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Default price-quality paths for gas pipeline businesses from 1 October 2017 to 30 September 2022

Draft Reasons Paper

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Associated documents

Publication date	Reference	Title
28 February 2013	ISBN 878-1-869452-20-9	Setting default price-quality paths for suppliers of gas pipeline services
28 February 2013	ISBN 978-1-869453-11-4	[2013] NZCC 4 Gas Distribution Services Default Price-Quality Path Determination 2013
27 March 2014	ISBN 978-1-869453-60-2	[2013] NZCC 5 Gas Transmission Services Default Price-Quality Path Determination 2013 (consolidating all amendments as of 26 March 2014)
29 February 2016	ISBN 978-1-869454-96-8	Default price-quality paths for gas pipeline services from 1 October 2017 - Process and issues paper
28 June 2016	ISBN 978-1-869455-07-1	Default price-quality paths for gas pipeline services from 1 October 2017 - Implementing matters arising from proposed input methodologies changes
1 July 2016	-	Default price-quality paths for gas pipeline services from 1 October 2017 - High level specification for the 2017 GPB reset financial model
1 July 2016	-	Default price-quality paths for gas pipeline services from 1 October 2017 - Model specification for the 2017 GPB reset financial model
30 August 2016	ISBN 978-1-869455-31-6	Default price-quality paths for gas pipeline services from 1 October 2017 Policy for setting price-paths and quality standards
20 December 2016	ISBN 978-1-869455-51-4	Input methodologies review decisions – Report on the IM review
20 December 2016	ISSN 1178-2560	Input methodologies amendments determinations 2016
10 February 2017	ISBN 978-1-869455-60-6	Gas Transmission Services Default Price-Quality Path Draft Determination 2017
10 February 2017	ISBN 978-1-869455-59-0	Gas Distribution Services Default Price-Quality Path Draft Determination 2017

Commerce Commission
Wellington, New Zealand

Contents

List of abbreviations

AMP	Asset Management Plan
ANR	Allowable notional revenue
BAU	Business-as-usual
BBAR	Building blocks allowable revenue
CCM	Critical Contingency Management
CCMR	Critical Contingency Management Report
CCO	Critical Contingency Operator
COF	Certificate of fitness
CPI	Consumer Price Index
CPP	Customised price-quality path
CPRG	Constant price revenue growth
DPP	Default price-quality paths
EDB	Electricity distribution businesses
EGWW	Electricity, Gas and Waste Water
GDB	Gas distribution businesses
GIC	Gas Industry Company
GPB	Gas pipeline businesses
GTB	Gas transmission businesses
HILP	High-impact, low probability
ICP	Installation control point
ID	Information disclosure
IM	Input methodologies
IRIS	Incremental rolling incentive scheme
LCI	Labour Cost Index
MFP	Multi-factor productivity
MGUG	Major Gas Users Group
PPI	Producers Price Index
RAB	Regulatory asset base
RfR	Risk free rate
RBNZ	Reserve Bank of New Zealand
RPO	Reasonable prudent operator
RTE	Response time to emergencies
TCSD	Term credit spread differential
TFP	Total factor productivity
WACC	Weighted average cost of capital
WAPC	Weighted average price cap

Executive summary

Purpose of this paper

X1 We are seeking your views on the default price-quality paths (**DPP**) we propose to set for gas pipeline businesses (**GPBs**) from 1 October 2017. This paper sets out our draft decisions on:

X1.1 the price-paths we propose;

X1.2 the quality standards we propose; and

X1.3 the ways in which GPBs must demonstrate compliance with the DPP.

X2 Our consultation process and details on how you can provide your views are set out in Chapter 1.

Decisions on setting the price-path

X3 Our draft decision is to reset prices on the basis of current and projected profitability. The starting prices we propose setting for each supplier is listed in Table X1. We also estimate the impact of our draft decision by comparing our proposed starting prices with those that would have been set had we rolled over current prices.

Table X1 Starting prices (net of pass-through and recoverable costs)

Supplier	Starting prices[1]	Impact of reset on price/revenue cap[2]
GasNet	$4.1m	-13%
Powerco	$45m	-16%
Vector	$43m	-23%
First Gas distribution	$20m	-26%
First Gas transmission	$113m	-16%
Industry total	**$225m**	**-18%**

[1] Maximum allowable revenue (MAR) in the first year of the regulatory period.

[2] This is the difference between Allowable Notional Revenue (ANR) (or Forecast Allowable Revenue (FAR) for transmission) in the first year of the 2017-2022 regulatory period, based on our draft assessment of current and projected profitability, and ANR or FAR in the first year of the period based on a roll-over of current prices.

X4 Our draft decision is based on our analysis of the revenue GPBs need to earn in order to cover their forecast costs over the 2017-2022 regulatory period. In the case of the gas distribution businesses (**GDBs**), we have also included forecasts of constant price revenue growth (**CPRG**). Comparing these revenues to the revenues GPBs would receive from a roll-over of current prices demonstrates why we consider it necessary to reset prices as the basis of current and projected profitability of each GPB.

X5 Table X2 below shows this comparison in present-value terms over the period.

Table X2 Estimated revenue over the regulatory period (net of pass-through and recoverable costs)

Supplier	Forecast revenue based on draft decision[3]	Forecast revenue from a roll-over[4]	Forecast over-recovery if prices rolled over[5]	% difference
GasNet	\$18m	\$20m	\$3m	-13%
Powerco	\$193m	\$228m	\$35m	-16%
Vector	\$184m	\$237m	\$53m	-23%
First Gas distribution	\$88m	\$120m	\$32m	-26%
First Gas transmission	\$494m	\$582m	\$88m	-15%
Industry total	**\$977m**	**\$1,188m**	**\$211m**	**-18%**

X6 We must also set a rate of change, relative to the consumer price index (**CPI**), by which prices increase by over the regulatory period (referred to as the ‘X-factor’). Based on our analysis of productivity in the sector, we propose setting the X-factor at 0%.

Factors influencing changes in starting prices

X7 Two major factors help explain these changes in starting prices:

X7.1 changes to our estimate of the weighted-average cost of capital (**WACC**) used to determine GPBs’ return on capital; and

X7.2 changes in operating expenditure (**opex**) forecasts, relative to the forecasts we set in 2013.

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3 Present value of MAR across the regulatory period calculated in the financial model.

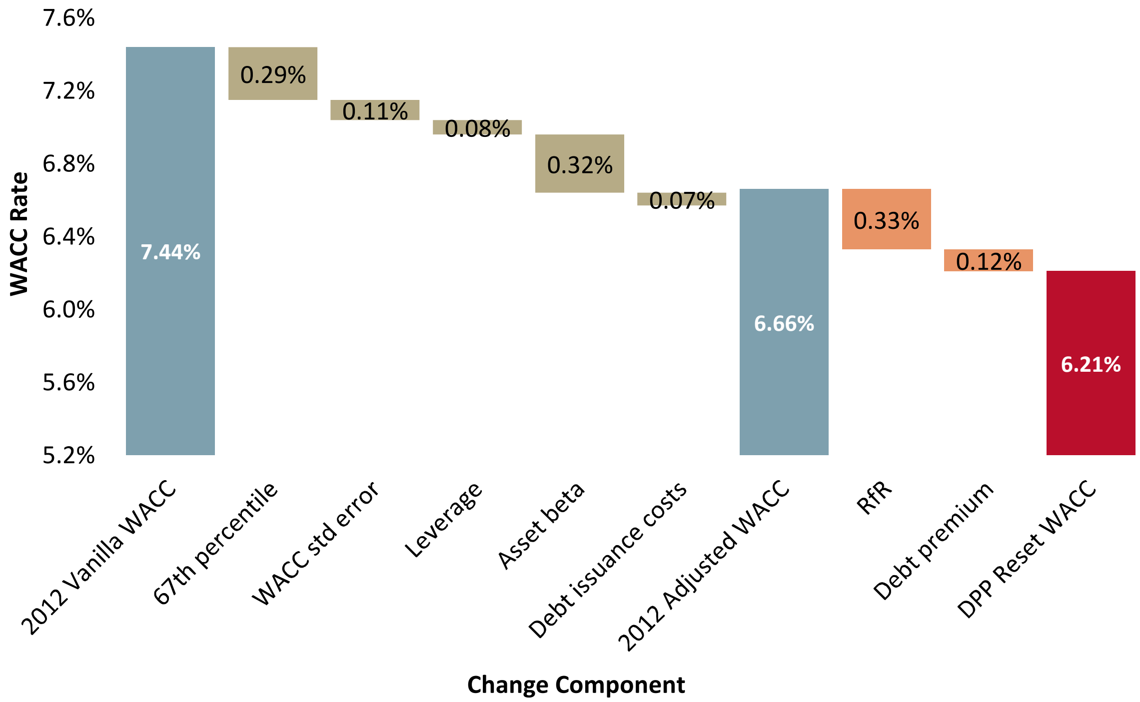
4 Simple estimate of the present value of MAR calculated by rolling current prices forward by forecast CPI and forecast changes in revenue (for GDBs only).

5 Over the regulatory period, in present value terms.

Changes to the WACC

X8 The WACC estimate we have used to set the price-path for the draft decision is 6.21%. The WACC used to set the price-path in 2013 was 7.44%. The change in WACC is due to both the Input Methodologies (**IMs**) and the parameters (the risk-free rate and the debt premium) we use to determine the WACC. These changes are set out in Figure X1.

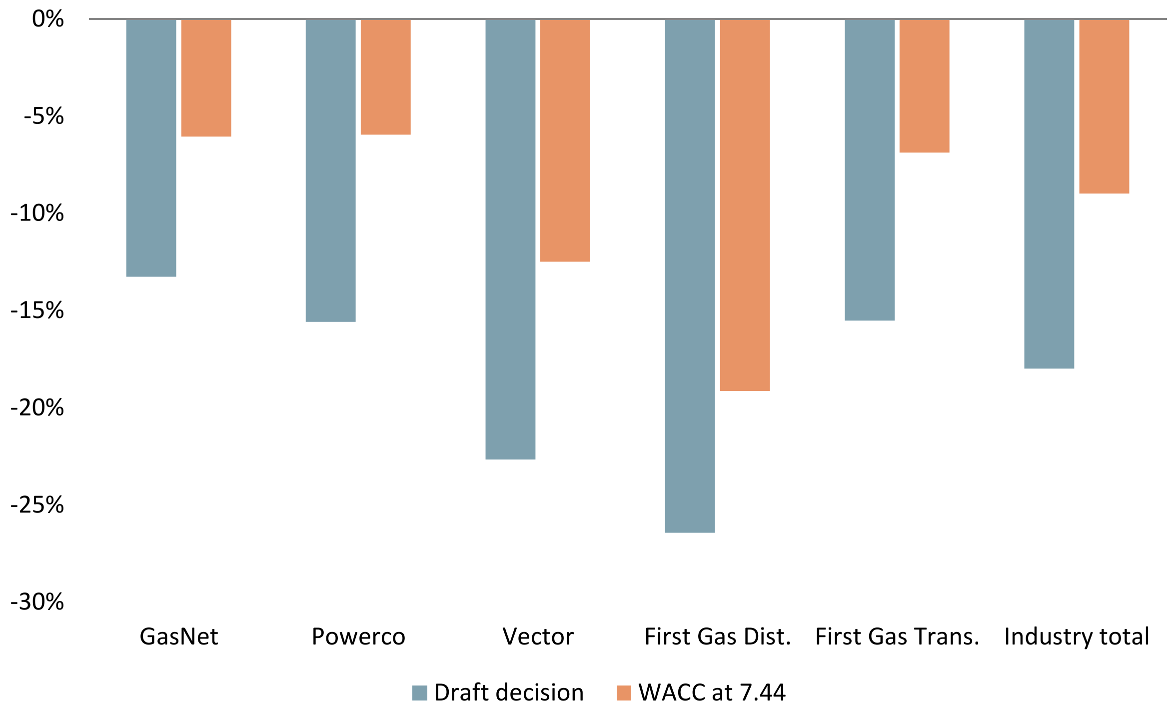
Figure X1 Cumulative effect of changes to the Vanilla WACC[6]



X9 The impact of these WACC changes on starting prices is shown in Figure X2.

[6] The policy changes shown in tan are inter-related, so the impact of each individual decision shown here does not equal the combined effect. The parameter changes in orange may change between now and the final decision. The IMs require the WACC to be determined at 1 March 2017. The figure used here is an estimate as at 1 Jan 2017.

Figure X2 Impact of reset on price/revenue cap – WACC scenarios[7]



Changes in opex forecasts

X10 Our opex forecasts for the 2017-2022 DPP are lower on average (in constant price terms) than our forecasts for the 2013-2017 DPP.

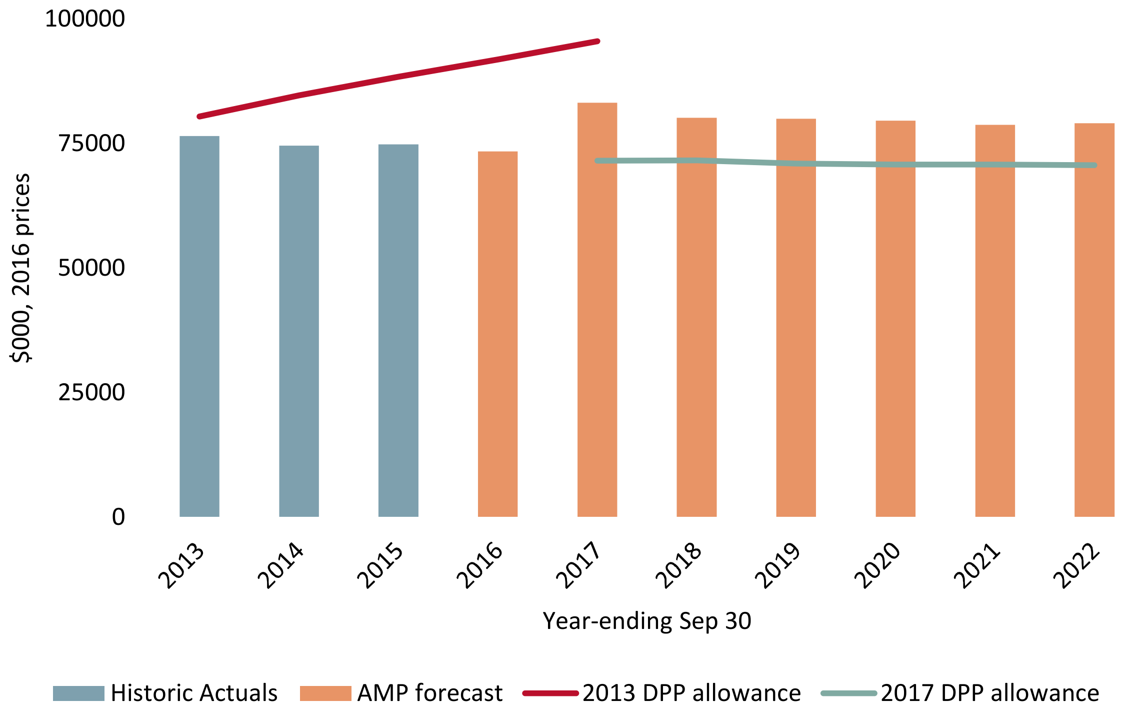
X11 In part, this is because actual historic opex (which we use as a basis for our assessment of supplier forecasts) was lower than our 2013 forecasts. In some cases it is also because our opex allowances are lower than what suppliers have forecast in their Asset Management Plans (**AMPs**).

X12 Figure X3 below presents our industry total opex forecasts (from the 2013 DPP reset and the 2017 draft DPP reset), as well as suppliers' AMP forecasts and historic actual expenditure.

X13 The step-change shown between our 2013 and 2017 forecasts is not completely representative of the impact opex has on the change between 2017/18 roll-over prices and draft reset prices. This is because supplier's price cap has moved at actual CPI, partially off-setting our 2013 over-forecast.

[7] This figure shows the difference between ANR in 2017/18 using a roll-over and our draft reset. The WACC scenario shown in green re-runs our financial model adjusting the WACC rate and cost of debt to their 2013 reset values.

Figure X3 Comparison of industry total opex forecasts



Decisions on forecasting expenditure

How we have approached forecasting expenditure

X14 In our draft decision, we have set opex and capital expenditure (**capex**) forecasts based on our assessment of GPBs' forecasts in their AMPs.

X15 We are seeking to assess whether the suppliers' forecasts reflect the efficient costs that a prudent supplier would require to meet or manage expected levels of service over both the regulatory period and the longer term, and to comply with applicable regulatory obligations.

X16 Under a DPP, we must set prices in a relatively low-cost way. This imposes limits on the type and amount of scrutiny we can undertake.

X17 To manage these limitations, we have:

X17.1 assessed the extent to which a GPB's forecast expenditure (both in aggregate and at category level) represents an increase over the GPB's historic levels of expenditure;

X17.2 engaged consultants (Strata) to provide advice on the extent to which the GPB's forecast expenditure is justified in its AMP; and

X17.3 sought additional information from GPBs where their AMPs did not sufficiently justify increases in expenditure.

X18 Where we were not able to satisfy ourselves, within the limits of low-cost scrutiny, that a supplier's forecasts represented prudent and efficient expenditure necessary to meet service standards, we replaced their forecasts with 'fall-back' forecasts based on their historic costs.

X19 Our approach to forecasting expenditure is discussed in detail in Chapter 4, and our expenditure forecasts are set out in Chapter 5. Our responses to issues raised in previous submissions on forecasting expenditure are addressed in Attachment C.

Draft capex and opex forecasts

X20 We have accepted some supplier forecasts, but in other cases we have replaced their expenditure forecasts with the fall-back forecasts. The categories of expenditure we have replaced with the fall-back forecasts are:

X20.1 GasNet's asset replacement and renewal capex;

X20.2 Vector's non-network capex, business support opex, and system operations and network support opex;

X20.3 First Gas distribution's system growth and consumer connection capex; and

X20.4 First Gas transmission's asset replacement and renewal capex, and routine and corrective maintenance and inspection opex.

