs and an appropriate return on assets employed, expressed as follows:

Total Revenue Requirement (TRR)	=	Return on Assets	+	Depreciation	+	Operating Costs	+	Pass-through Costs	-	DPP Revenue Constraint

GasNet's pricing model separately allocates each component of the revenue requirement to each Load Group. This includes the allocation of consumers into the Load Groups.

Cost allocators employed are the number of consumers, throughput (GJ), hourly capacity demand and asset base replacement cost and depreciated replacement cost.

The customer numbers, throughput and revenue for each Load Group for the 2018/19 Pricing Year is set out in the following table:

Load Group	Consumers Connected	Throughput (GJ)	2017/18 Pricing Year Total Revenue	2018/19 Pricing Year Total Revenue	2018/19 Pricing Year Change
G12	9,794	244,666	$ 3,281,865	$ 3,334,652	1.6%
G50	115	41,049	$ 342,268	$ 347,977	1.7%
G180	34	68,950	$ 397,658	$ 400,599	0.7%
G450	7	114,251	$ 177,077	$ 177,814	0.4%
G1000	10	835,848	$ 146,732	$ 190,759	30.0%
	9,960	1,304,765	$ 4,345,600	$ 4,451,800	2.4%

The prices that apply for the 2018/19 Pricing Year are set out in the following table.

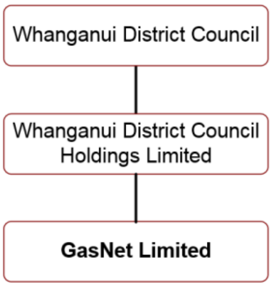
Load Group	2017/18 Pricing Year Fixed ($/day)	2017/18 Pricing Year Variable ($/GJ)	2018/19 Pricing Year Fixed ($/day)	2018/19 Fixed Change	2018/19 Pricing Year Variable ($/GJ)	2018/19 Variable Change
G12	$0.430	$7.252	$ 0.435	1.2%	$ 7.274	0.3%
G50	$1.500	$6.835	$ 1.500	0.0%	$ 6.943	1.6%
G180	$5.160	$4.852	$ 5.160	0.0%	$ 4.881	0.6%
G450	$40.000	$0.658	$ 40.000	0.0%	$ 0.662	0.6%
G1000	Individually Priced		Individually Priced			

GasNet welcomes feedback from interested persons on any aspect of this Pricing Methodology document.

2.0 BACKGROUND

2.1 About GasNet

GasNet Limited is 100% owned by Whanganui District Council Holdings Limited, a “Council Controlled Trading Organisation”.



GasNet Limited (“GasNet”) commenced trading on 1 July 2008 after purchasing the network and metering business from Wanganui Gas Limited. Previously GasNet had been operating as an independent trading division of Wanganui Gas Limited and was responsible for managing the network and metering assets for the company.

On 30 June 2017 GasNet Limited and its parent Wanganui Gas Limited were amalgamated to become GasNet Limited.

2.2 Supply Area Coverage

GasNet’s natural gas distribution network comprises approximately 10,000 connections across 5 discrete distribution systems located within the Whanganui, Rangitikei and South Taranaki regions serving the following areas:

- Whanganui;
- Marton;
- Bulls;
- Flockhouse; and
- Waitotara.

Further information on these networks and their coverage can be found within GasNet’s Asset Management Plan which can be downloaded at www.gasnet.co.nz/gasnet-disclosures.

2.3 Regulatory Requirements

2.3.1 Pricing Principles

The Commerce Commission’s *Gas Distribution Services Input Methodologies Determination 2012* requires compliance of GasNet’s pricing and its methodology with specified pricing principles in addition to disclosure of the extent of consistency with the principles and reasons for any inconsistency. The pricing principles are provided in section 0 along with an explanation of how they are reflected in this pricing methodology.

2.3.2 Revenue Requirements

GasNet’s revenue requirement is established in accordance with the Commerce Commission’s *Gas Distribution Services Default Price-quality Path Determination 2017.*

2.3.3 Information Disclosure

The Commerce Commission’s *Gas Distribution Information Disclosure Determination 2012* requires GasNet and all other gas distribution businesses to publicly disclose at the beginning of each Pricing Year, the methodology used to determine the prices payable for the provision of gas distribution services.

An extract of the specific requirements from the determination has been provided in Appendix 2.

2.3.4 Access to Determinations

The latest version of the determinations referred to in 2.3.1, 2.3.2 and 2.3.3 above can be downloaded from the Commission's website at www.comcom.govt.nz.