X21 The resulting forecasts are set out in Table X3 below.

Table X3 Expenditure forecasts

Supplier	Opex[8]	Capex[8]
First Gas distribution	$31m	$30m
First Gas transmission	$173m	$136m
GasNet	$7m	$4m
Powerco	$73m	$60m
Vector	$50m	$76m
Industry total	**$333m**	**$305m**

[8] Present value over the regulatory period.

X22 Table X4 compares our forecasts to supplier's AMP forecasts.

Table X4 Acceptance rates of supplier forecasts

Supplier	Opex	Capex
First Gas distribution	100%	61%
First Gas transmission	93%	58%
GasNet	100%	89%
Powerco	100%	100%
Vector	96%	99%
Industry total	**95%**	**76%**

Decisions on forecasting CPRG

X23 For GDBs, in addition to forecasting expenditure, we must also forecast how revenue would grow were prices held constant, which we refer to as CPRG. This is because GDBs are subject to a weighted-average price-cap, which requires our forecast of how demand for gas distribution services will grow during the regulatory period.

X24 We do not need to forecast CPRG for gas transmission businesses (**GTBs**), as they are now subject to a pure revenue cap, which is independent of changes in demand.

X25 Our draft decision on forecasting CPRG is to use fundamentally the same approach we used in 2013, but with updates to take account of more recent information about how suppliers price, forecast demand growth at a regional level, and changes to ownership structures in the industry.[9]

X26 Our draft forecasts of CPRG are set out in Table X5. CPRG forecasts are discussed in detail in Chapter 6.

9 This includes both Vector's sale of its non-Auckland distribution assets to First Gas, and First Gas' purchase of GasNet's assets in the Bay of Plenty area.

Table X5 Forecast CPRG for GDBs[10]

Supplier	CPRG forecast
GasNet	-0.68%
Powerco	1.15%
Vector	1.67%
First Gas distribution	1.13%

Proposed standards for quality of service

X27 We must also set standards for the quality of service that GPBs must meet. We are proposing two quality standards:

X27.1 a response time to emergencies (**RTE**) standard for both GDBs and GTBs; and

X27.2 a major interruptions standard for GTBs.

X28 The RTE standard is largely the same as the standards we set in the 2013 DPP, with two changes:

X28.1 an exemption of the time allowed for GPBs to apply for failures to comply with the 180 minute RTE standard to be treated as being compliant; and

X28.2 a change to how the standard is drafted to improve clarity.

X29 The major interruptions standard is a new proposal for the 2017 DPP, and applies only to GTBs. It incorporates:

X29.1 a definition of 'major' interruptions, linked to the declaration of Critical Contingencies that lead to curtailments; and

X29.2 a reporting obligation following any interruption that meets this definition.

X30 Quality standards are discussed in detail in Chapter 7.

Demonstrating compliance with the price-quality path

X31 In addition to the substantive price and quality requirements in the DPP, we have also updated provisions relating to how suppliers demonstrate (and how we assess) compliance. These changes relate to:

X31.1 implementing the new 'pure revenue cap' form of control for GTBs;

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[10] Figures presented here are for 2017.

X31.2 improving how GDBs must demonstrate compliance with the price-path following a restructure of prices;

X31.3 how certain kinds of transactions by GDBs are treated; and

X31.4 providing greater clarity as to which provisions in the determination are price-path requirements under section 52P of the Act and which are matters of demonstrating compliance under section 53N of the Act.

X32 The implementation of the revenue cap for GTBs is discussed in detail in Attachment F. Other compliance issues are addressed in Chapter 8.

Relationship between the DPP reset and the Input Methodologies review

X33 In December 2016, we completed our statutory review of the Input Methodologies (**IMs**) that apply to GPBs. Our draft (and eventual final) decisions on the DPP are based on these new, amended IMs.

X34 The most significant change to the IMs that affects GPBs is the change in the form of control that GTBs are subject to. The details of this new 'pure revenue cap' including the revenue wash-up mechanism and the cap on the average increase in price, are included in our draft GTB determination, and are discussed in Attachment F.

X35 As discussed above, the changes to how we determine WACC (in particular the WACC percentile and the debt premium) have a significant impact on the price paths we have set.

X36 Other IMs changes are listed, along with their impacts on the DPP, in Attachment B.

Chapter 1 Introduction

Purpose of this paper

1.1 This paper sets out the draft default price-quality paths (**DPP**) that the Commission proposes to put in place from 1 October 2017 for gas transmission businesses (**GTBs**) and gas distribution businesses (**GDBs**).[11] The current DPPs for these gas pipeline businesses (**GPBs**)[12] expire on 30 September 2017.

1.2 This paper informs stakeholders about:

1.2.1 the process we are following;

1.2.2 our draft decisions relating to setting price-paths, quality standards, and compliance reporting requirements;

1.2.3 how we have arrived at these decisions, including the decision-making frameworks we have followed, and the key contextual issues that we have taken into account;

1.2.4 how we have implemented applicable decisions from the input methodologies review (**IM review**);[13] and

1.2.5 opportunities for providing submissions on our draft decision.

Structure of this paper

1.3 The chapters and attachments in this paper, and a summary of the content of each, are set out in Table 1.1 below.

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[11] Even though there is only currently one GTB (First Gas), we refer to 'GTBs' in plural for consistency with the term 'GDBs'.

[12] The term 'GPB' refers to all regulated gas suppliers: both gas distribution businesses (GDBs) and gas transmission businesses (GTBs).

[13] IM review website http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/input-methodologies-review/

Table 1.1 Structure and content of this paper

Section	Title	Content
Chapter 1	Introduction	The purpose and structure of this paper, the process for the reset, and how to provide feedback
Chapter 2	How we are guided in setting the default price-quality paths	An overview of how we set price-quality paths, our decision-making framework, and key contextual issues
Chapter 3	Resetting the price-path	The price-path we have set, and key changes from the previous DPP, including changes arising out of the IM review
Chapter 4	Our approach to forecasting expenditure	A summary of our approach to setting expenditure forecasts, and our reasons for taking this approach
Chapter 5	Our forecasts of supplier expenditure	Our draft forecasts of supplier expenditure and our consideration of additional expenditure-related adjustments to the DPPs
Chapter 6	Forecasting constant price revenue growth	Our draft decisions and an overview of how we have developed our approach to forecasting constant price revenue growth
Chapter 7	Setting standards for quality of service	Our draft decisions on setting quality standards and what we have considered in coming to these decisions
Chapter 8	Assessing compliance with the price-quality path	Our draft decisions relating to how suppliers demonstrate (and how we assess) compliance with the price-quality path
Attachment A	Key steps in the process to date	Key steps in the Gas DPP 2017 reset process before the release of this draft decision
Attachment B	Input Methodologies changes	The changes made to the IMs as part of the recent IM review which are relevant for GPBs for this reset
Attachment C	Key expenditure forecasting issues	Discussion of the key issues raised in submissions on our policy paper about our approach to forecasting expenditure
Attachment D	Expenditure forecast table	Our draft expenditure forecasts for the Gas DPP 2017 reset
Attachment E	Adjustments for changes in economies of scale	How we considered and identified gains and losses from changes in economies of scale resulting from the industry transactions involving First Gas
Attachment F	Price setting and wash-up processes for a pure revenue cap	Our draft decisions relating to the price setting and wash-up processes for the pure revenue cap form of control
Attachment G	Data and inputs to the financial model	The data used as input to the financial model, how it was sourced and what data estimations have been made
Attachment H	Step and trend model of operating expenditure	Describes the step and trend model for operating expenditure, which could be used as an alternative fall-back

Materials accompanying this paper

1.4 We have also published the following documents alongside this paper:[14]

1.4.1 proposed drafting for the GDB determination;

1.4.2 proposed drafting for the GTB DPP determination;

1.4.3 models used in determining the proposed starting prices:

1.4.3.1 the financial model, which calculates starting prices for the supplier (financial model);

1.4.3.2 the expenditure model, which forecasts suppliers' capex and opex (expenditure model);

1.4.3.3 the model used to convert real forecasts to nominal prices (expenditure reflation model);[15]

1.4.3.4 the model used to calculate the consumer price index (**CPI**) adjustment (CPI model);

1.4.3.5 the model used to forecast constant price revenue growth (**CPRG**) (CPRG model);

1.4.3.6 the input data model;[16]

1.4.3.7 information disclosure (**ID**) aggregator, which collates information from suppliers' ID submissions and responses to our section 53ZD requests (ID aggregator workbook);

1.4.3.8 a model map showing the interrelationships between the models we have used in setting the price-path;

1.4.3.9 an illustrative model demonstrating how the new revenue cap wash-up mechanism works for GTBs (form of control demonstration model).[17]

1.4.4 for each supplier we have published the following documents that support each supplier forecasting process:

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14 Available at http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

15 The expenditure reflation model takes the real series as assessed by Strata and inflates by the weighted average of the Producers Price Index and Labour Cost Index, the outputs of which are used in the financial model.

16 The input data model performs additional calculations for minor inputs to the financial model, eg term credit spread differential (TCSD), Maui Development Limited (MDL) tax and other regulated income, the outputs of which are used in the financial model.

17 This will be released during the consultation period.

1.4.4.1 Strata dashboard;[18]

1.4.4.2 Strata report – Report on supplier BAU variance checks and AMP evidence assessment;

1.4.4.3 Commission questions to each supplier following Strata report on supplier BAU variance checks and AMP evidence assessment;

1.4.4.4 supplier response to Commission questions; and

1.4.4.5 Strata report on supplier response to Commission questions – Report on supplier evidence assessment responses.

1.4.5 information received from Vector and First Gas in response to our section 53ZD requests.[19]

Process for the default price-quality path reset process to date

1.5 This paper is part of an ongoing consultation process leading up to the final DPP determinations in May 2017. As part of the DPP process, we have also been working on implementing our decisions in the IM review, published in December 2016.[20]

1.6 Attachment A sets out the key steps in the process to date.

1.7 We have appreciated the comments and submissions received on the process and issues paper, IM implementation paper, and policy paper, and at our question and answer sessions.[21] These have been considered and taken into account in our draft decisions.

Process between now and the final decisions

1.8 Table 1.2 below sets out our proposed future steps for the DPP reset.

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[18] The Strata dashboards were finalised for publication on 13 December 2016. Previous dashboard versions were used to carry out supplier BAU variance checks and AMP evidence assessments. These published dashboards are consistent with those used in the supplier forecasting assessment processes.

[19] Requests under section 53ZD of the Commerce Act 1986 were made of Vector and First Gas on 31 May 2016 to provide information relating to disaggregated information for the Vector Auckland distribution network and the First Gas non-Auckland distribution network.

[20] IM review website http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/input-methodologies-review/

[21] Documents are available at http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

Table 1.2 Process between now and final decisions

Publication/event	Intended timing
Submissions on this paper	10 March 2017
Cross submissions on this paper	24 March 2017
Published revised draft determinations for consultation	April 2017
Submissions on revised determinations	April/May 2017
Final Gas DPP determinations	31 May 2017

Technical consultation

1.9 After we have received submissions and cross submissions, we intend to publish revised draft determinations for consultation. We will seek comment from stakeholders on the draft determinations before finalising our decisions.

1.10 We expect this process to occur in April 2017.

How you can provide your views

We encourage submissions

1.11 We welcome your views on the matters raised in this paper within the timeframes set out below:

1.11.1 submissions by 5pm on 10 March 2017; and

1.11.2 cross submissions by 5pm on 24 March 2017.

1.12 By providing your views on this paper, you will help inform our final decision on the DPPs that will apply from 1 October 2017.

Address for responses

1.13 Responses should be addressed to Tricia Jennings (Project Manager, Gas DPP reset 2017) c/o regulation.branch@comcom.govt.nz.

1.14 Please include 'Gas DPP reset 2017' in the subject line of your email.

1.15 We prefer submissions in both a format suitable for word processing (such as a Microsoft Word document), and a locked format (such as a PDF) for publication on our website.

Requests for confidentiality

1.16 We encourage full disclosure of submissions so that all information can be tested in an open and transparent manner. However, we offer the following guidance where you wish to provide information in confidence.

1.17 If you include confidential material in a submission, please provide both confidential and public versions of the submission.

1.18 The responsibility for ensuring that confidential information is not included in a public version of a submission rests entirely with the party making the submission.

Chapter 2 How we are guided in setting the default price-quality paths

Purpose of this chapter

2.1 This chapter provides a brief overview of our approach to regulating price and quality in the gas pipeline sector. It provides stakeholders with an introduction to the topic, explains how we apply the relevant provisions of Part 4 (**Part 4**) of the Commerce Act 1986 (**the Act**), and explains how the specific issues discussed in each chapter fit together.

Structure of this chapter

2.2 This chapter covers the following topics:

2.2.1 the Part 4 legislative framework;

2.2.2 the economic principles that guide us in our decision-making;

2.2.3 our general decision-making framework for the DPP reset; and

2.2.4 the structure of the DPP reset.

Provisions in Part 4 of the Act relevant to our process

Legislative framework

2.3 This chapter discusses Part 4, and how it applies to the regulation of price and quality of gas pipeline services:

2.3.1 the purpose of Part 4 as described in section 52A;

2.3.2 the section 53K purpose of default/customised price-quality regulation; and

2.3.3 the section 52P, section 53M, section 53O, and section 53P requirements for setting and resetting a DPP.

2.4 The DPP we are resetting will apply from 1 October 2017 until 30 September 2022, or until a business applies for, and moves onto, a customised price-quality path (**CPP**).

Gas pipeline businesses regulated under Part 4

2.5 Table 2.1 shows the GPBs regulated under Part 4.

Table 2.1 Gas pipeline businesses regulated under Part 4

Gas distribution businesses	Gas transmission business
First Gas Limited (**First Gas distribution**)	First Gas Limited (**First Gas transmission**)[22]
GasNet Limited (**GasNet**)	
Powerco Limited (**Powerco**)	
Vector Limited (**Vector**)	

2.6 The type of price-quality regulation that applies to these businesses is 'default/customised price-quality regulation'. Under this type of regulation, we set a DPP for each business, but individual businesses may seek a CPP instead.[23]

Purpose of Part 4 of the Commerce Act

2.7 The central purpose of Part 4 of the Act is to promote the long-term benefit of consumers in markets where there is little or no competition and little or no likelihood of a substantial increase in competition.[24]

2.8 Section 52A states:

> (1) The purpose of this Part is to promote the long-term benefit of consumers in markets referred to in section 52 by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services—
>
> (a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and
>
> (b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and
>
> (c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and
>
> (d) are limited in their ability to extract excessive profits.

2.9 We promote the interests of consumers of the regulated service by promoting the section 52A(1)(a) to (d) outcomes consistent with those produced in workably competitive markets.[25] Our focus is not on replicating all the potential outcomes of workably competitive markets, but rather on specifically promoting the section 52A(1)(a) to (d) outcomes consistent with the way those outcomes are promoted in workably competitive markets.

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22 First Gas owns and operates the former Vector and Maui Development Limited transmission networks.
23 Refer to section 52B(2)(c)(i) of the Act.
24 'Competition' means 'workable or effective competition' (section 3(1) of the Act). Workable competition was explained by the High Court in *Wellington International Airport Ltd & others* v *Commerce Commission* [2013] NZHC 3289, paras 18-22.
25 *Wellington International Airport Ltd & others* v *Commerce Commission* [2013] NZHC 3289, paras 25-27.

2.10 None of the objectives are paramount and the objectives are not separate and distinct from each other or from section 52A(1) as a whole. Rather, we must balance the section 52A(1)(a) to (d) outcomes,[26] and exercise judgement in doing so. When exercising this judgement we are guided by what best promotes the long-term benefit of consumers,[27] and must not treat any of the section 52A(1)(a) to (d) outcomes as paramount.[28]

Purpose of default/customised price-quality regulation

2.11 Section 53K sets out the purpose of default/customised price-quality regulation:

> The purpose of default/customised price-quality regulation is to provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services, while allowing the opportunity for individual regulated suppliers to have alternative price-quality paths that better meet their particular circumstances.

2.12 When making the Gas DPP reset determinations, we consider that, to meet the low-cost purpose of default price-quality regulation, we must take into account the efficiency, complexity, and costs of the DPP regime as a whole.

2.13 DPPs set since the IMs were determined have adopted a combination of low-cost techniques, including information disclosed under requirements set for all suppliers, the suppliers' own forecasts, and independent forecasts.[29]

Statutory requirements for price-quality path resets

2.14 Part 4 also sets out several formal requirements and limitations on how we set DPPs. These are contained in sections 52P, 53M, 53O, and 53P, as set out in Table 2.2 below.

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[26] *Wellington International Airport Ltd & others* v *Commerce Commission* [2013] NZHC 3289, paras 684.

[27] See the discussion of our decision to adopt the 75th percentile for WACC in *Wellington International Airport Ltd & others* v *Commerce Commission* [2013] NZHC 3289, paras 1391-1492.

[28] *Wellington International Airport Ltd & others* v *Commerce Commission* [2013] NZHC 3289, para 684.

[29] Electricity Distribution Services Default Price-Quality Path Determination 2015 [2014] NZCC 33. Gas Transmission Services Default Price-Quality Path Determination 2013 [2013] NZCC 5. Gas Distribution Services Default Price-Quality Path Determination 2013 [2013] NZCC 4.