2.4 Strategic Review Leading to New Pricing Methodology

The Pricing Methodology and Pricing Structure specified within this document presents the results from a strategic review undertaken by GasNet in 2013 aimed at delivering a price structure that:

a) more closely reflected the underlying costs incurred to service each consumer group by incorporating an updated cost allocation methodology;

b) was streamlined where possible by removing unnecessary price options to improve administration efficiency;

c) reflected the high fixed cost component of operating a gas distribution pipeline business;

d) minimised, if not eliminated, the need to offer special "non-standard" prices;

e) provided for the cessation of charges when a consumer's installation is physically isolated from GasNet's distribution network;

f) was subject to an implementation plan that minimised price shock for consumers; and

g) complied with the law, in particular the Commerce Commission's "Pricing Principles" (section 2.5.2 of the Commerce Act (Gas Distribution Services Input Methodologies) Determination 2012).

In order to minimise price shock to consumers, GasNet transitioned to this Pricing Methodology and Pricing Structure from 2013 until its implementation on 1 October 2016.

Information on the methodologies and pricing for previous years and the reasoning for the reform to the pricing methodology can be downloaded from GasNet's website at www.gasnet.co.nz.

3.0 PRICING STRUCTURE

The following table provides the Load Groups applicable from 1 October 2018.

Load Group	Criteria	Consumers (No.)	Throughput (GJ)
G12	Up to 13 scmh	9,794	244,666
G50	> 13 and ≤ 50 scmh	115	41,049
G180	> 50 and ≤ 180 scmh	34	68,950
G450	>180 scmh	7	114,251
G1000	Individually Priced	10	835,848
		9,960	1,304,765

4.0 CONNECTION STATUS

Each consumer connection on GasNet's network is identified by a unique identifier, known as an ICP, which is assigned a status code based on its connection status.

In the case of an ICP that has been disconnected there are a range of status codes reflecting the wide range of scenarios that could give cause for a disconnection. In this situation where an ICP is physically disconnected from the network and gas cannot flow, daily fixed charges do not apply.

The following table lists each status code and whether the fixed daily charges apply.

ICP Status Code	Valid Connection Status	Connection Status Code	Network Fixed Daily Charges Apply
NEW	Pre-activation, service has not yet been installed	NEW	✗
READY	Gas ready to flow	GIR	✗
ACTC	Gas able to flow	GAS	✓
ACTV	Gas able to flow	GAS	✓
INACT	Gas vacant disconnect – GMS remains, supply capped or plugged	GVC	✗
	Gas vacant disconnect – GMS removed, supply capped or plugged	GVM	✗
	Gas currently not required – GMS remains, supply capped or plugged	GNC	✗
	Gas currently not required – GMS removed, supply capped or plugged	GNM	✗
	Gas maintenance disconnect – GMS remains, supply capped or plugged	GMC	✗
	Gas maintenance disconnect – GMS removed, supply capped or plugged	GMM	✗
	Gas maintenance disconnect – GMS remains, service disconnected upstream of service valve by network operator	GMU	✗
	Gas safety disconnect – GMS remains, supply capped or plugged	GSC	✗
	Gas safety disconnect – GMS removed, supply capped or plugged	GSM	✗
	Gas safety disconnect – GMS remains, service disconnected upstream of service valve by distributor	GSU	✗
INACP	Gas permanent disconnect ready for GMS removal – GMS remains, supply capped or plugged	GPC	✗
	Gas permanent disconnect ready for decommissioning – GMS removed, supply capped or plugged	GPM	✗
DECR	Service disconnected from network outside property and service abandoned	GDE	✗

5.0 PRICING METHODOLOGY

5.1 Distribution Networks

As the combined size of GasNet's gas distribution networks is small and as there are negligible differences in performance within or between each of the 5 existing discrete networks listed in section 2.2 above, there is no benefit in segmenting them into different pricing networks, sub-networks, or geographic areas. The Pricing Methodology and prices are therefore based on consolidation of assets and costs, with prices applied evenly across all networks.

5.2 Revenue Requirements

GasNet's annual target revenue seeks the recovery of costs and an appropriate return on the assets employed, expressed mathematically as follows;

$$\text{Total Revenue Requirement (TRR)} = \text{Return on Assets} + \text{Depreciation} + \text{Operating Costs} + \text{Pass-through Costs} - \text{DPP Revenue Constraint}$$

Where:

Return on Assets =	a target return on the forecast Regulatory Asset Base (RAB), using a pre-tax weighted average cost of capital of 7.95% (based on the 75th percentile estimate of vanilla WACC of 6.41% allowable under the DPP with the cost of equity grossed up for tax)
Depreciation =	the forecast Regulatory Asset Base (RAB) depreciation for the Pricing Year
Operating Costs =	the forecast Operating Costs attributable to the network business over the Pricing Year but excluding Pass-through Costs

Pass-through Costs = the forecast operating costs to be paid during the Pricing Year that fall within the same definition in the *Gas Distribution Services Input Methodologies Determination 2012*, which for GasNet include, but are not limited to:

- Local and Regional Authority rates on GasNet's network assets payable under the Local Government (Rating) Act 2002; and
- Levies payable to the Commerce Commission under the Commerce (Levy for Control of Natural Gas Services) Regulations 2005; and
- Levies payable as a member of the Utility Disputes Limited Scheme.

DPP Revenue Constraint = the amount, if any, that is required to align the target revenue with the Allowable Notional Revenue (ANR) under the Default Price-quality Path (DPP).

5.3 Asset Valuation

The 30 June 2017 RAB, being the most recent audited valuation, has been applied in GasNet's Pricing Model for 2018/19 Pricing Year.

5.4 Revenue Allocation

5.4.1 Pricing Model

The pricing model separately allocates each component of the Revenue Requirement, as outlined in 5.2 above, to each Load Group using appropriate cost allocators, based on the following key processes:

- Identification of the Total Revenue Requirement to be recovered from fixed and variable charges, by cost component as outlined above in 5.2;
- Allocation of consumers into the Load Groups consistent with the structure discussed above in 3.0;
- Input of the identifying characteristics for each Load Group (e.g. number of ICPs, GJ, MHQ, etc.) which are used to allocate costs;
- Allocation of each component of the Total Revenue Requirement to the Load Groups using cost of supply allocators (referred to in 5.4.2 and 5.4.3 below) in order to determine the revenue to be recovered from each Load Group;
- Once the revenue requirement for each Load Group is determined, specification of the proportion of fixed and variable prices in order to test alternative price options;
- Application of the price options developed for each Load Group across the throughput bands evident in each Load Group to test the impact on high/average/low use consumers within each Load Group; and
- Refinement the price options as required in order to meet regulatory requirements, management of price shock, and implementation of pricing signals consistent with the pricing principles.

5.4.2 Allocation of Total Revenue Requirement

The Total Revenue Requirement is derived from the sum of different cost components as outlined in 5.2 above, each of which being allocated using a range of applicable allocators. Allocators are selected from available data and where such data is not available, proxies based on the underlying cost drivers.

The following table provides the cost allocators that have been applied to the cost components that comprise the Total Revenue Requirement.

Total Revenue Requirement Cost Item	Cost Allocator
Return on Assets	Depreciated Replacement Cost
Depreciation	Relacement Cost
Operating Costs	
Direct	Depreciated Replacement Cost
Indirect	Number of ICP's
Pass-through	Depreciated Replacement Cost
DPP Revenue Constraint	Depreciated Replacement Cost

Please note that the DPP Revenue Constraint cost item is not technically a cost but the amount, if any, by which the Total Revenue Requirement may be required to be reduced such that GasNet does not breach its price/revenue cap set by the Commerce Commission under its DPP.

5.4.3 Cost Allocators

The Cost Allocators described in 5.4.2 above and others used within the Pricing Model in the determination of prices, are described in further detail as follows.

5.4.3.1 Number of Consumers (ICP's)

The number of ICP's within each Load Group is based on the number of consumers expected to be connected during the Pricing Year with an ICP Status Code of "ACTC" and "ACTV" in the Gas Registry.

The ICP inventory is then consolidated to provide the number of ICP's that are connected to each of the 3 network pressure systems (IP, MP & LP) within each Load Group, for further use in establishing the value of the assets allocated to each Load Group, discussed in further detail in 5.4.3.4 below.

Load Group	Network Pressure System			Number of ICP's
	Intermediate Pressure (IP)	Medium Pressure (MP)	Low Pressure (LP)	
G12	2	2,568	7,224	9,794
G50	6	79	30	115
G180	5	27	2	34
G450	3	4	-	7
G1000	7	3	-	10
	23	2,681	7,256	9,960

5.4.3.2 Throughput (GJ)

The annual throughput for each Load Group is the consolidation of the throughput for each individual ICP (consumer) averaged over the four year period from 1 July 2014 to 30 June 2018.

Load Group	Network Pressure System			Total Consumption (GJ)
	Intermediate Pressure (IP)	Medium Pressure (MP)	Low Pressure (LP)	
G12	21	74,735	169,910	244,666
G50	3,184	30,383	7,482	41,049
G180	8,741	59,375	834	68,950
G450	17,766	96,486	-	114,251
G1000	752,911	82,937	-	835,848
	782,624	343,915	178,225	1,304,765

5.4.3.3 Hourly Capacity Demand

For the purpose of allocating asset values to each Load Group the hourly capacity demands of the consumers within each group has been attributed by their MHQ adjusted to allow for diversity of consumer demand.