Table 2.2 Formal requirements and limitations on how we set DPPs

Section	Information provision	Requirement
Section 52P	Determinations by Commission We must make determinations under this section specifying how the relevant forms of regulation apply to suppliers of regulated goods and services	Determinations must: • Set out, for each type of regulation to which the goods or services are subject, the requirements that apply to each regulated supplier; • Set out any time frames (including the regulatory periods) that must be met or that apply; • Specify the input methodologies that apply; and • Be consistent with this Part
Section 53M	Content and timing of price-quality paths Also allows price-quality paths to include incentives for suppliers to maintain or improve their quality of supply, and allows us to prescribe quality standards in any way we consider appropriate	Sets out: • Either the maximum price or prices that may be charged by a supplier or the maximum revenues that may be recovered by the supplier;[30] • The quality standards the supplier must meet; and • The regulatory period
Section 53O	Requirements for DPP determinations	Sets out requirements for: • Starting prices; • The rate of change, relative to the CPI; • Quality standards; • The date the DPP takes effect; • The date by which any proposal for a CPP must be received; and • The date by which compliance with the DPP must be demonstrated
Section 53P	Requirements when resetting the default price-quality path	• Requires us to amend the DPP determination for the forthcoming regulatory period (in this case, the 2017-2022 period) before the end of the current regulatory period (in this case, 30 September 2017)

		• When resetting the DPP under section 53P, starting prices must not seek to recover any excessive profits made during any earlier period, and must be either:
		  • the prices that applied at the end of the preceding regulatory period; or
		  • prices that are based on the current and projected profitability of each supplier

		• The rate of change we set must be based on the long-run average productivity improvement rate achieved by either or both of suppliers in New Zealand, and suppliers in other comparable countries, of the relevant goods or services. It may take into account the effects of inflation on the inputs of suppliers of the relevant goods and services

30 Unless the context otherwise requires it, all references to supplier(s) in this paper mean supplier(s) subject to DPP/CPP regulation under Part 4.

Economic principles

2.15 When making decisions as part of resetting the DPP, three key economic principles guide us in giving effect to the purpose of Part 4. These are as follows.

2.15.1 Real financial capital maintenance (**FCM**): we provide regulated suppliers the *ex ante* expectation of earning their risk-adjusted cost of capital (a 'normal return'). This provides suppliers with the opportunity to maintain their financial capital in real terms over time frames longer than a single regulatory period. However, price-quality regulation does not guarantee a normal return over the lifetime of a regulated supplier's assets.

2.15.2 Allocation of risk: ideally, we allocate particular risks to suppliers or consumers depending on who is best placed to manage the risk, unless doing so would be inconsistent with section 52A.

2.15.3 Asymmetric consequences of over- and under-investment: we apply FCM recognising the asymmetric consequences to consumers of regulated energy services, over the long term, of under-investment (versus over-investment).

2.16 We elaborated on each of these principles, and how they should be applied in the context of price-quality regulation, in our IM review framework paper.[31]

Our approach to making decisions on the default price-quality path

2.17 For this reset, we will retain approaches from the 2013 reset where they remain fit for purpose.[32] In addition to changes required as a result of the IM review, we have considered making changes to the 2013 approaches where those changes:

2.17.1 better promote the purpose of Part 4;

2.17.2 better promote the purpose of default/customised price-quality path regulation; and

2.17.3 reduce complexity and compliance costs.

2.18 Key contextual factors driving change include:

2.18.1 implementing changes to the IMs as a result of the IM review;

2.18.2 responding to changes in the ownership structure in the gas pipeline sector;

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[31] Commerce Commission "Input methodologies review decisions: Framework for the IM review", 20 December 2016, pp. 38-49.

[32] Commerce Commission "Reasons for setting default price-quality paths for suppliers of gas pipeline services (28 February 2013).

2.18.3 where appropriate, carrying across new approaches developed during the last electricity distribution businesses (**EDB**) DPP reset; and

2.18.4 working to better co-ordinate the regulatory regimes administered by the Commission and the Gas Industry Company (**GIC**).

2.19 This paper has been prepared on the basis of the IMs as amended by our IM review decisions in December 2016.[33]

2.20 We also intend for our decisions to be compatible with other regulatory and commercial arrangements outside the Part 4 framework. To the extent possible, we have 'future-proofed' our decisions to take into account likely changes from, for example the single operating code work currently being undertaken by First Gas and GIC. However, where necessary, we have the option of reconsidering and potentially reopening the DPP after it is set to take account of legislative or regulatory change events.[34]

[33] Gas Distribution Services Input Methodologies Amendments Determination 2016 [2016] NZCC 25; Gas Transmission Services Input Methodologies Amendments Determination 2016 [2016] NZCC 26.

[34] See Gas Distribution Services Input Methodologies Amendment Determination 2016 [2016] NZCC 25, clause 4.5.2; Gas Transmission Services Input Methodologies Determination 2016 [2016] NZCC 26, clause 4.5.2; Commerce Act 1986, section 55I.

Chapter 3 Resetting the price-path

Purpose of this chapter

3.1 The purpose of this chapter is to:

3.1.1 provide a brief explanation of how we intend to set the DPP, in particular how we limit prices and revenues. It highlights the decisions we are required to make as part of this consultation process, which we seek feedback on, and the price-path features that are shaped by the legislative constraints of the Act, and the IMs that we have determined.

3.1.2 present the 'starting prices' or maximum allowable revenues that we propose for each supplier. We set out the impact of setting profitability-based starting prices compared with 'rolling over' prices or revenues from the existing DPP, and identify what elements contribute the biggest impact to the proposed adjustments.

3.1.3 address a number of price-path features that are independent to setting starting prices.

How we set a price-path

Input methodologies establish whether we limit maximum prices or revenues

3.2 The decision on whether the default price-path limits maximum prices or revenues is determined by the IMs and depends on the type of service provided.

3.2.1 Suppliers of gas distribution services will be subject to a limit on their maximum average price ('weighted average price cap').

3.2.2 Suppliers of gas transmission services will be subject to a limit on their maximum revenue ('pure revenue cap').

3.3 As part of our recent IM review, we decided to remove the option within the IMs for a weighted average price cap or a lagged revenue cap for transmission businesses, instead specifying that the form of control will be a 'pure' revenue cap with a provision to allow for a 'wash-up' for under- or over-recovery of revenue against the cap.

How we limit prices and revenues, and incentives to focus on controllable costs

3.4 The default price-paths that we set must specify maximum prices or revenues, and comprise:

3.4.1 the price or revenue limit, plus

3.4.2 allowances for pass-through costs and recoverable costs.

3.5 Setting price and revenue limits means that profitability depends on the extent to which costs are controlled. The way in which we specify price limits for distribution businesses also means that profitability depends on quantity growth (ie, connections and throughput) assumptions we make about suppliers over the regulatory period. Actual costs may differ from forecasts for a variety of reasons but the incentive to increase profits helps to put incentives on suppliers to minimise costs.

3.6 Distribution businesses also have an incentive to outperform their given demand forecast. Under a weighted average price cap distributors bear the demand risk and therefore if they are able to grow demand at a rate higher than their CPRG forecast, they are able to retain the revenue from this growth.

3.7 The costs that suppliers have little or no control over are recovered through separate allowances for 'pass-through costs' and 'recoverable costs'. The items that qualify for these categories are set out in the IMs.

The price and revenue limit setting process

3.8 For each supplier, the DPP must specify maximum price(s) or revenue for each supplier and quality standards for the regulatory period, as set out in section 53M of the Act.

3.9 The price and revenue limits are set net of pass-through costs and recoverable costs. The two main components of these price limits are:

3.9.1 the 'starting price' allowed in the first year of the regulatory period; and

3.9.2 the 'rate of change in price', or X-factor, relative to the CPI, that is allowed in later parts of the regulatory period.

3.10 The following sections briefly explain the DPP that we propose setting for each supplier. For instance, we explain how and why we propose setting starting prices based on the current and projected profitability of each supplier, rather than rolling over the supplier's existing prices. The option to choose between these two approaches is provided for under section 53P(3) of the Act.

3.11 To illustrate the effect of our choice, we estimate the following differences between forecast costs and revenues for the regulatory period if the current default price-paths were rolled over.

3.11.1 Distributors would over-recover $123 million in present value terms.

3.11.2 First Gas transmission would over-recover $88 million in present value terms.

3.11.3 This is discussed further in paragraphs 3.19 to 3.21 below.

The building blocks allowable revenue approach

3.12 The starting prices we have set for both distribution and transmission are specified in terms of maximum allowable revenue, which is an amount net of pass-through costs and recoverable costs. We calculate the maximum allowable revenue amount through two key processes.

3.12.1 Process 1: Determining a building blocks allowable revenue (**BBAR**) for each year of the regulatory period – at the simplest level the BBAR is calculated using separate cost 'building blocks' as follows:

Return on capital - Revaluations + Depreciation + Operating costs (opex) + Tax allowance

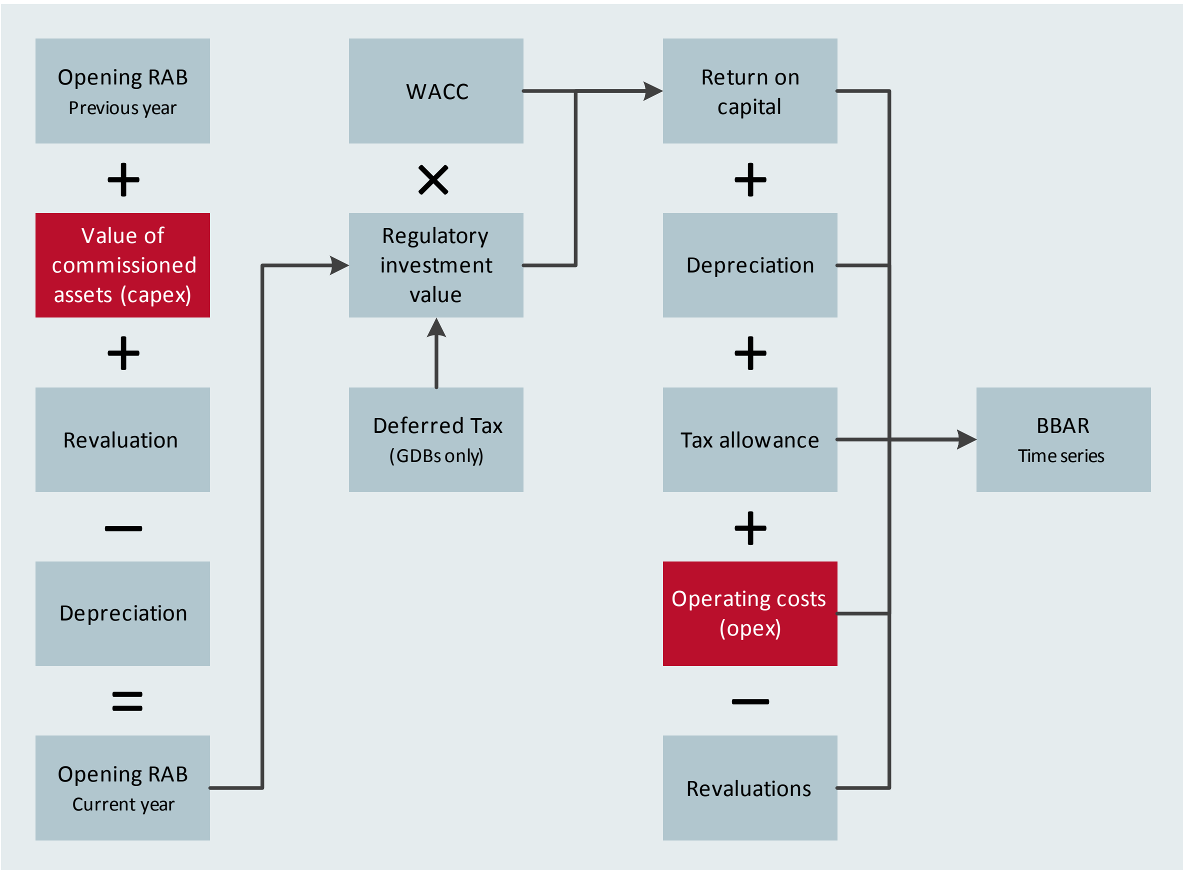
3.12.1.1 A high-level schematic is provided below in Figure 3.1.

3.12.2 Process 2: Smoothing each of the separate BBAR amounts over the regulatory period by CPI and the X-factor in present value terms, and for distribution businesses, also by the CPRG forecast. This represents the yearly changes to the price or revenue limits that are allowed over the regulatory period.

3.12.2.1 A diagram of this step is provided below in Figure 3.2.

3.12.3 We discuss how suppliers demonstrate compliance with the default price-quality paths in Chapter 8.

Figure 3.1 From RAB to BBAR



3.13 The inputs highlighted in red (capex and opex) are those which we must forecast as part of the DPP, and which are not determined by the IMs. It is for this reason the paper focusses on these elements.

3.14 Other inputs come from ID, while some are defined by the IMs, some of which are very material (eg, the WACC rate we set).

3.15 Our approach is to use forecast capital costs as a proxy for the forecast value of commissioned assets, as depicted in Figure 3.1 above.

3.16 For details of the building blocks and how they form BBAR please refer to the financial model published alongside this paper, and the model specification, published alongside the IM implementation paper.[35]

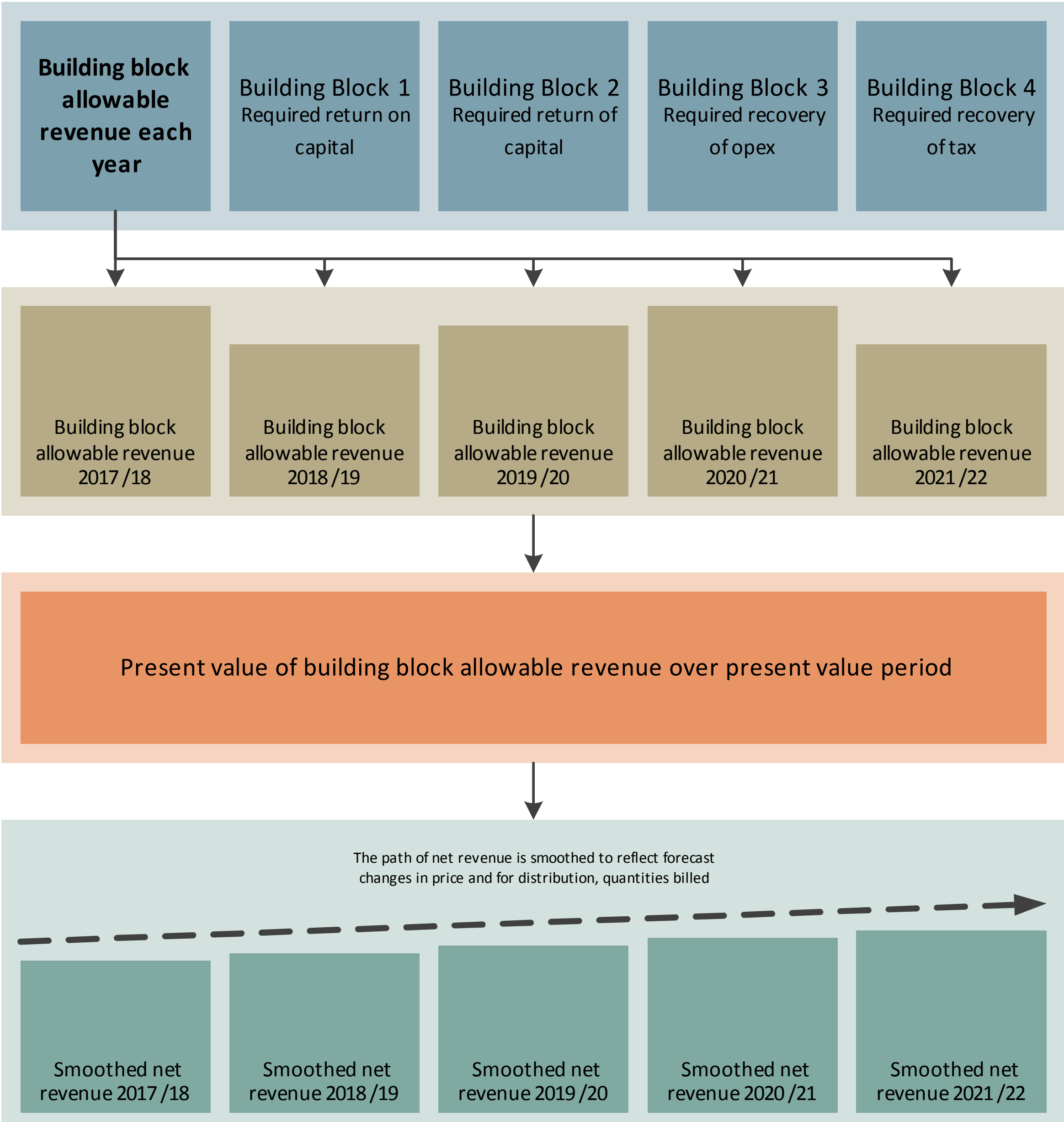
From building blocks to starting prices

3.17 These elements combine as building blocks to provide total BBAR for each year of the regulatory period. This BBAR is then smoothed into annual maximum allowable revenue figures through applying CPI and X-factor, and for distribution businesses, the CPRG forecast. Figure 3.2 below illustrates this process.

3.18 The overall present value of revenues which the regulated suppliers will be able to earn over the DPP regulatory period is unaffected by the choice of the X-factor. The X-factor will determine the timing of the maximum allowable revenues that the regulated supplier can earn over the regulatory period, but not the present value of revenues.

[35] Commerce Commission “Model specification for the GPB reset financial model” (1 July 2016).

Figure 3.2 Setting forecast revenues equal to forecast costs



Starting prices

3.19 The five-year time series of maximum allowable revenue (**MAR**) for each GPB is set out in Table 3.1. The draft starting prices are the maximum allowable revenues in the first year of the regulatory period.

Table 3.1 Maximum allowable revenue in each year of the regulatory period

Year	2017/18	2018/19	2019/20	2020/21	2021/22
GasNet	$4.1m	$4.1m	$4.1m	$4.2m	$4.3m
Powerco	$44.5m	$45.7m	$47.1m	$48.6m	$50.1m
Vector	$42.5m	$43.8m	$45.4m	$47.0m	$48.7m
First Gas distribution	$20.4m	$20.9m	$21.5m	$22.2m	$22.9m
First Gas transmission	$113.4m	$115.8m	$118.3m	$120.7m	$123.1m

3.20 Table 3.2 below illustrates the difference in starting prices between rolling over prices and resetting prices based on current and projected profitability. There is a significant drop in the prices allowed for the next DPP which indicates that if the prices were simply rolled over from the 2013 GPB DPP, the resulting prices would be excessive. This underpins our draft decision to reset prices based on current and projected profitability.

3.21 The draft starting prices, ie, MAR in the first year of the regulatory period, for each GPB are set out in Table 3.1. Table 3.2 sets out the impact of the reset on suppliers' allowable notional revenue in 2017/18.

Table 3.2 Starting prices and impact of the reset

Supplier	Starting prices[36]	Impact of reset on price/revenue cap[37]
GasNet	$4.1m	-13%
Powerco	$45m	-16%
Vector	$43m	-23%
First Gas distribution	$20m	-26%
First Gas transmission	$113m	-16%
Industry total	**$225m**	**-18%**

[36] Maximum allowable revenue (MAR) in the first year of the regulatory period.

[37] This is the difference between Allowable Notional Revenue (ANR) (or Forecast Allowable Revenue (FAR) for transmission) in the first year of the 2017-2022 regulatory period, based on our draft assessment of current and projected profitability, and ANR or FAR in the first year of the period based on a roll-over of current prices.

3.22 Table 3.3 below shows this comparison in present-value terms over the period.

Table 3.3 Estimated revenue over the regulatory period (net of pass-through and recoverable costs)

Supplier	Forecast revenue based on draft decision[38]	Forecast revenue from a roll-over[39]	Forecast over-recovery if prices rolled over[40]	% difference
GasNet	$18m	$20m	$3m	-13%
Powerco	$193m	$228m	$35m	-16%
Vector	$184m	$237m	$53m	-23%
First Gas distribution	$88m	$120m	$32m	-26%
First Gas transmission	$494m	$582m	$88m	-15%
Industry total	**$977m**	**$1,188m**	**$211m**	**-18%**

Changes between draft and final

3.23 We expect there are likely to be changes between the draft and final decision for the following reasons:

3.23.1 we will be updating certain inputs where more up-to-date information is available, eg, we will have finalised the WACC rate for the regulatory period, and Statistics New Zealand will have published another set of quarterly CPI figures;

3.23.2 further information has been requested from certain suppliers to support the expenditure in their AMPs which, when provided, may affect the expenditure allowances provided to suppliers;

3.23.3 CPRG forecasts will be updated to include supplier data from 2016 ID, where available; and

3.23.4 other changes made in response to submissions on this paper.

Drivers of starting price change

3.24 We have identified three main drivers of the starting price adjustments that we have proposed, ie, the change in MARs between regulatory periods. These are:

38 Present value of MAR across the regulatory period calculated in the financial model.

39 Simple estimate of the present value of MAR calculated by rolling current prices forward by forecast CPI and forecast changes in revenue (for GDBs only).

40 Over the regulatory period, in present value terms.

3.24.1 the expected WACC rate for the coming five years is lower than the rate that applies to the current DPPs. As discussed above, the IMs set out how we determine this rate;

3.24.2 the level of forecast operating expenditure (**opex**) and capital expenditure (**capex**) that we have accepted and proposed for each supplier; and

3.24.3 for distributors, we have forecast that CPRG will increase, on average, relative to the assumptions we made for the current default price-paths.

Reduction in WACC

3.25 The change in WACC rate has been driven by a combination of changes that we have made to the IMs, and changing input parameters and/or market conditions.

3.26 These changes are captured in Figure 3.3.

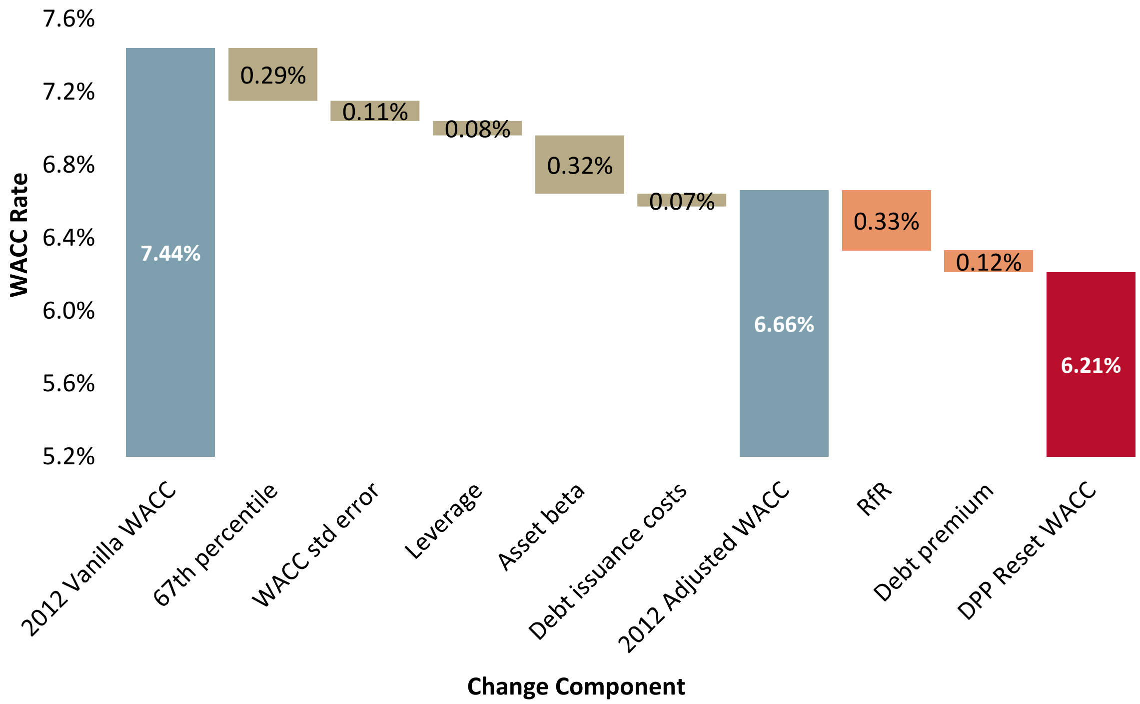
3.26.1 The left-hand side of the figure illustrates the changes that result from amendments made to IMs since the current default paths were set in 2013.

3.26.2 The right-hand side of the figure highlights the effect of market conditions on the WACC rate since 2013, chiefly the risk-free rate and debt premiums have both reduced.

3.27 The WACC rate used for the current DPPs is 7.44%. For this draft decision, we have estimated a WACC rate of 6.21% for the coming regulatory period. A final WACC rate, however, will be determined in March 2017.[41]

[41] The WACC rate we use in our calculations is a 'vanilla' (or pre-tax) rate.

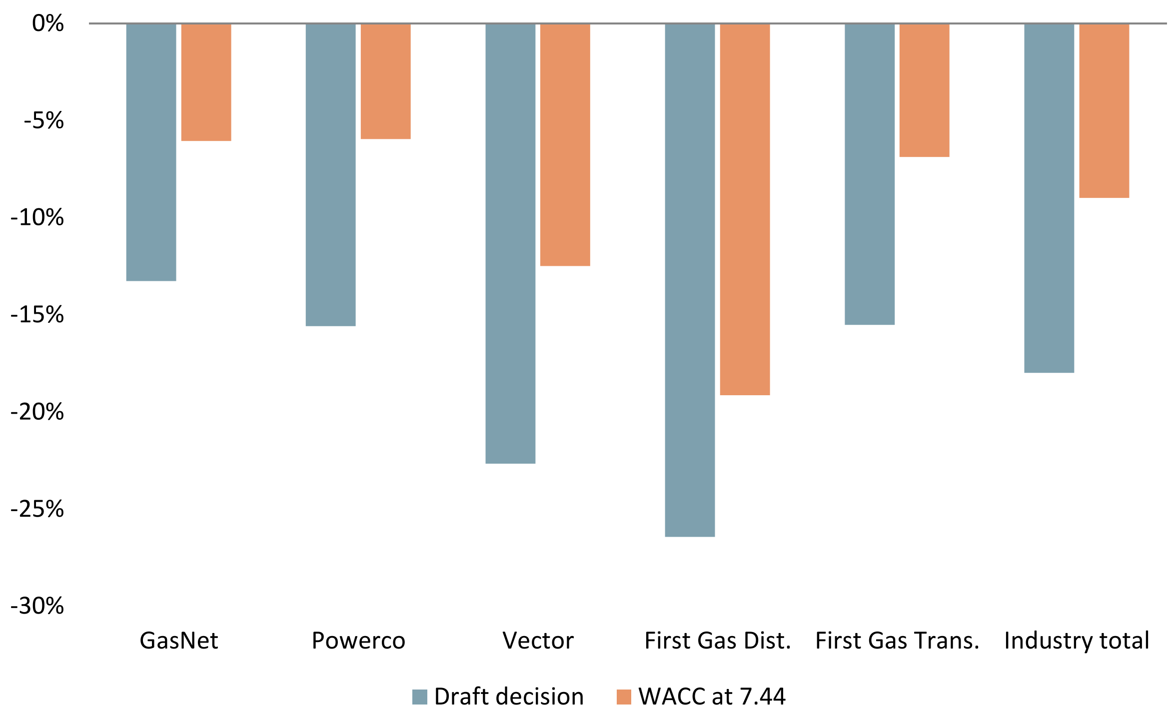
Figure 3.3 Cumulative effect of changes on Vanilla WACC[42]



3.28 Figure 3.4 highlights how changes in the WACC rate manifest into the starting price through the return on capital building block.

[42] The policy changes shown in blue are inter-related, and so the impact of each individual decision shown here does not equal the combined effect. The parameter changes in green may change between now and the final decision. The IMs require the WACC to be determined at 1 March 2017. The figure used here is an estimate as at 1 January 2017.

Figure 3.4 Impact of reset on price/revenue cap – WACC scenarios[43]



Opex and capex forecasts

3.29 Our opex forecasts for the 2017-2022 DPP are lower on average (in constant price terms) than our forecasts for the 2013-2017 DPP.

3.30 In part, this is because actual historic opex (which we use as a basis for our assessment of supplier forecasts) was lower than our 2013 forecasts. In some cases it is also because our opex allowances are lower than what suppliers have forecast in their Asset Management Plans (AMPs).

3.31 Figure 3.5 below presents our industry total opex forecasts (from the 2013 DPP reset and the 2017 draft DPP reset), as well as suppliers' AMP forecasts and historic actual expenditure.

3.32 The step-change shown between our 2013 and 2017 forecasts is not completely representative of the impact opex has on the change between 2017/18 roll-over prices and draft reset prices. This is because suppliers' price caps have moved at actual CPI, partially off-setting our 2013 over-forecast.

3.33 Our draft decision on opex forecasting is to use suppliers' forecasts as a starting point, and then to scrutinise them in order to set network and non-network opex forecasts. In the previous Gas DPP we used a step and trend methodology to inform

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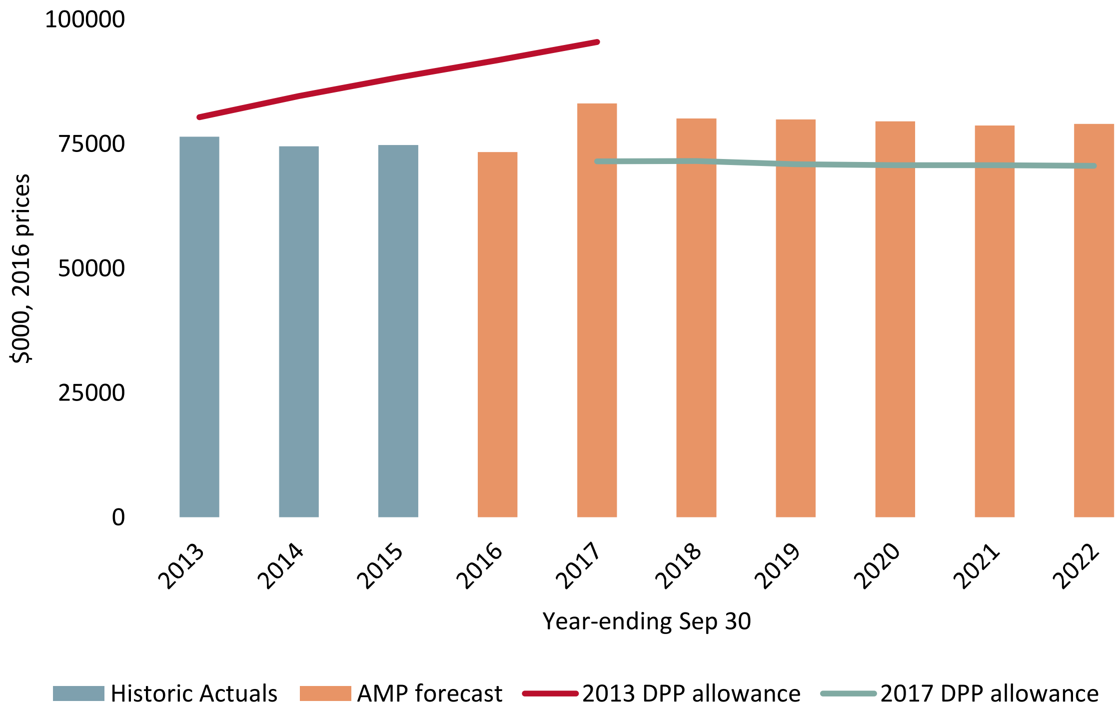
43 As in Table 3.2, this figure shows the difference between ANR in 2017/18 using a roll-over and our draft reset. The WACC scenario shown in orange re-runs our financial model adjusting the WACC rate and cost of debt to their 2013 reset values.

the opex forecast, and suppliers' AMP forecasts were capped at 120% for capex forecasts.

3.34 As outlined in Figure 3.1, opex is an independent building block, meaning every dollar of opex allowed is incremental to the BBAR. Figure 3.5 below presents our industry total opex forecasts (from the 2013 DPP reset and the 2017 draft DPP reset), as well as suppliers' AMP forecasts and historic actual expenditure.

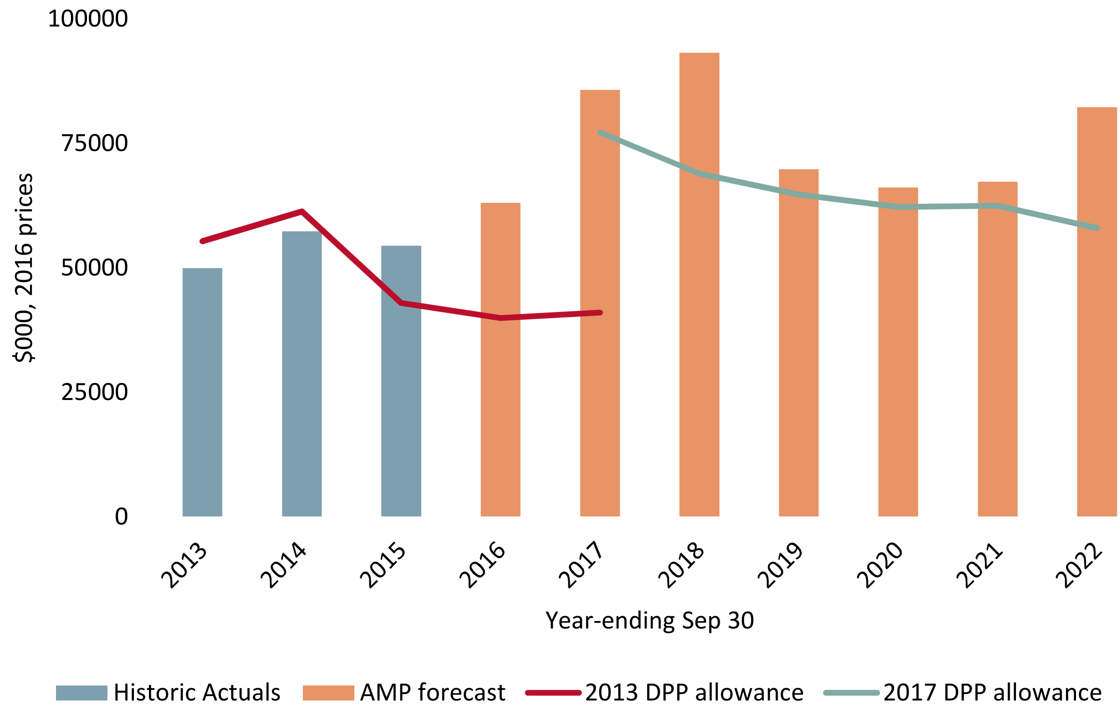
Figure 3.5 Comparison of industry total opex forecasts[44]



3.35 The capex goes into the RAB which drives both the return on capital (WACC) and return of capital (depreciation) building blocks. Figure 3.6 below presents our industry total capex forecasts (from the 2013 DPP reset and the 2017 draft DPP reset), as well as suppliers' AMP forecasts and historic actual expenditure.

[44] Values have been adjusted to move all suppliers' data to a common 30 September year-end. Values reflect the expenditure inputs used in calculating BBAR, which is why they vary year-to-year.

Figure 3.6 Comparison of industry total capex forecasts[45]



3.36 Table 3.4 outlines opex and capex average annual expenditure acceptance rates.[46] All suppliers apart from Powerco have not received the entire expenditure forecast detailed in their AMP forecasts. Only First Gas transmission received a reduction to both its opex and capex forecasts from its AMP forecasts.