The largest population of consumers of all the Load Groups are those with the industry standard 6m^3 entry level meter making up almost 96%, the majority of which are domestic. A capacity demand MHQ of 0.5scmh has been assigned to the predominantly domestic population of consumers with these meters, based on the actual maximum hourly quantity consumed in a metered residential suburb of 92 consumers within GasNet's Wanganui network in 2012. Engineering judgements have been made to adjust the hourly capacity demand for all other Load Groups with the ratio of diversified MHQ progressively increasing as the capacity of the Load Groups increase and the number of consumers decrease, until at the largest Load Group the capacity demand is very close to the actual rated capacity.

Load Group	Network Pressure System			Total Hourly Capacity Demand (scmh)
	Intermediate Pressure (IP)	Medium Pressure (MP)	Low Pressure (LP)	
G12	3	1,464	4,067	5,534
G50	55	975	348	1,378
G180	360	2,220	120	2,700
G450	950	1,000	-	1,950
G1000	-	-	-	-
	1,368	5,659	4,535	11,562

Note that the values for the G1000 Load Group are nil as this Hourly Capacity Demand cost allocator is used for asset allocation purposes only, and the G1000 Load Group has been allocated their share of the actual assets as outlined in 5.4.3.4 below.

5.4.3.4 Replacement Cost and Depreciated Replacement Cost

The 30 June 2017 Regulatory Asset Base (RAB) has been applied as the latest audited valuation.

With the exception of the G1000 Load Group, assets are allocated to each Load Group based on their Hourly Capacity Demand on each of the 3 pressure systems within the networks (IP, MP & LP) as outlined in 5.4.3.3 above.

In the case of the G1000 Load Group, the assets for each individual ICP within the group are allocated on their share of the value of the specific assets utilised by each ICP from the Sales Gate to the GMS installation, plus an allocation for non-infrastructure assets, the latter treatment being consistent with that applied to the other Load Groups. This variation is necessary due to the distortion created by these ICP's being located close to the Sales Gate and with relatively high hourly capacity demands, which results in an over-allocation of asset value.

Based on the allocation methodology described above, the apportionment of asset values to Load Groups for the 30 June 2017 RAB are as follows:

Replacement Cost	IP		MP		LP		Total	
G12	$ 1,309	0.1%	$ 2,554,703	23.3%	$ 32,107,169	89.7%	$ 34,663,181	71.9%
G50	$ 25,703	1.8%	$ 1,701,391	15.5%	$ 2,747,036	7.7%	$ 4,474,130	9.3%
G180	$ 168,237	11.8%	$ 3,873,935	35.3%	$ 947,254	2.6%	$ 4,989,426	10.4%
G450	$ 443,958	31.1%	$ 1,745,016	15.9%	$ -	0.0%	$ 2,188,974	4.5%
G1000	$ 786,937	55.2%	$ 1,094,783	10.0%	$ -	0.0%	$ 1,881,719	3.9%
	$ 1,426,143		$ 10,969,828		$ 35,801,459		$ 48,197,430	

Depreciated Replacement Cost	IP		MP		LP		Total	
G12	$ 662	0.0%	$ 1,373,612	12.5%	$ 14,599,146	40.8%	$ 15,973,420	33.1%
G50	$ 13,010	0.9%	$ 914,803	8.3%	$ 1,249,079	3.5%	$ 2,176,892	4.5%
G180	$ 85,158	6.0%	$ 2,082,937	19.0%	$ 430,717	1.2%	$ 2,598,811	5.4%
G450	$ 224,722	15.8%	$ 938,260	8.6%	$ -	0.0%	$ 1,162,981	2.4%
G1000	$ 503,688	35.3%	$ 755,436	6.9%	$ -	0.0%	$ 1,259,124	2.6%
	$ 827,239		$ 6,065,048		$ 16,278,941		$ 23,171,229	

6.0 2018/19 PRICING YEAR

6.1 Revenue Requirements

Based on current estimates of the cost components and the methodology outlined in 5.2 above, the Total Revenue Requirement for the 2018/19 Pricing Year is as follows:

Cost Item	Total Revenue Requirement
Return on Assets	$ 1,920,300
Depreciation	$ 846,000
Operating Costs	
Direct	$ 856,250
Indirect	$ 840,250
Pass-through	$ 74,000
DPP Revenue Constraint	-$ 85,000
Total Revenue Requirement	$ 4,451,800

6.2 Revenue Requirement Allocation to Load Groups

Based on the methodology and cost components outlined above, the Revenue Requirement for 2018/19 for each Load Group is as set out in the following table.

Load Group	Consumers Connected	Throughput (GJ)	2017/18 Pricing Year Total Revenue	2018/19 Pricing Year Total Revenue	Change
G12	9,794	244,666	$ 3,281,865	$ 3,334,652	1.6%
G50	115	41,049	$ 342,268	$ 347,977	1.7%
G180	34	68,950	$ 397,658	$ 400,599	0.7%
G450	7	114,251	$ 177,077	$ 177,814	0.4%
G1000	10	835,848	$ 146,732	$ 190,759	30.0%
	9,960	1,304,765	$ 4,345,600	$ 4,451,800	2.4%

6.3 Prices for 2018/19 Pricing Year

The prices that apply from 1 October 2017 for the 2018/19 Pricing Year are set out in the following table, in Appendix 1 and can be downloaded from GasNet's website at www.gasnet.co.nz/disclosures.