Table 3.4 Opex and capex average annual expenditure acceptance rates

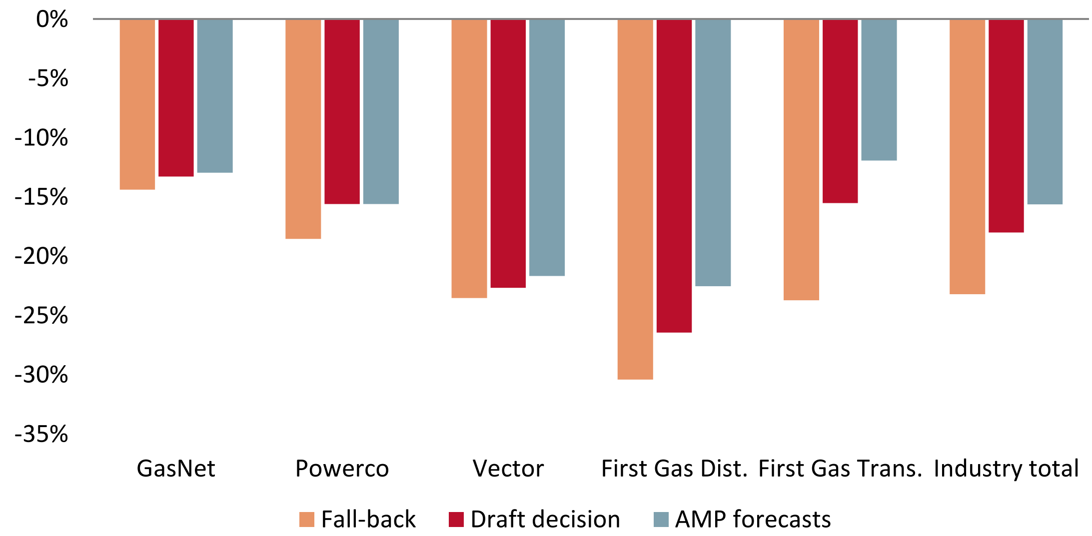
Supplier	Capex AMP expenditure acceptance rate	Opex AMP expenditure acceptance rate
GasNet	89%	100%
Powerco	100%	100%
Vector	99%	96%
First Gas distribution	61%	100%
First Gas transmission	58%	93%

3.37 The impact of these decisions on expenditure is represented in Figure 3.7 below.

[45] Values have been adjusted to move all suppliers' data to a common 30 September year-end. Values reflect the expenditure inputs used in calculating BBAR, which is why they vary year-to-year.

[46] Acceptance rate is the proportion of opex and capex proposed by the Commission relative to what suppliers submitted in their AMPs.

Figure 3.7 Impact of reset on price/revenue cap – expenditure scenarios[47]



CPRG forecasts under a weighted average price cap

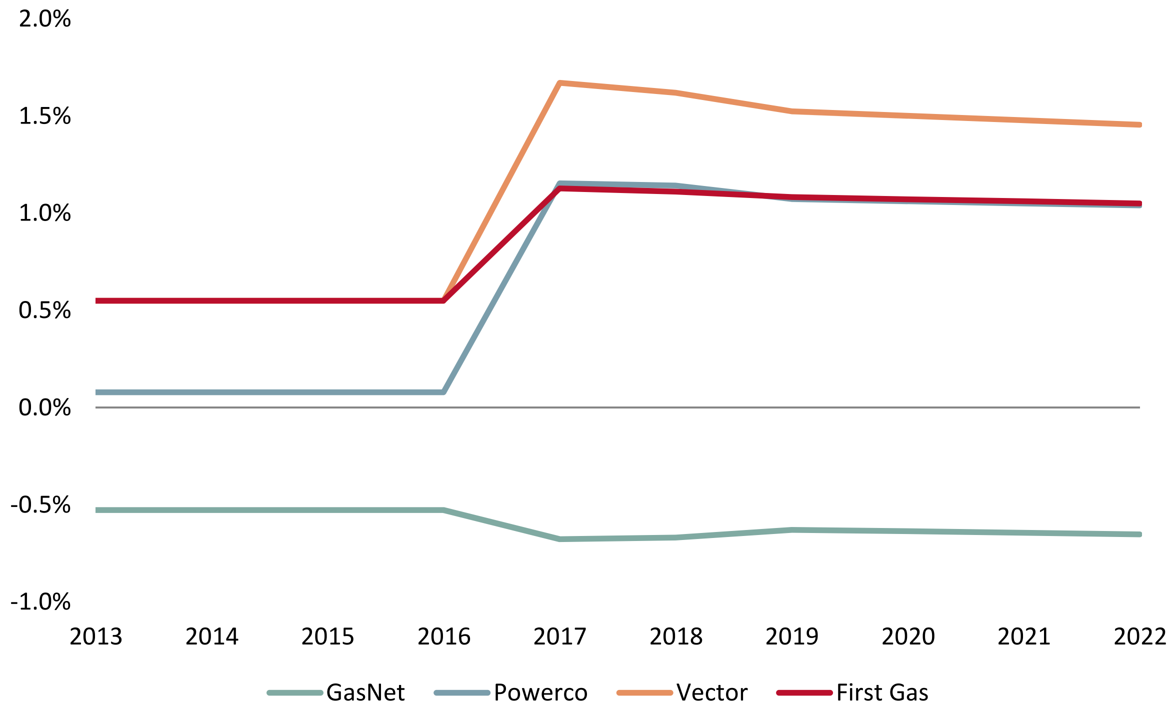
3.38 CPRG forecasts predict the rate at which revenues will grow when prices remain constant. For GDBs, under a weighted average price cap, the CPRG forecast is used to set starting prices as well as revenue growth. CPRG forecasts are used along with forecasts of inflation (**CPI**) to estimate the amount that each GDB's revenue will change throughout the regulatory period.

3.39 A higher CPRG forecast will pivot the maximum allowable revenue time series, reducing the starting price but not changing the expected MAR value in net present value (**NPV**) terms. Chapter 6 gives a detailed overview of our proposed approach to forecasting CPRG.

3.40 When the CPRG outputs are combined with other inputs into the financial model a starting price is determined for each GDB. As a guide, if CPRG forecasts were increased by 1% for each supplier under the current DPP conditions, this would result in a starting price decrease of 1.9%.

[47] As in Table 3.2, the red bars in this figure show the difference between ANR in 2017/18 using a roll-over and our draft decision. The 'fall-back' scenario in orange shows the impact of using the fall-back values for all opex and capex forecasts. The 'AMP forecast' scenario in blue shows the impact of accepting all supplier AMP forecasts.

Figure 3.8 Comparison of CPRG forecasts[48]



Other price-path considerations

Rate of change

3.41 Under the Act, we are required to consider the price changes implied for each supplier when the rate of change in price is based on the long-run rate of productivity improvement in the industry.

3.42 We have amended the method used to set the X-factor from the 2013 Gas DPP, to reflect our view that greater reliance should be placed on supplier forecasts for opex and capex. In the 2013 Gas DPP the X-factor was a component in the step and trend opex allowance calculations, but is not required under the supplier forecasting approach. In light of this we are adopting an X-factor of 0% for the draft decision, based on recent productivity studies in Australia and North America and historic evidence from New Zealand.[49]

Regulatory period

3.43 Section 53M of the Act allows for us to set a shorter regulatory period than five years if we consider that this would better meet the purposes of Part 4 of the Act, but in any event we may not set a term less than four years.

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[48] Figures for First Gas for the 2013 DPP period use the CPRG forecasts for Vector. Figures from 2017 onwards show First Gas and Vector's CPRG forecasts separately.

[49] For more discussion on the x-factor, see Commerce Commission "Default price-quality paths for gas pipeline services from 1 October 2017: Policy paper for setting price paths and quality standards" (30 August 2016) Attachment A.

3.44 We have elected to set a five-year regulatory period for the next DPP. This is a change from 2013 where a four year three month regulatory period was set.[50]

Timing assumptions

3.45 First Gas distribution and First Gas transmission have submitted AMPs with September year-ends, which are not compatible with the year-end dates of First Gas' ID data used to establish the initial conditions for the financial model. As a result of this we need to adjust the expenditure forecasts by time-shifting those three months.[51] The shorter regulatory period in the previous Gas DPP was to bring both GTBs into alignment in terms of September year-end pricing years.

[50] For the 2013 DPP we shortened the current regulatory period to align with most suppliers' pricing years. Amongst other things, this will reduce complexity in assessing compliance, and in assessing supplier performance.

[51] This has been achieved through time shifting the First Gas distribution AMP data with the formula: ID year t = $(AMP_t * 0.75) + (AMP_{t-1} * 0.25)$.

Chapter 4 Our approach to forecasting expenditure

Purpose of this chapter

4.1 This chapter explains the approach we used to forecast supplier expenditure for our draft decision for the DPP for the proposed regulatory period.

Expenditure forecasts

4.2 Our expenditure forecasts for each supplier are key inputs for determining the starting prices for the proposed regulatory period.

4.3 Our forecasts of supplier expenditure are based on the suppliers' own forecasts, which we have adjusted if, in our view, insufficient evidence has been provided to justify substantial increases. Our forecasting approach for the draft decision:

4.3.1 follows a clear and consistent series of steps;

4.3.2 is based on a core set of principles; and

4.3.3 meets broader objectives for the regulatory regime.

4.4 We have changed some of the details of this approach since the policy paper, and have made other details clearer; particularly in response to the submissions we received. We appreciate the engagement of stakeholders in their submissions, which helped with these improvements. We discuss the main issues raised in these submissions in Attachment C.

We set our approach in the context of a maturing regulatory regime

4.5 We strive to make incremental improvements in our regulatory regime over time. The areas that we have chosen to improve were partly due to the current stage of development of our regulatory regime. Our regulatory regime is in a state of transition as we move from setting the initial DPPs to making periodic resets with incremental improvements.

4.6 For the initial DPPs, the risk of systematic upward bias by suppliers to increase allowed prices/revenues was low. This low level of risk was because suppliers did not know that we were going to use some of their forecasts of expenditure to set prices/revenues when they published their expenditure forecasts.

4.7 However, under periodic resets, there is now an incentive for suppliers to bias their forecast to increase their starting price if we continue to consider supplier forecasts for resetting prices. For example, if capex forecasts for the upcoming DPP period are inflated, the resulting over-forecast would translate into an increase in the return on capital actually employed by the supplier. Incentives to inflate opex forecasts will also have a direct impact on the prices paid by consumers and the returns earned by the suppliers.

4.8 We signalled as early as the mid-period reset of EDB DPPs in 2012 that our approach to forecasting expenditure for setting DPPs should consider this incentive. Suppliers have also acknowledged this incentive.[52] Our approach to limiting this problem in the initial GPB DPPs would partially continue this incentive if used repeatedly over multiple resets.[53]

4.9 This GPB DPP reset includes the next round of incremental improvements to expenditure forecasting that address the incentives for suppliers to bias their expenditure forecasts. For this reset, we have:

4.9.1 developed principles that we believe will be reasonably stable over multiple DPP resets;

4.9.2 developed an expenditure forecasting process to implement the principles that could be considered for future resets; and

4.9.3 implemented this process with specific conditions and parameters that we think are appropriate for this reset.

4.10 The specific methods used for each forecasting step and the parameters that we have applied for this reset align with the current stage of the regulatory regime and the current context of the GPB sector. We may use a similar approach in future DPP resets, but would assess whether the specific methods and parameters were fit for purpose for that particular reset.[54] We will likely conduct analysis of supplier performance during the proposed regulatory period to inform any methods and parameters to be used in future resets.

4.11 The principles and our implementation of them for this reset have enabled us to make greater use of the suppliers' own forecasts, without an excessive risk of accepting forecasts with upward bias.

Expenditure forecasting steps

4.12 We have developed a series of steps for forecasting expenditure that applies to all GPBs based on the principles outlined in paragraphs 4.64 to 4.91. Figure 4.1 shows these steps.

4.13 In following these steps, we categorise the expenditure forecast by suppliers as either ‘supported’ or ‘unsupported’. ‘Supported expenditure’ is accepted and included at that level in our forecast. For areas of ‘unsupported expenditure’, we

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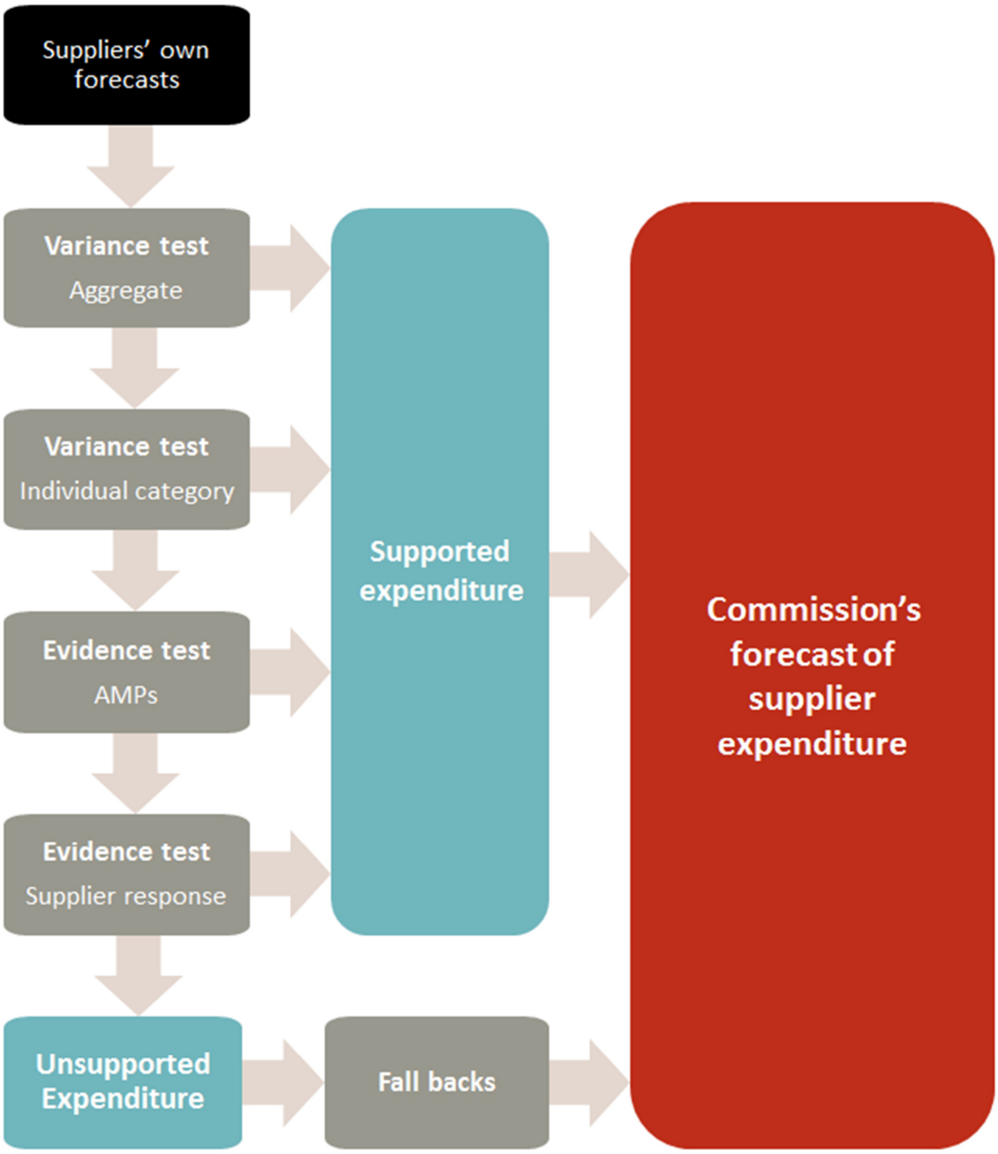
52 Commerce Commission "Resetting the 2010–15 Default Price-Quality Paths for 16 Electricity Distributors" (30 November 2012) page 67; Powerco "Revised Draft Reset of the 2010–15 Default Price-Quality Paths” [submission] (1 October 2012) page 12.

53 In the initial GPB DPP we applied a 20% cap to historic average capex.

54 For example, we could use different levels of variance in future resets for the variance tests described in paras 4.16 to 4.28.

forecast an amount using the fall-back methods described in paragraphs 4.43 to 4.58.

Figure 4.1 Expenditure forecasting steps



4.14 The starting point for our forecasting is suppliers' own forecasts.[55] Each supplier's forecast provides a good starting point because suppliers have access to the best information on:

4.14.1 current and future demand drivers for its services;

4.14.2 how to efficiently meet demand for its services;

[55] Where the end dates of each year of data from ID are different to the year-end dates used in the DPP, we have made necessary adjustments. These adjustments can be seen in the financial model, which has been published alongside the draft reasons paper.

4.14.3 the health of the assets that provide its services; and

4.14.4 the costs incurred in maintaining and operating the assets.

4.15 The sections below explain the sequential steps that we apply to the suppliers' forecasts to make our own forecast of expenditure.

We accepted supplier forecasts that are less than a 5% or 10% increase (variance tests)

4.16 Our first step in forecasting expenditure was to compare each supplier's forecast annual expenditure against historic levels of expenditure. For the draft decision, we have applied variance test levels of a 5% increase for opex and a 10% increase for capex for aggregate and individual areas of expenditure.

4.17 For each supplier, we accepted any year of their forecast aggregate opex or forecast aggregate capex as ‘supported expenditure’ if it is not more than the variance test level, ie, 5% or 10% (respectively) above the historic annual average in comparable real prices.

4.18 For suppliers with forecast aggregate opex or forecast aggregate capex above the variance test level, we considered those years of expenditure on an individual expenditure category basis. On this basis, we accepted any years of individual categories of expenditure as ‘supported expenditure’ if they were not greater than the annual variance test level.

4.19 For the categories of expenditure that we did not accept for some individual years because they are above the variance test levels, we apply more detailed tailoring using the evidence tests described in paragraphs 4.29 to 4.42 to those years.

4.20 In our judgement the variance levels of +5% for opex and +10% for capex strike an appropriate balance between:

4.20.1 identifying areas that require further evidence;

4.20.2 remaining relatively low-cost for setting the DPP; and

4.20.3 recognising the potential reasonable variation in expenditure over time.

4.21 However, we welcome feedback on these levels in submissions on our draft decision and we will reconsider the levels in our final decision.

4.22 It is appropriate for the variance test level to be higher for capex than for opex because capex is more volatile. The volatility of capex—typically due to commissioning of large one-off projects—means that it is more likely that capex would exceed a given variance test than opex would.

4.23 It is also appropriate for the variance test level to be higher for capex than for opex because the impact on consumers of excessively high capex forecasts may be less than for opex.

Calculation of historic baselines

4.24 For the aggregate and individual expenditure category variance tests, we compared a multi-year annual average of historic expenditure against annual expenditure forecasts for the proposed regulatory period.[56] For each supplier, we used three years of historic expenditure data as published by suppliers under our ID regime (2013–2015).

4.25 However, we estimated some of the historic baselines because of the First Gas industry transactions. For First Gas transmission, we estimated the historic baseline by summing the historic expenditure data of the Vector and Maui Development Limited (**MDL**) transmission businesses. For the Vector and First Gas distribution businesses, we had to apportion the historic Vector distribution expenditure into the parts of the network now owned separately by Vector and First Gas.

4.26 We estimated the proportion by taking into account the split reported by First Gas and Vector between opex and capex for 2015 and the split between the two businesses at individual expenditure category levels in their 2016–2018 expenditure forecasts.[57]

4.27 For our final decision we will have a further year of historic expenditure data available for all GPBs except for the part of First Gas transmission that was purchased from MDL. This data was required to be published under our ID regime by 16 January 2017, but this was too late to be used in making our draft decision.[58] However, we currently intend to use this new information to calculate updated three-year historic annual averages to use in the variance test for our final decision. We also intend to use the additional year of data to refine how we apportion the historic Vector distribution expenditure between the networks now owned separately by Vector and First Gas.

Individual categories of expenditure

4.28 The individual categories of expenditure are the categories used in our ID regime and are shown in Table 4.1.

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[56] We compared the expenditure in real terms (in 2016 prices) rather than nominal to account for inflationary effects. For the draft decision, we created the real time series of historic expenditure by inflating the historic nominal expenditure by the Statistics New Zealand CPI.

[57] The hypothetical split of capex and opex between the two networks was provided by Vector distribution and First Gas in their responses to our section 53ZD request for information, which has been published on our website alongside this draft reasons paper.

[58] Powerco is not required to publish its ID until 31 March 2017, but have voluntarily agreed to provide it to us earlier to be used in the final decision.

Table 4.1 Individual categories of expenditure

Gas transmission		Gas distribution	
Opex	**Capex**	**Opex**	**Capex**
Service interruptions, incidents and emergencies	Expenditure on non-network assets	Service interruptions, incidents and emergencies	Expenditure on non-network assets
Routine and corrective maintenance and inspection	Consumer connections	Routine and corrective maintenance and inspection	Consumer connections System growth
Asset replacement and renewal	System growth	Asset replacement and renewal	Asset replacement and renewal
System operations support	Asset replacement and renewal	System operations and network support	Asset relocations
Network support	Asset relocations	Business support	Total reliability, safety and environment
Business support	Total reliability, safety and environment		
Compressor fuel			
Land management and associated activity			

We have accepted expenditure that is supported by evidence (evidence tests)

4.29 We engaged Strata as consulting engineers to help us scrutinise evidence for the areas of expenditure that we did not accept under the variance test. This scrutiny of evidence is what we have called the AMP evidence and supplier evidence steps of our forecasting process. Strata made recommendations to us on whether there were reasonable explanations for expenditure. We considered Strata's recommendations for each supplier, at each step. We then accepted or rejected them before progressing to the next step of our expenditure forecasting process.

4.30 We set the expenditure objective as the basis for considering the reasonableness of explanations for expenditure:

> Capital and operating expenditure should reflect the efficient costs that a prudent supplier would require to meet or manage the expected demand at the appropriate service standards in the regulatory period and over the longer term and comply with applicable regulatory obligations.

4.31 This expenditure objective is the same as the expenditure objective used for assessing a CPP application. However, we applied this objective in a relatively low-cost way. We only applied the objective to an assessment of whether any significant increase in expenditure above historic levels is reasonable, rather than a more thorough assessment of whether all expenditure is prudent and efficient (as is done for a CPP application). Our expenditure objective is explained more in paragraphs 4.67 to 4.73.

Asset management plan evidence

4.32 The AMP evidence step involved performing a review of the supplier AMPs. The most relevant metrics and ratios of data from the AMPs were used to explore credible and reasonable quantitative explanations for the individual areas of expenditure that are above the upper variance level. For example, for suppliers with increasing levels of system growth expenditure, increasing forecast demand is a suitable piece of quantitative evidence.

4.33 The metrics and ratios also provided information on where to target qualitative assessment of the AMPs—that is, what sections of the AMPs to review to seek explanations of the areas of increasing expenditure.

4.34 A discussion on what metrics and ratios were used and how they were used is provided in paragraphs C30 to C41 of Attachment C, which discusses key changes from the policy paper.

4.35 We used the AMP review reports from Strata to help us judge whether to accept suppliers' forecasts. We expect the AMPs to provide sufficient explanation of the increases in expenditure based on the ID requirements. It is preferable that this demonstration of the expenditure objective (though not necessarily in those same terms) is given in the AMPs for several reasons, including that this is a lower cost option for the DPP than the supplier evidence step.

4.36 We targeted our efforts on the areas of expenditure that had the greatest variances relative to the scale of that business' aggregate opex or capex. This approach generally resulted in us accepting areas of expenditure without AMP or supplier evidence if the increase over historic levels of that area was equivalent to less than 5% of the aggregate opex for opex categories and capex for capex categories. This meant that we did not seek further AMP or supplier evidence for the less material areas of expenditure despite the expenditure being greater than the variance test.

4.37 Our level of targeting may change in the future as this is our first reset where we have applied evidence tests to supplier forecasts of expenditure. After taking submissions on this draft reasons paper into account, we will consider seeking AMP or supplier evidence for some expenditure that is above the variance test, but that we have not sought evidence for in this draft decision because of its relatively small scale. For future DPP resets, we anticipate that we will likely seek AMP or supplier evidence for all categories of expenditure above the variance test level.

Supplier evidence

4.38 If more supplier evidence was necessary because the AMP alone did not provide a reasonable explanation of the expenditure increase, we asked for this evidence from the suppliers. It was voluntary for the suppliers to respond, and had they not responded we would have forecast those areas of expenditure at the fall-back levels described in paragraphs 4.43 to 4.58.

4.39 We expected that the necessary information should already exist and could have been in the form of existing documents, or a specific response to the questions. We sought information that specifically addressed the area of expenditure concerned—information on the overall governance and expenditure decision-making processes was not sufficient on its own.

4.40 We consciously placed the onus on the supplier to provide the information it considered supported its forecasting. We consider that a flexible, supplier-driven approach is most appropriate for a DPP. The alternative, which is that we prescribe information requirements (as is the case under a CPP), may have resulted in an unnecessarily long list that accommodated multiple potential scenarios and increased compliance costs.

4.41 Strata reviewed the supplier responses to our questions and advised us on whether there was sufficient evidence that the expenditure is likely to meet the expenditure objective. We assessed Strata's advice to help us decide whether those areas of expenditure should be accepted as 'supported expenditure'.

4.42 When forming questions for suppliers and assessing the responses, we applied greater scrutiny to areas of expenditure that are larger or have larger increases from historical levels. However, there is a limit to how much scrutiny we can apply under this DPP expenditure forecasting process, with some expenditure being more appropriate for a CPP application.

We forecast expenditure for unsupported categories of expenditure (fall-backs)

4.43 For individual areas of expenditure that are unsupported—because they failed the variance test and were not adequately supported by evidence from the AMP or the supplier—we have set the forecast expenditure at a fall-back level. The standard fall-back level is the upper bound of the variance test.

4.44 However, we have also applied two alternative fall-backs for particular situations. The step and trend model is used as an alternative fall-back level for opex categories if the standard fall-back level would make the expenditure lower than the step and trend model and if the supplier forecast was originally higher than the step and trend model.[59] We have also applied an additional fall-back for projects or programmes that were not accepted because they would be better suited for a CPP application.

4.45 The standard and alternative fall-backs are described below in paragraphs 4.46 to 4.58.

Standard fall-back: upper bound of variance test

4.46 For the draft decision, we set the standard fall-back level as the same as the upper bound of the variance test: 5% above the historic average for opex and 10% above the historic average for capex.

[59] The step and trend model for opex is described in Attachment H. We have not updated the model for this draft decision, the model was published on our website alongside our 30 August 2016 policy paper.

4.47 Our policy paper discussed several potential approaches to calculating the fall-back levels. Submissions on the policy paper generally did not provide specific feedback on the individual approaches. Instead, the key theme of the submissions was that the fall-back position should be clear and consistent and not excessively low.[60] We agree that the fall-back positions should be more clear and consistent, and expect that the draft fall-back policy will reduce uncertainty and clarify the discretion that we are applying when setting our expenditure forecasts.

Opex step and trend model as an alternative fall-back

4.48 We would not forecast the aggregate opex as lower than the step and trend model unless the supplier's own forecast is lower than the step and trend model (even if some expenditure is rejected at the supplier evidence stage). In cases where the present value of the supplier's forecast of aggregate opex over the five years of the DPP was greater than our step and trend model, we would have set the step and trend model as a minimum for our forecast.

4.49 We introduced this mechanism to our expenditure forecasting process to reduce the risk that suppliers' revenue is pushed too low. Excessively low revenue could result in CPP applications when the additional cost of a CPP may not be warranted.

4.50 For further discussion on our step-and-tend approach, please refer to Attachment H.

Alternative fall-back for expenditure that is inappropriate for forecasting under a DPP

4.51 The CPP fall-back acknowledges that if we do not accept expenditure forecasts from suppliers because they represent projects or programmes that should be considered in a CPP application, then the implication is that we are forecasting that the supplier will make a CPP application. Therefore, it is appropriate to include the cost of a CPP application in our forecast of expenditure. This policy serves the long-term interest of consumers by allowing funding for a CPP application.

4.52 We applied a CPP fall-back to suppliers that had forecast projects or programmes that we considered to be inappropriate for forecasting under a DPP but that we considered are reasonably likely to progress to a CPP application. Projects or programmes may be inappropriate for forecasting under a DPP because the uncertainty and impact on price or quality suggests the expenditure requires a level of scrutiny that cannot be applied under a low-cost DPP process.

4.53 We set the CPP fall-back amount lower than the full estimated cost, recognising that some of the CPP application costs can be recovered from consumers through a recoverable cost.

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60 For example, Orion "Submission on Gas DPP reset 2017 Policy paper" (28 September 2016) para 29.7; and GasNet "Submission on Gas Pipeline Services 2017 DPP policy paper" (28 September 2016) paras 27–28.

4.54 We applied the CPP fall-back at a project or programme level, so any remainder of the area of expenditure was assessed following the standard forecasting steps if the cost of the CPP-suited project or programme is individually identifiable. We then either accepted the remaining expenditure as forecast by the supplier, or forecast the expenditure at the standard fall-back level. The CPP fall-back was applied in addition to the accepted remaining expenditure or the standard fall-back.

4.55 We apply the CPP fall-back as opex, regardless of whether the project or programme (that is judged to be more appropriate for a CPP) was capex or opex. This categorisation is because the costs involved in producing a CPP application are most likely to be opex rather than capex.

4.56 Including the CPP fall-back in our forecast of opex rather than extending the CPP recoverable cost term means that suppliers will face incentives to reduce costs.

4.57 If the supplier's forecast expenditure for that area minus the forecast cost of the CPP project was lower than the variance test, the fall-back position would have been the supplier's forecast expenditure less the forecast cost of the CPP project, plus the CPP fall-back.

4.58 We will only apply a maximum of one CPP fall-back for each supplier for the proposed regulatory period. If a supplier with a CPP fall-back does not make a CPP application during the period, we do not intend to allow compensation for the costs of applying for a CPP again in future regulatory periods.

We adjusted our expenditure forecasts to account for industry transactions

4.59 In the 2010 IM reasons paper, we stated that suppliers are able to temporarily retain cost reductions caused by efficiencies that result from a merger or acquisition during the regulatory period following the transaction. Consumers will then benefit from the cost reductions during the regulatory period after that.[61]

4.60 Consistent with this, we consider that the suppliers should temporarily retain the cost of any forecast inefficiencies resulting from industry transactions (such as the split of the Vector distribution network) for the regulatory period following the transaction. Consumers would then bear the costs in the regulatory periods after that.[62]

4.61 To implement this for the draft decision, we have considered whether our forecasts of expenditure include any increase or decrease in expenditure that is a result of a gain or loss of economies of scale. If any forecast efficiency gains or losses due to the industry transactions are included the suppliers' expenditure forecasts, the gains or losses would be passed on to consumers rather than impact the supplier's

[61] Commerce Commission "EDB GPB Input Methodologies Reasons Paper" (December 2010) page 80.

[62] For the First Gas, Vector, and MDL transactions—which occurred in 2016—the suppliers will bear any costs of the changes in the proposed regulatory period, and consumers will bear the costs thereafter.

profitability were it not for an explicit adjustment. Therefore for our expenditure forecasts used for the proposed regulatory period, we have:

4.61.1 added back any economy of scale gain to the expenditure forecast; and

4.61.2 subtracted any economy of scale loss from the expenditure forecast.[63]

4.62 Vector submitted on our policy paper that we should take a consistent approach between efficiencies and inefficiencies caused by economies of scale and diseconomies of scale.[64] We agree with this. However, Vector argued this on the basis that we should not make adjustments for either increased or decreased expenditure.

We did not provide additional allowances to reduce the likelihood of a CPP application

4.63 Unlike our 2013 reset of the gas pipeline DPPs, we have not provided any additional allowances due to the uncertainty of expenditure forecasts. The supplier scrutiny approach to forecasting expenditure that we have applied in this reset allows for sufficient tailoring of suppliers' specific circumstances to make providing additional allowances unnecessary.

Principles that underpin our approach to forecasting expenditure

4.64 The foundation of our approach to forecasting is to best promote the purpose of Part 4 of the Act within the relatively low-cost DPP framework set out in section 53K of the Act. Within Part 4 of the Act and the IMs, there remains significant discretion for how we set DPPs and CPPs. To guide our decision-making when exercising this discretion, we have applied a set of principles.

4.64.1 *Expenditure objective*—the expenditure forecasts we set should reflect an explicit expenditure objective that suppliers are being assessed against;

4.64.2 *Low-cost DPP*—we must set DPPs in a relatively low-cost way;

4.64.3 *Tailoring*—a greater level of tailoring in the way we set DPPs can help better promote the long-term benefits of consumers; and

4.64.4 *Proportionate scrutiny*—the level of scrutiny we apply when determining suppliers' expenditure forecasts should be proportionate to the price and quality impact on consumers.

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63 Making adjustments for industry transactions means that our expenditure forecasts are not our true best forecasts but the adjustments are appropriate as described in paras 4.59 to 4.62.

64 Vector "Submission to Commerce Commission on gas pipeline business default price path reset" (28 September 2016) paras 43 to 49.

4.65 These principles have been developed and refined over the course of consultation with stakeholders across both the DPP and on the review of the CPP IMs.[65] These principles are key to understanding why we have forecast expenditure using the approach set out in this chapter.

4.66 Each of the principles, along with stakeholder submissions on them, is discussed below.

Expenditure objective

4.67 The expenditure objective we have chosen to use is the same as the objective applied when assessing a CPP. Specifically:

> Capital and operating expenditure should reflect the efficient costs that a prudent supplier would require to meet or manage the expected demand at the appropriate service standards in the regulatory period and over the longer term and comply with applicable regulatory obligations.

4.68 Establishing an overarching objective that guides our assessment of suppliers' expenditure forecasts is important. In a process that requires us to exercise judgement, an expenditure objective helps to guide our assessment, and gives suppliers and consumers a degree of certainty. In particular, an expenditure objective is a reference point to justify potential adjustments to suppliers' expenditure forecasts.

4.69 Aligning the expenditure objective of this DPP assessment framework with the CPP equivalent is appropriate because, in principle, DPPs and CPPs have the same objective. They are both about delivering long-term benefits to consumers through price-paths derived from expenditure allowances that reflect the following:

4.69.1 right investments (consideration of alternatives);

4.69.2 right timing (not in advance or deferred);

4.69.3 right cost (tendering processes, unit costs etc); and

4.69.4 right resources to deliver (delivery plan).

4.70 The outcome we are seeking to promote with this expenditure objective remains the same in a DPP and in a CPP. What differs is:

4.70.1 the level of scrutiny we apply to test expenditure against the objective;

4.70.2 the level of assurance we require as a result of this process; and

4.70.3 the level of departure from a business-as-usual level of expenditure we are willing to accept, as a result of these first two points.

65 The final IM review decisions relating to CPP requirements are described in Commerce Commission "Input methodologies review decisions—Topic paper 2: CPP requirements" (20 December 2016).

4.71 These differences are crucial, and have a material impact on the type of process we implement. Many submissions focused on the similarity of the objectives, while overlooking these differences.[66]

4.72 First Gas, in its cross submission, rightly identified this issue:[67]

> In our view, the Commission is right to say that the DPP and CPP can have the same goal but use different methods to achieve that goal. We suspect that the concerns raised by suppliers about the expenditure objective relate more to how the Commission gains comfort that supplier forecasts are prudent and efficient (concerns that we share), rather than the objective itself.

4.73 We agree with MGUG's view that:[68]

> A flexible approach might suggest a potential for regulatory scope creep of inquiry to suppliers. We don't see this as likely. A strong philosophy is more effective than prescription in ensuring good consumer outcomes. The Commission should have the flexibility to request a range of responses to satisfy itself on a particular issue of a forecast. To the extent that this might amount to no more than a phone call or an email to clarify we consider this as consistent with a low cost approach.

We set the default price-quality paths in a relatively low-cost way

4.74 We must design and implement the DPP (including our approach to forecasting expenditure) in a way that is relatively low-cost, while allowing for a more tailored CPP, as required by section 53K of the Act. This includes both direct costs to the Commission, and the costs imposed on suppliers and consumers.

4.75 Our process for forecasting expenditure for this draft decision is relatively low-cost. This is because it applies a series of incrementally more rigorous tests to supplier forecasts for areas of expenditure that require more scrutiny. Including the variance tests focuses our scrutiny on areas of suppliers' forecast expenditure that depart from historic levels.

4.76 Assessing supplier AMPs, and asking for clarification to support expenditure forecasts not described in the AMPs is a relatively low-cost way for us to be satisfied that supplier forecasts are likely to meet the expenditure objective. If suppliers are preparing their AMPs in line with the existing ID requirements, there should be little additional cost to them.