Load Group	2017/18 Pricing Year		2018/19 Pricing Year			
	Fixed ($/day)	Variable ($/GJ)	Fixed ($/day)	Change	Variable ($/GJ)	Change
G12	$0.430	$7.252	$ 0.435	1.2%	$ 7.274	0.3%
G50	$1.500	$6.835	$ 1.500	0.0%	$ 6.943	1.6%
G180	$5.160	$4.852	$ 5.160	0.0%	$ 4.881	0.6%
G450	$40.000	$0.658	$ 40.000	0.0%	$ 0.662	0.6%
G1000	Individually Priced		Individually Priced			

6.4 Fixed and Variable Charge Apportionment

On aggregate the total revenue from fixed daily charges comprise 44.4% and the variable throughput charges 55.6% of the total annual Revenue Requirement for the 2018/19 Pricing Year based on the pricing indicated in section 6.3 above.

7.0 PRICING METHODOLOGY REVIEW

Whilst the review of GasNet's pricing methodology in 2013 was considered to be a periodic review that would apply to the following five or more years (at least for the first regulatory period from 1 July 2013 to 30 September 2017), the methodology is subject to on-going review.

Significant changes to the methodology are subject to consultation with interested parties as considered appropriate for the change proposed. Changes that are minor by nature are referred to in the annual Pricing Methodology document produced by GasNet and published on its website prior to the commencement of the Pricing Year to which it applies.

8.0 FIVE YEAR PRICING STRATEGY

Having implemented its new Pricing Methodology in 2016, there are no plans to make further changes to GasNet's pricing structure in the next five year period.

9.0 COMPLIANCE WITH THE PRICING PRINCIPLES

GasNet is required under the IDD to describe the extent to which its pricing methodology is consistent with a set of gas distribution pricing principles. The table below summarises these pricing principles and how they are reflected in this pricing methodology.

Pricing Principle	Extent to which pricing methodology is consistent with pricing principles
(1) Prices are to signal the economic costs of service provision, by:	
(a) being subsidy free (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;	Incremental costs are the additional upfront and ongoing costs GasNet face in connecting a new consumer to the network. This typically includes costs associated with connection assets, ongoing operations and maintenance costs specific to that consumer, and network augmentation costs. GasNet's capital contributions policy requires a capital contribution from new consumers when the incremental capital costs associated with a new connection exceed the present value of expected future revenues. The combination of capital contributions and gas distribution prices therefore ensures that our prices are in excess of incremental capital costs. Operating and maintenance expenditure is recovered through distribution prices. Our fixed charge, based on a daily charge, ensures that we at least recover some of these incremental costs regardless of throughput. Charges also increase with the capacity size of the connection, which aligns pricing to incremental operating costs associated with various connection sizes. Stand alone costs are the full cost a consumer would face in being supplied from an alternative gas distribution system or alternative form of supply. For gas, stand alone cost is most likely to represent the full cost of converting from gas to electricity, including the cost of replacing gas appliances. GasNet has set its prices and pricing structures mindful of the fact that consumers have alternative supply options. Our pricing, and commercial business proposition, seeks to incentivise consumers connecting, and remaining connected, to distributed gas. Large consumers may also have options to bypass the distribution network for alternative networks, particularly where the consumer is close to a gas sales gate. GasNet offers non-standard pricing contracts to a number of large sites. These non-standard pricing arrangements are individually priced but based on the same cost-based methodology as applied to other consumers. They reduce bypass risk by making it economic for these consumers to connect, and remain connected, to the network.
(b) having regard, to the extent practicable, to the level of available service capacity; and	GasNet sets its consumer groups to align with standard load group types based on typical connection sizes. This aligns pricing with various end-consumer usage profiles and with the capacity of their connection assets, a key network cost driver.

Pricing Principle	Extent to which pricing methodology is consistent with pricing principles
(c) signalling, to the extent practicable, the impact of additional usage on future investment costs.	GasNet's prices are based on a daily fixed supply charge and a throughput based tariff (in GJs). The throughput tariff ensures consumers that use more are charged more. This basic principle is effective in signalling the impact of additional usage on future investment costs. Similarly, the supply charge applying to each load grouping increases relative to the standard capacity size of the connection. This signals that larger connections typically have higher throughput and peak demand and therefore create higher investment costs.
(2) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.	GasNet's pricing is not based on willingness to pay or demand responsiveness considerations as this is not practicable to assess, but on load groupings based on typical connection sizes. We consider this most appropriately aligns with our investments in capacity, which is a key network cost driver.
(3) Provided that prices satisfy (1) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:	
(a) discourage uneconomic bypass;	This principle allows for pricing and other incentives to discourage consumers bypassing GasNet's network to another supply alternative. As discussed above, GasNet seeks to discourage consumers bypassing the network in setting non-standard prices for large consumers close to a sales gate. This pricing recognises the alternative supply options these consumers have available to them.
(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.	This principle allows for negotiation over price in recognition of different levels of service or other arrangements of value to consumers. Price and quality trade-offs are primarily addressed under our capital contributions policy when scoping connection asset specifications. We are also always open to discussing non-standard pricing arrangements where appropriate.
(4) Development of prices is transparent, promotes price stability and certainty for consumers, and changes to prices have regard to the effect on consumers.	This methodology transparently sets out the approach we have adopted to determine prices for consumers connection to the network, and is publicly available via GasNet's website www.gasnet.co.nz.

Appendix 1 – Network Services Price Schedule: Effective 1 October 2018

Network Services Price Schedule

Effective from 1 October 2018

Load Group	Capacity (m^3/hr)		Estimated Number of Consumers	Charge Type	Unit Charges	New Prices from 1 October 2018	Prices up to 30 September 2018
	More Than	Less than or Equal To					
G12	0	13	9,794	Fixed	$/day	0.435	0.430
				Variable	$/GJ	7.274	7.252
G50	13	50	115	Fixed	$/day	1.500	1.500
				Variable	$/GJ	6.943	6.835
G180	50	180	34	Fixed	$/day	5.160	5.160
				Variable	$/GJ	4.881	4.852
G450	Greater than 180		7	Fixed	$/day	40.000	40.000
				Variable	$/GJ	0.662	0.658

Notes
1. **All rates are exclusive of GST.**
2. Charges apply when the ICP Status Code in the Gas Registry is ACTC or ACTV
3. Additional information is available on our website www.gasnet.co.nz.
4. If you have any questions please email us at enquiries@gasnet.co.nz or call us at (06) 349 2050.

Appendix 2 - Information Disclosure Determination Requirements

Clause 2.4 of the Commerce Act (Gas Distribution Services Information Disclosure) Determination 2012 states that, before the start of each Pricing Year (which for GasNet is 1 October – 30 September), every gas distribution business must publicly disclose a pricing methodology that satisfies the following extract, taken directly from the Commerce Commission's determination, which can be downloaded in its entirety from their website at www.comcom.govt.nz/gas-information-disclosure. Any uncertainty regarding the terms used in the extract or its context may be able to be resolved by referring to the source document.

2.4 PRICING AND RELATED INFORMATION

Disclosure of pricing methodologies

2.4.1 Every GDB must publicly disclose, before the start of each pricing year, a pricing methodology which-

- *(1) Describes the methodology, in accordance with clause 2.4.3, used to calculate the prices payable or to be payable;*
- *(2) Describes any changes in prices and target revenues;*
- *(3) Explains, in accordance with clause 2.4.5, the approach taken with respect to pricing in non-standard contracts;*
- *(4) Explains whether, and if so how, the GDB 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 GDB has not sought the views of consumers, the reasons for not doing so must be disclosed.*

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.

2.4.3 Every disclosure under clause 2.4.1 must-

- *(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;*
- *(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;*
- *(3) State the target revenue expected to be collected for the pricing year to which the pricing methodology applies;*
- *(4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the GDB's provision of gas pipeline services. Disclosure must include the numerical value of each of the components;*
- *(5) State the consumer groups for whom prices have been set, and describe-*
  - *(a) the rationale for grouping consumers in this way;*
  - *(b) the method and the criteria used by the GDB to allocate consumers to each of the consumer groups;*
- *(6) 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;*
- *(7) Where applicable, describe the method used by the GDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group and the rationale for allocating it in this way;*
- *(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.*

2.4.4 Every disclosure under clause 2.4.1 must, if the GDB has a pricing strategy-

- *(1) Explain the pricing strategy for the next 5 pricing years (or as close to 5 years as the pricing strategy allows), including the current pricing year for which prices are set;*
- *(2) Explain how and why prices are expected to change as a result of the pricing strategy;*
- *(3) If the pricing strategy has changed from the preceding pricing year, identify the changes and explain the reasons for the changes.*

2.4.5 Every disclosure under clause 2.4.1 must-

- *(1) Describe the approach to setting prices for non-standard contracts, including-*
  - *(a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;*
  - *(b) how the GDB determines whether to use a non-standard contract, including any criteria used;*
  - *(c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts, and the extent to which these criteria or that methodology are consistent with the pricing principles;*
- *(2) Describe the GDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of gas pipeline 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.*

Appendix 3 – Compliance with the Price Path

The following information is provided for informative purposes to demonstrate GasNet's compliance of the Pricing Methodology and the Prices that apply from 1 October 2018 with the Commerce Commission "Gas Distribution Services Default Price-Quality Path Determination 2017".