4.77 To further ensure the low-cost of the evidence steps, we limited our assessment to broad categories of expenditure. We did this rather than assessing individual projects or programmes, except when they represented a particularly significant

[66] Orion "Submission on Gas DPP policy paper" (28 September 2016), para 28; Powerco "Submission on Gas DPP policy paper" (28 September 2016), para 55; ENA "Submission on Gas DPP policy paper" (28 September 2016), para 14; Vector "Submission on Gas DPP policy paper" (28 September 2016), paras 14–15.

[67] First Gas "Cross-submission on Gas DPP policy paper" (12 October 2016), page 2.

[68] MGUG "Submission on Gas DPP policy paper" (28 September 2016), para 16.

proportion of total expenditure. Using voluntary requests for information—rather than our information request powers under section 53ZD—also reduced the cost.

4.78 The metric and ratio approach (described in paragraphs 4.32 to 4.34 and Attachment C) has allowed us to understand the cost drivers of each supplier in an efficient and low-cost way. The metrics and ratios are calculated from existing ID information and quickly highlight expenditure outliers and correlated effects.

4.79 Overall, we applied a much lower level of scrutiny (and therefore cost) in setting the DPPs than is applied in consideration of CPP applications.

4.80 If expenditure could not be supported, we forecast the levels in a relatively simple way using historic costs rather than building a bottom-up forecast. This ensured that the fall-back step of the forecasting process was relatively low-cost. This is appropriate because we have already applied an appropriate amount of scrutiny to these areas through the AMP evidence stage and the supplier evidence stage.

4.81 Because of these features, we do not agree with the objections raised in submissions that our approach is high cost and goes beyond what the Act intends in the principles we apply. We have, however, made substantive changes and clarifications to the forecasting process since the publication of our policy paper in August 2016.

Tailoring within a low-cost DPP

4.82 We consider it appropriate to tailor the forecasts we set to suppliers' individual circumstances, to the extent that it is possible to apply the level of scrutiny within a low-cost framework that is appropriate for that tailoring.

4.83 Tailoring, combined with appropriate scrutiny can promote the long-term benefit of consumers. As set out in our policy paper: [69]

4.83.1 tailoring can help ensure that price-quality paths provide for efficient investment, and can reward superior performance;

4.83.2 greater scrutiny can—at the same time—benefit consumers by reducing opportunities for upwardly biased supplier forecasts and ensuring that suppliers charge prices that are more commensurate with the level of quality demanded; and

4.83.3 CPP applications that might otherwise be necessary could be avoided.

4.84 It remains our position that these goals are worth promoting, and that, if possible, tailoring is an effective means of doing so.

[69] Commerce Commission "Default price-quality paths for gas pipeline services from 1 October 2017" (30 August 2016) para 3.38, 3.44.2, and 3.39.

4.85 In submissions, stakeholders raised concerns about the implications of greater tailoring and scrutiny. At the same time several were broadly supportive of the principle of tailoring.[70]

4.86 In particular, Powerco expressed its concerns as follows:[71]

> The primacy given to tailoring in this section of the consultation paper runs counter to the legal framework for a DPP… We consider that tailoring should be a secondary outcome, and should not be pursued 'at all costs', and certainly not to the detriment of the objectives of the DPP framework. This approach is consistent with the framework of the DPP regime, and aligns with the High Court's views in Wellington Airport v Commerce Commission…

4.87 We agree with Powerco's comment that to give tailoring primacy (in particular above promoting the Part 4 purpose and maintaining a low-cost approach) would be inconsistent with the intent of the Act. DPP tailoring is only a means to achieving the purpose of Part 4 within a relatively low-cost DPP.

4.88 We do not agree that our forecasting process gives any primacy to tailoring. As discussed in paragraphs 4.16 to 4.28, the variance tests avoid an extensive and costly process. At the same time, the AMP evidence and supplier evidence steps still allow for forecasts to be tailored if this would better promote the Part 4 purpose.

Proportionate scrutiny

4.89 Proportionate scrutiny is about applying a level of scrutiny when tailoring a price-quality path that is commensurate with the price and quality impact on consumers.

4.90 In the 'expenditure forecasting steps' that we have applied, the level of scrutiny we apply to the suppliers' forecasts is related to the scale of the expenditure. Additionally, we use the amount of scrutiny necessary to assure ourselves that the forecast expenditure is appropriate—that is, where necessary we use a process of incrementally higher levels of scrutiny if the lowest levels are insufficient.

4.91 We apply a generally similar level of scrutiny to all suppliers because while smaller suppliers have lower levels of expenditure, they also have fewer customers so the impact on individual customers may still be significant.

Regulatory objectives of our forecasting approach

4.92 Our DPP regulatory regime aims to limit suppliers from earning excessive returns, while maintaining incentives for sufficient investment and to supply services at the level of quality demanded by consumers.

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[70] Orion, "Submission on Gas DPP policy paper" (28 September 2016), para 12, Powerco "Submission on Gas DPP policy paper" (28 September 2016), para 15 and 29; First Gas "Submission on Gas DPP policy paper" (28 September 2016), page 2.

[71] Powerco "Submission on Gas DPP policy paper" (28 September 2016), paras 35–37.

Suppliers are limited in their ability to extract excessive profits

4.93 Within the constraints of setting the DPPs in a relatively low-cost way, we have applied an expenditure objective that aims to only allow for expenditure in our forecasts that is prudent and efficient.

4.94 To the extent that suppliers are able to 'beat' these expenditure forecasts through finding efficiencies, the resulting increase in profitability is not 'excessive', and will benefit consumers in the long-term when these efficiency gains are passed on. The efficiency gains will be passed on in future regulatory periods through our resets being based on a relatively lower value of assets and relatively lower opex.

4.95 On the other hand, to the extent that suppliers are able to spend less than forecast through the Commission accepting either overly optimistic or inflated expenditure forecasts, profits would be excessive. This risk is the main reason that we have applied proportionate scrutiny through the evidence tests. However, the risk of excessive profits from excessively high expenditure forecasts is limited in the same way that the regime shares benefits of efficiency gains with consumers.

Suppliers have incentives to innovate and invest

4.96 Our proposed approach promotes incentives to innovate and invest by being able to accept expenditure above historic levels except for projects or programmes that are only suitable for inclusion in a CPP. This expenditure is accepted if suppliers can demonstrate in a relatively low-cost way that the investment or expense is prudent and efficient, either in their AMPs or through supplying additional evidence.

4.97 This improves on our 2013 approach, which may not have allowed increases in expenditure above historic trends regardless of the justification for the investments or innovations.

4.98 The Electricity Networks Association (**ENA**) and Aurora are correct when they point out in their submissions that our forecasts should not represent 'stretch targets' that build in an expectation of efficiency gains before they have been made.[72]

4.99 GasNet identified this potential problem as a ‘conflation of efficiency incentives and expenditure forecasting objectives’, stating:[73]

> … the consultation material and information about the scrutiny being applied to GasNet implies the Commission and Strata are trying to use this method to set lower expenditure allowances to drive efficiencies.

4.100 We do not consider that the approach we are proposing does this, particularly because we use suppliers' own forecasts.

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72 ENA "Submission on Gas DPP policy paper" (28 September 2016), para 17; Aurora "Cross-submission on Gas DPP policy paper" (12 October 2016), p. 3.

73 GasNet ENA "Submission on Gas DPP policy paper" (28 September 2016), para 22.

4.101 Without appropriate scrutiny, this approach to price-quality paths could lead to forecasts being inflated above what is prudent and efficient, to increase profitability. To mitigate this risk, our approach incorporates proportionate, low-cost scrutiny of suppliers' forecasts.

4.102 Submissions on our policy paper generally acknowledged the need for scrutiny,[74] although as noted in paragraphs 4.74 to 4.91, many submitters had strong objections to the form this scrutiny should take and the costs involved.

Suppliers have incentives to provide services at a quality that meets consumer demand

4.103 Incentives for quality of service are principally promoted by the quality standards we set. The expenditure forecasts we set should be adequate to meet these standards.[75] However, they should also take into account other regulatory and commercial requirements for quality of service levels.

[74] Orion "Submission on Gas DPP policy paper" (28 September 2016), para 16; GasNet "Submission on Gas DPP policy paper" (28 September 2016), para 6; Powerco "Submission on Gas DPP policy paper" (28 September 2016), para 103.1.

[75] See Chapter 7 for a discussion of quality standards.

Chapter 5 Our forecasts of supplier expenditure

Purpose of this chapter

5.1 This chapter provides our draft forecasts of supplier expenditure, which we determined by implementing the approach outlined in Chapter 4. It also describes our consideration of additional expenditure-related adjustments to the DPPs.

Our draft expenditure forecasts for the proposed regulatory period

5.2 Our draft forecast of total supplier expenditure for the proposed regulatory period is provided in Table 5.1. The expenditure forecasts in Table 5.1 are presented in 2016 present values.

Table 5.1 Our expenditure forecasts (2016 present value, '000s)

Supplier	Opex	Capex	Total
First Gas distribution	$31,044	$30,021	$61,064
First Gas transmission	$173,043	135948	$308,991
GasNet distribution	$7,005	$3,599	$10,604
Powerco distribution	$72,530	$59,574	$132,104
Vector distribution	$49,659	$76,428	$126,087
Industry total	**$333,281**	**$304,873**	**$638,154**

5.3 The remainder of this chapter:

5.3.1 compares our forecasts with historic levels of expenditure;

5.3.2 compares our forecasts with suppliers' own forecasts; and

5.3.3 explains our treatment of ownership changes in the gas pipeline sector.

Comparison against historic levels of expenditure

5.4 Table 5.2 compares our forecast of average annual expenditure over the proposed regulatory period against the historic level of expenditure (in real terms). The historic levels of average annual expenditure are based on the three years of 2012/13 to 2014/15 where possible. They include the same approach to splitting and merging for Vector and First Gas as we used for the forecasting process (described in paragraphs 4.24 to 4.27).

Table 5.2 Our expenditure forecast: change from actual historic expenditure

Supplier	Opex	Capex	Total
First Gas distribution	12.3%	1.7%	6.7%
First Gas transmission	-15.5%	43.0%	2.7%
GasNet	-1.1%	15.6%	4.1%
Powerco	6.9%	28.6%	15.8%
Vector	3.0%	2.6%	2.7%
Industry total	**-5.6%**	**21.7%**	**5.8%**

5.5 In some cases the expenditure is lower than the fall-back level because the supplier forecast the expenditure as being below the fall-back level. Some suppliers also had other categories of expenditure set at the fall-back, so that the overall result was below the fall-back level.

Comparison against suppliers' own forecasts

5.6 As described in Chapter 4, our forecasts are based on suppliers' own forecasts with downward adjustments where high levels of expenditure are unsupported or unsuitable to be considered under a DPP. Table 5.3 shows our expenditure forecasts as a proportion of the suppliers' own forecasts for the draft decision (as a percentage of the total in real terms).[76]

Table 5.3 Forecast expenditure as a percentage of suppliers' own forecasts

Supplier	Opex	Capex	Total
First Gas distribution	100%	61%	76%
First Gas transmission	93%	58%	78%
GasNet	100%	89%	96%
Powerco	100%	100%	100%
Vector	96%	99%	97%
Industry total	**95%**	**76%**	**86%**

[76] We will consider further evidence from suppliers on the unsupported areas provided as part of submissions on our draft decision.

Downward adjustments to suppliers' own forecasts

5.7 As described in Chapter 4, Strata provided us with recommendations on which areas of expenditure to accept and reject, based on the supplier evidence tests that it undertook. We agreed with their recommendation to not accept the following areas of expenditure.[77]

5.7.1 GasNet: asset replacement and renewal (capex);

5.7.2 Vector: systems operations and networks support (opex);

5.7.3 Vector: business support (opex);

5.7.4 Vector: non-network (capex);

5.7.5 First Gas distribution: consumer connection (capex);

5.7.6 First Gas distribution: system growth (capex); and

5.7.7 First Gas transmission: routine and corrective maintenance and inspection (opex).

5.8 In addition, we have not accepted the significant increase in the asset replacement and renewal (capex) category of expenditure for First Gas transmission. In particular, two projects forecast by the First Gas transmission business in that expenditure category are not adequately supported—the Gilbert Stream project and the White Cliffs preparatory work. These projects were considered individually because of their relatively large forecast expenditure and project uncertainties. Our consideration of these two projects is provided below in paragraphs 5.9 to 5.16.

The Gilbert Stream project

5.9 The Gilbert Stream project is forecast to cost approximately $9 million. The project is described in the AMP as:

> A section of the 400 Line at Pukearuhe, approximately 75m north of the Gilbert Stream, is threatened by marine erosion of the cliff face. The cliffs in the immediate area are around 50m high, with the proximity of the Maui 400 Line at its nearest point now approximately 10m from the cliff edge. Regular monitoring, reporting and evidence presented by the Pipeline Integrity Team has resulted in the elevation of the integrity risk to the pipeline. A realignment project has since been initiated to reduce the risk to the pipeline. Independently, a comprehensive Emergency Response Plan is currently being drafted that will provide a plan that would be actioned in a sudden and large failure event. The pipeline realignment pre-work is currently underway, with expected completion in FY18.[78]

[77] Alongside this paper we have published reports provided by Strata, which explain the reasons for its recommendations, and Excel spreadsheets for each supplier, which show the results of the variance, AMP, and supplier evidence tests for each area of expenditure.

[78] First Gas “Gas Transmission Asset Management Plan – 2016” (1 October 2016), page 80.

5.10 For a project of this scale, the AMP does not adequately support:

5.10.1 the timing requirements of the project;

5.10.2 the need for the project; or

5.10.3 the forecast cost of the project.

5.11 First Gas has not had sufficient time to provide supplier evidence for the Gilbert Stream project yet so we have not included the expenditure in our forecast. Any evidence supplied by First Gas will be considered in our final decision.[79]

White Cliffs preparatory works

5.12 The First Gas transmission business forecast approximately $82 million of capex for the White Cliffs project, some of which falls within the proposed regulatory period.

5.13 The White Cliffs project is more suited to the greater level of scrutiny that can be provided under a CPP. Also, CPPs allow for the inclusion of contingent projects, which may be appropriate if the White Cliffs project was broken into multiple stages.

5.14 The full White Cliffs project is described by First Gas in its AMP:

> One of our key focuses in the coming year will be to determine the solution and timing for realignment works at White Cliffs in Taranaki. In this area, our pipelines are located in an area of coastal erosion risk 3km south of the Tongaporutu River... The work at this site will involve the realignment of two high pressure pipelines.
>
> Horizontal directional drilling (HDD) is likely to be selected for the realignment work. The HDD installation is considered to be the most appropriate technique as it would be the most effective solution in terms of practicality and would be the lowest cost approach. It would ensure protection from future erosion and reduce the impact of construction activities on properties, heritage sites and the environment.
>
> The project is expected to cost in the region of $82 million and be completed by FY23. However, the timing of this project may change with further monitoring and we will keep stakeholders informed as more information becomes available.[80]

Fall-back for First Gas transmission's asset replacement and renewal capex

5.15 We have forecast First Gas transmission's asset replacement and renewal capex at the standard fall-back. However, based on the CPP fall-back policy described in paragraphs 4.51 to 4.58 we have also added a CPP fall-back to our forecast of opex. This CPP fall-back is in recognition that the reason for the White Cliffs preparatory

[79] If we had accepted the expenditure in this category, except for the White Cliffs project, First Gas transmission's starting price would be 1% higher. This is assuming our estimate of the White Cliffs project costs being approximately $71m during the proposed regulatory period (of First Gas' total project forecast of $82m, which overlaps into the subsequent regulatory period).

[80] First Gas "Gas Transmission Asset Management Plan – 2016" (1 October 2016) pages 3–4.

project being considered to be unsupported is that it is more appropriate for consideration under a CPP.

5.16 We have estimated the CPP fall-back because the cost of a CPP application is not included in First Gas' forecasts. Our forecast for the draft decision is $0.8m, which we think is appropriate:

5.16.1 on the basis of our experience with the Orion CPP;

5.16.2 because some of the work completed for the first CPP (Orion) will not need to be repeated;

5.16.3 because some of the costs can be recovered through the recoverable cost term;

5.16.4 considering the relatively moderate scale and complexity of a potential First Gas transmission CPP; and

5.16.5 considering the improvements that have been made to the CPP IMs.

Treatment of changes in the gas pipeline sector

5.17 We have considered two particular changes in the gas pipeline sector. Most recently, GasNet has agreed to sell its assets in the Bay of Plenty to First Gas. Also, we have accounted for some economy of scale effects resulting from industry transactions between First Gas, Vector, and MDL.

Treatment of GasNet Bay of Plenty asset sale

5.18 First Gas is proceeding with the purchase of the gas distribution assets being built by GasNet in the Bay of Plenty.[81] We have accounted for this transaction in our draft decision for GasNet's and First Gas' distribution business DPPs.

Impact on GasNet

5.19 The assets have not yet been commissioned by GasNet, so they were not yet in GasNet's regulatory asset base and have not yet been depreciated for regulatory purposes. They qualify instead as 'works under construction'.

5.20 GasNet did not include any planned expenditure relating to those assets in its expenditure forecast. Therefore, we have not had to account for the asset sale in GasNet's DPP.

Impact on First Gas

5.21 We have included an estimate of the cost of the assets in our forecast of First Gas' capex for 2016/17. This capex forecast is used to forecast the opening value of

[81] The Commission is currently considering whether the transaction raises concerns under section 47 of the Act.

First Gas' regulatory asset base for the start of the proposed DPP on 1 October 2017. As these assets have not yet been commissioned, they will enter First Gas' regulatory asset base at the cost of purchase plus any subsequent capitalised costs required to commission them, including the cost of financing from the date of First Gas' acquisition to the date of commissioning.

5.22 Any difference between the actual costs and the forecast amount we have used will be corrected in the DPP through the capex wash-up mechanism.