Allowable notional revenue for the First Assessment Period (Schedule 3 of the DPP Determination)

Allowable Notional Revenue for 2018 (ANR_{2018})

$ANR_{2018} = MAR / \Delta D$

Where:

MAR ($m)	is the starting price specified in Sch 1 of the DPP Determination ($4.154m)
ΔD	is the value specified in Table 2 of Sch 3 in the DPP Determination (0.9909)

Therefore:

ANR_{2018} ($m) $ 4.192

Notional revenue for the First Assessment Period (Clause 8.4(a) of the DPP Determination)

Notional Revenue for 2018 (NR_{2018})

NR_{2018}	is the Notional Revenue for the Pricing Period ending in 2018 being equal to: $NR_{2018} = \Sigma_i P_{i,2018} \times Q_{i,2016} - (K_{2018} + V_{2018})$
$\Sigma_i P_{i,2018} \times Q_{i,2016}$	is the revenue from all Load Groups based on the 2016 quantities and the 2018 prices as calculated in the table below ($1.896m + $2.401m)
K_{2018}	is the sum of all Pass-through Costs for the Pricing Year ending in 2018 ($0.109m)
V_{2018}	is the sum of all Recoverable Costs for the Pricing Year ending in 2018 (nil)

Therefore:

NR_{2018} ($m) $ 4.188

Allowable notional revenue for the Second Assessment Period (Schedule 4 of the DPP Determination)

Allowable Notional Revenue for 2019 (ANR_{2019})

ANR_{2019}	is the Allowable Notional Revenue for the Pricing Period ending in 2019 being equal to: $ANR_{2019} = (\Sigma iPi_{,2018} \times Qi_{,2017} - (K_{2018} + V_{2018}) + (ANR_{2018} - NR_{2018}))(1 + \triangle CPI_{2019})(1 - X)$

Where:

$\Sigma_i P_{i,2018} \times Q_{i,2017}$	is the revenue from all Load Groups based on the 2017 quantities and the 2018 prices as calculated in the table below ($1.896m + $2.481m)
K_{2018}	is the sum of all Pass-through Costs for the Pricing Year ending in 2018 ($0.109m)
V_{2018}	is the sum of all Recoverable Costs for the Pricing Year ending in 2018 (nil)
ANR_{2018}	is the Allowable Notional Revenue for the Pricing Period ending in 2018 as calculated above ($4.192m)
NR_{2018}	is the Notional Revenue for the Pricing Period ending in 2018 as calculated above ($4.188m)
ΔCPI_{2019}	is the derived change in the CPI to be applied for the pricing Period ending in 2019 being equal to: $\Delta CPI_{2019} = (CPI_{Jun\ 2017} + CPI_{Sep\ 2017} + CPI_{Dec\ 2017} + CPI_{Mar\ 2018}) / CPI_{Jun\ 2016} + CPI_{Sep\ 2016} + CPI_{Dec\ 2016} + CPI_{Mar\ 2017}) - 1$

Therefore:

ΔCPI_{2019} 0.0159

ANR_{2019} ($m) $ 4.340

Notional revenue for the Second Assessment Period (Clause 8.4(a) of the DPP Determination)

Notional Revenue for 2019 (NR_{2019})

NR_{2019}	is the Notional Revenue for the Pricing Period ending in 2019 being equal to: $NR_{2019} = \Sigma_i P_{i,2019} \times Q_{i,2017} - (K_{2019} + V_{2019})$
$\Sigma_i P_{i,2019} \times Q_{i,2017}$	is the revenue from all Load Groups based on the 2017 quantities and the 2019 prices as calculated in the table below ($1.912m + $2.493m)
K_{2019}	is the sum of all Pass-through Costs for the Pricing Year ending in 2019 ($0.074m)
V_{2019}	is the sum of all Recoverable Costs for the Pricing Year ending in 2019 (nil)

Therefore:

NR_{2019} ($m) $ 4.331

Compliance with the Price Path (clause 8.3 of the DPP Determination)

Notional Revenue for each Assessment Period must not exceed the Allowable Notional Revenue for the Assessment Period, such that for the Assessment Period 1 October 2018 to 30 September 2019:

$$ANR_{2019} \geq NR_{2019}$$

Where:

ANR_{2019} is the Allowable Notional Revenue for the Pricing Period ending in 2019 as calculated above ($4.34m)

NR_{2019} is the Notional Revenue for the Pricing Period ending in 2019 as calculated above ($4.331m)

Therefore:

As Notional Revenue (NR) of $4.331 does not exceed Allowable Notional Revenue (ANR) of $4.34 the condition is satisfied

Load Group	Fixed Charges ($ per day)						
	Q_{2016}	Q_{2017}	P_{2018}	P_{2019}	$P_{2018} \times Q_{2016}$	$P_{2018} \times Q_{2017}$	$P_{2019} \times Q_{2017}$
G12	3,561,075	3,558,194	$ 0.430	$ 0.435	$ 1,531,262	$ 1,530,023	$ 1,547,814
G50	41,773	41,179	$ 1.500	$ 1.500	$ 62,660	$ 61,769	$ 61,769
G180	12,078	12,265	$ 5.160	$ 5.160	$ 62,322	$ 63,287	$ 63,287
G450	2,310	2,346	$ 40.000	$ 40.000	$ 92,400	$ 93,840	$ 93,840
G1000 (C12323)	366	365	$ 41.548	$ 40.081	$ 15,207	$ 15,165	$ 14,630
G1000 (C12329)	366	365	$ 18.119	$ 18.691	$ 6,632	$ 6,613	$ 6,822
G1000 (C12337)	366	365	$ 27.719	$ 26.057	$ 10,145	$ 10,117	$ 9,511
G1000 (C16459)	366	365	$ 14.362	$ 15.169	$ 5,256	$ 5,242	$ 5,537
G1000 (C26262)	366	365	$ 26.761	$ 25.021	$ 9,795	$ 9,768	$ 9,133
G1000 (C26444)	366	365	$ 22.099	$ 15.697	$ 8,088	$ 8,066	$ 5,729
G1000 (C26779)	366	365	$ 156.199	$ 154.798	$ 57,169	$ 57,013	$ 56,501
G1000 (C31266)	366	365	$ 52.565	$ 51.536	$ 19,239	$ 19,186	$ 18,811
G1000 (C31778)	366	365	$ 42.635	$ 51.816	$ 15,604	$ 15,562	$ 18,913
G1000 (C32121)	-	-	$ 121.610	$ 123.761	$ -	$ -	$ -
	3,620,530	3,617,269			$ 1,895,779	$ 1,895,652	$ 1,912,296
					$\Sigma_i P_{i,2018} \times Q_{i,2016}$	$\Sigma_i P_{i,2018} \times Q_{i,2017}$	$\Sigma_i P_{i,2019} \times Q_{i,2017}$

Load Group	Variable Charges ($ per GJ)						
	Q_{2016}	Q_{2017}	P_{2018}	P_{2019}	$P_{2018} \times Q_{2016}$	$P_{2018} \times Q_{2017}$	$P_{2019} \times Q_{2017}$
G12	235,697	246,423	$ 7.252	$ 7.274	$ 1,709,276	$ 1,787,062	$ 1,792,484
G50	40,294	41,295	$ 6.835	$ 6.943	$ 275,411	$ 282,250	$ 286,710
G180	70,194	68,484	$ 4.852	$ 4.881	$ 340,583	$ 332,284	$ 334,270
G450	115,674	120,577	$ 0.658	$ 0.662	$ 76,114	$ 79,339	$ 79,822
G1000 (C12323)	133,847	116,667	$ -	$ -	$ -	$ -	$ -
G1000 (C12329)	54,361	56,923	$ -	$ -	$ -	$ -	$ -
G1000 (C12337)	29,567	30,611	$ -	$ -	$ -	$ -	$ -
G1000 (C16459)	26,611	2,748	$ -	$ -	$ -	$ -	$ -
G1000 (C26262)	32,100	32,544	$ -	$ -	$ -	$ -	$ -
G1000 (C26444)	123,724	126,643	$ -	$ -	$ -	$ -	$ -
G1000 (C26779)	21,521	17,367	$ -	$ -	$ -	$ -	$ -
G1000 (C31266)	165,928	193,669	$ -	$ -	$ -	$ -	$ -
G1000 (C31778)	195,524	213,894	$ -	$ -	$ -	$ -	$ -
G1000 (C32121)	-	-	$ -	$ -	$ -	$ -	$ -
	1,245,044	1,267,846			$ 2,401,384	$ 2,480,935	$ 2,493,285
					$\Sigma_i P_{i,2018} \times Q_{i,2016}$	$\Sigma_i P_{i,2018} \times Q_{i,2017}$	$\Sigma_i P_{i,2019} \times Q_{i,2017}$

Appendix 4 - Director Certification

(Pursuant to the Gas Distribution Information Disclosure Determination 2012)

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

Clause 2.9.2

We, Matthew James Doyle, and

DAVID ANTHONY RAE, being directors of GasNet Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

(a) the following attached information of GasNet Limited prepared for the purposes of clause 2.4.1 of the Gas Distribution 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.

Matthew Doyle

Director

D A Rae

Director

23. July. 2018

Date