5.23 First Gas did not include any planned capex or additional opex relating to these assets in its expenditure forecasts for the proposed DPP. Therefore we have not included any further expenditure in relation to these assets in our forecasts beyond the final year of the current DPP.

Treatment of the First Gas industry transactions – economies of scale

5.24 As described in Chapter 4, we have considered whether there are any identifiable gains or losses from changes in economies of scale resulting from the industry transactions involving First Gas. We have adjusted our expenditure forecasts by these amounts so that the impact will be borne by the supplier for the first full regulatory period following the transaction.

5.25 For the draft decision we have not yet identified any economy of scale effects from the transmission merger or the sale of Bay of Plenty assets from GasNet to First Gas. However, we have identified some economy of scale losses in the Vector distribution business (but not the First Gas distribution business) in both capex and opex. Due to this, we have made the following downward adjustments to Vector's forecast expenditure (in real 2016 prices):

5.25.1 capex: $0.6 million

5.25.2 opex: $1.6 million

5.26 Further detail regarding our consideration and identification of gains and losses from changes in economies of scale is provided in Attachment E.

Chapter 6 Forecasting constant price revenue growth

Purpose of this chapter

6.1 This chapter:

6.1.1 explains the role of CPRG in the setting of a price-quality path for GDBs;

6.1.2 highlights the draft decision on CPRG forecasts; and

6.1.3 sets out our draft decisions on CPRG for the 2017 Gas DPP.

Draft decision outputs

6.2 Table 6.1 below shows the CPRG forecasts.

Table 6.1 CPRG forecasts

	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
Powerco	1.15%	1.14%	1.07%	1.06%	1.05%	1.04%
Vector	1.67%	1.62%	1.52%	1.50%	1.48%	1.45%
First Gas distribution	1.13%	1.11%	1.08%	1.07%	1.06%	1.05%
GasNet	(0.68%)	(0.67%)	(0.63%)	(0.64%)	(0.65%)	(0.65%)

6.3 These forecasts are higher than they were for the previous DPP except for GasNet. As this chapter will outline CPRG forecasts are informed by both historical ID information and a forecast from Concept Consulting. The increased draft CPRG forecasts have been driven predominantly by increased trended historic growth captured through ID and an information request.

Impact of CPRG on starting price

6.4 When the CPRG outputs are combined with other inputs into the financial model a starting price is determined for each distribution business. If CPRG forecasts were increased by 1% for each supplier this would result in a starting price decrease of 1.9% under the conditions set out in this DPP.

How constant price revenue growth forecasts are used

6.5 CPRG forecasts predict the rate at which revenues will change due to changes in quantities delivered and number of connected consumers, with prices remaining constant. The forecast is used to set starting prices as well as revenue growth.[82]

6.6 CPRG forecasts are used along with forecasts of inflation (CPI) to estimate the amount that each supplier's revenue will change throughout the regulatory period. Forecasts for the two years before a regulatory period starts are also used in the ΔD calculation in the price-path compliance formula.[83, 84]

Context of CPRG draft decisions

Form of control decisions and the need for CPRG

6.7 As part of the IM review, we decided to:

6.7.1 maintain a weighted average price cap for GDBs and continue to use lagged quantities;[85] and

6.7.2 maintain a revenue cap for GTBs, but move to a pure revenue cap allowing for wash-up of over- and under-recovery.[86]

6.8 As a result of this change in the IMs, no CPRG forecasts will be required for the gas transmission business of First Gas.

Proposed approach

6.9 After considering the performance of the approach used in 2013 and the views of industry participants and stakeholders, we propose to adopt a similar approach for GDBs to that used in the previous Gas DPP.[87]

6.10 The major change from 2013 is that we propose to further tailor CPRG forecasts to better reflect the operating environments of the individual gas businesses. More

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82 For a discussion on how CPRG forecasts fit into the calculation of starting price or revenue, see the reasons paper for the initial (2013) default price-quality paths: Commerce Commission "Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services" (28 February 2013), paras 2.27–2.36. http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/initial-default-price-quality-path/.

83 Commerce Commission "Compliance requirements for the default price-quality paths for gas pipeline services" (1 March 2013).

84 ΔD is used in assessing compliance for the first year of a regulatory period to allow for lagged quantities. The basic equation is ANRY1 = MAR / ΔD, where ΔD is equivalent to two years CPRG forecast. This is no longer required for Gas Transmission businesses as they are now subject to a revenue cap.

85 Commerce Commission "Input methodologies review decisions: Topic paper 1" (20 December 2016), para 216.

86 Commerce Commission "Input methodologies review decisions: Topic paper 1" (20 December 2016), para 178.

87 Commerce Commission "Reasons for setting default price-quality paths for suppliers of gas pipeline services" (28 February 2013), Attachment E.

specifically, we are proposing to use gas demand forecasts that relate to the region in which each gas business operates.

6.11 Concept Consulting, on behalf of the GIC, has produced a gas demand study, as it also did in 2012. This demand forecast has been produced at a regional level for the first time covering Central, Lower, Auckland, Non-Auckland and Whanganui regions. We propose to use these forecasts instead of one aggregate forecast covering the North Island. We commissioned a separate technical report supporting the Concept Consulting study that outlines, in detail, the forecasting approach undertaken by Concept Consulting.[88]

Why we are changing the 2013 approach

6.12 Our approach seeks to retain forecasting approaches where they remain fit for purpose. In the process and issues paper published on 29 February 2016, we stated that:[89]

> Our current view is that, subject to assessing forecast performance, we will adopt a similar approach to forecasting CPRG for gas distribution and possibly transmission businesses as in the 2013 Gas DPP reset. However, there may be opportunities for potential improvements.
>
> As part of our work reviewing the IMs, we are considering taking a more tailored approach to setting the DPP where this can be done without significantly increasing cost. There may be a case for tailoring suppliers' CPRG forecasts.

6.13 Submitters on the policy paper generally supported using this forecast prepared by Concept Consulting:

> First Gas broadly support the Commission applying a more tailored approach to forecasting CPRG[90]
>
> Powerco believes the 2013 forecasting approach remains fit for purpose and supports the use of regional demand forecasts[91]

Structure of the CPRG model

Three gas user groups modelled for GDB CPRG forecasts

6.14 In line with the previous Gas DPP we have modelled CPRG separately for each of the three gas user groups – residential, industrial, and commercial users. Once again we have relied on load group information received from suppliers. Figure 6.1 highlights this approach.

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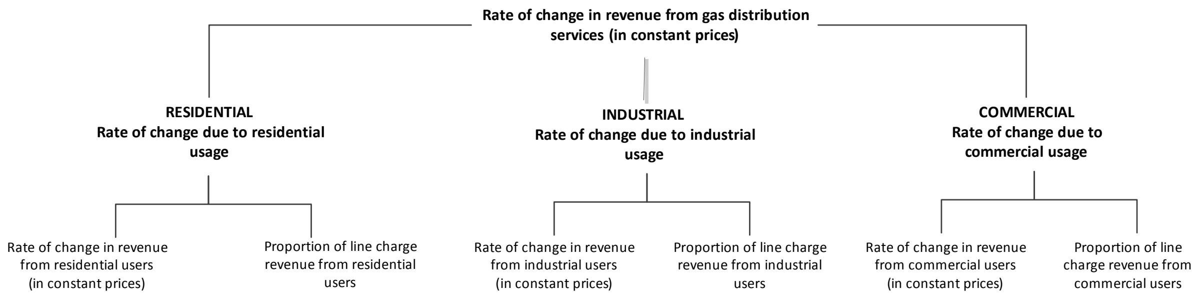
88 Concept Consulting Group LTD "Approach to developing distribution network demand projections" (4 July 2016).

89 Commerce Commission "Gas Pipeline DPP reset – Process and issues paper" (29 February 2016), paras 3.51–3.52.

90 First Gas "Submission on Gas DPP policy paper" (28 September 2016).

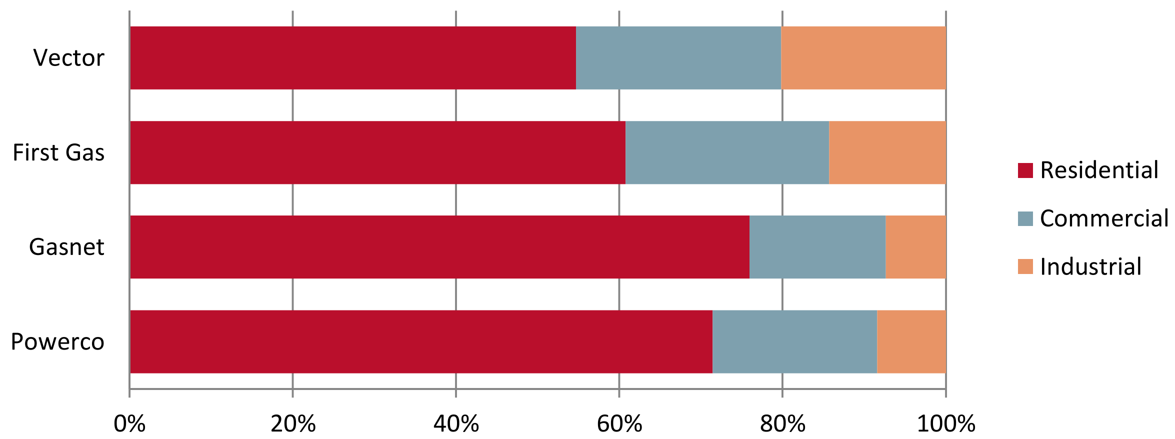
91 Powerco "Submission on Gas DPP policy paper" (28 September 2016).

Figure 6.1 Modelling constant price revenue for gas distributors



6.15 It is important to model CPRG by user type because distribution businesses have quite different user profiles, as can be seen in Figure 6.2.

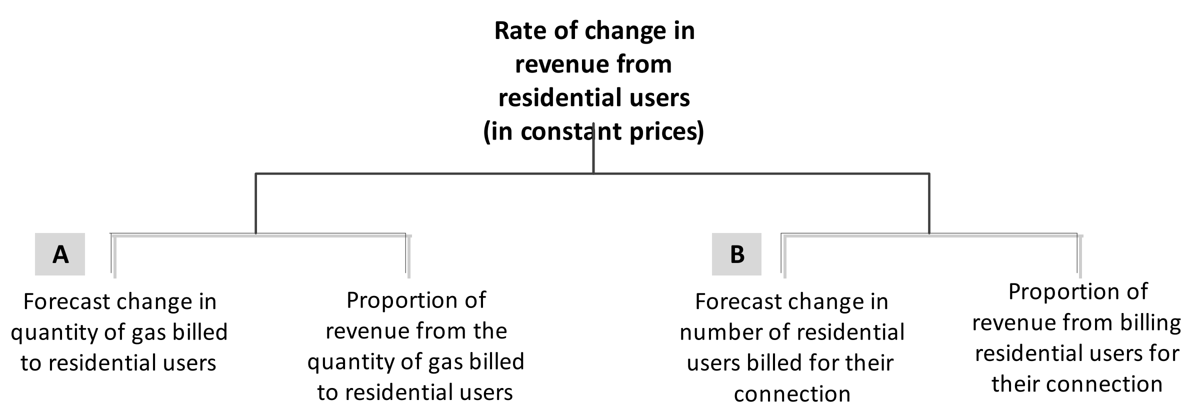
Figure 6.2 User group revenue breakdown by distribution business (2015 disclosure year)



Disaggregation of revenue by charging structure is retained

6.16 Our approach to modelling CPRG will align with the GDBs' charging structure, as shown in Figure 6.3 for residential users. The rates of change for industrial and commercial users were calculated in the same way.

Figure 6.3 Approach to modelling rate of change in revenue from residential users



Disaggregation of billing quantities for different user groups

6.17 Figure 6.4 to Figure 6.6 show the split of revenue from the two charging structures (quantity of gas billed and number of connections) by user group for each of the GDBs.

Figure 6.4 Composition of revenue from residential users (2015 disclosure year)

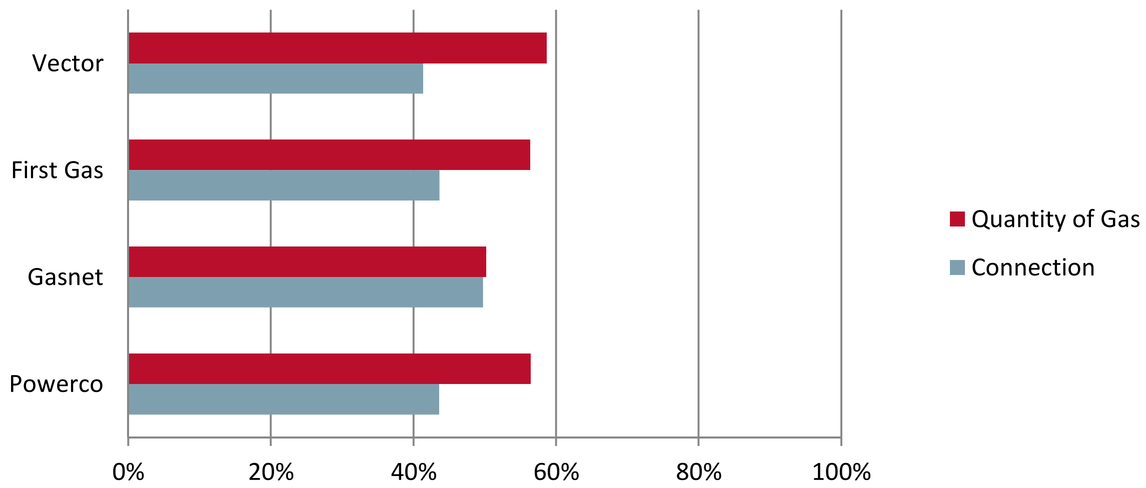


Figure 6.5 Composition of revenue from commercial users (2015 disclosure year)

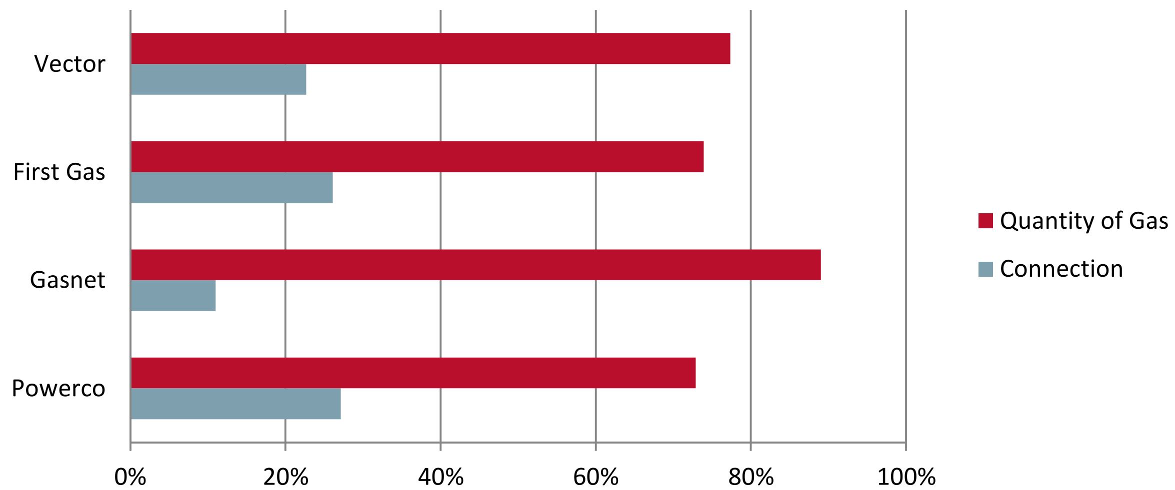
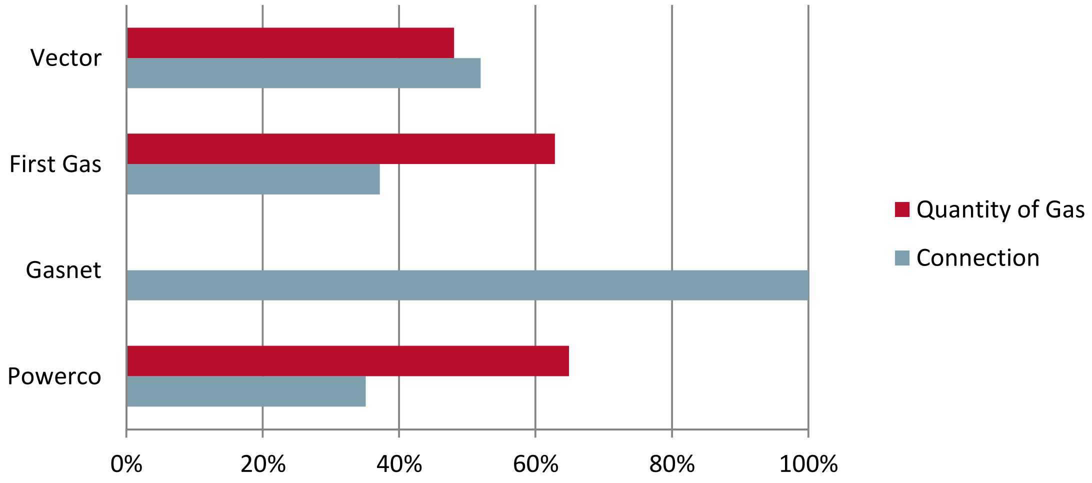


Figure 6.6 Composition of revenue from industrial users (2015 disclosure year)



6.18 As shown in Figures 6.4 to 6.6, this disaggregation by user group is important as suppliers have quite different pricing profiles.

Approach to forecasting change in quantity of gas billed (variable charge)

6.19 Our forecast of the change in the quantity of gas billed ('A' in Figure 6.3) for each user type – residential, industrial and commercial – will be the average of:

6.19.1 each distributor's (three-year) historical trend in billed quantity by price component (variable GJ or kWh); and

6.19.2 the regional, moderate gas supply scenario relating to each distributor from the demand forecasts by Concept Consulting Limited.

6.20 These tailored, regional forecasts are representative of the following areas:

6.20.1 Central

6.20.2 Lower

6.20.3 Auckland

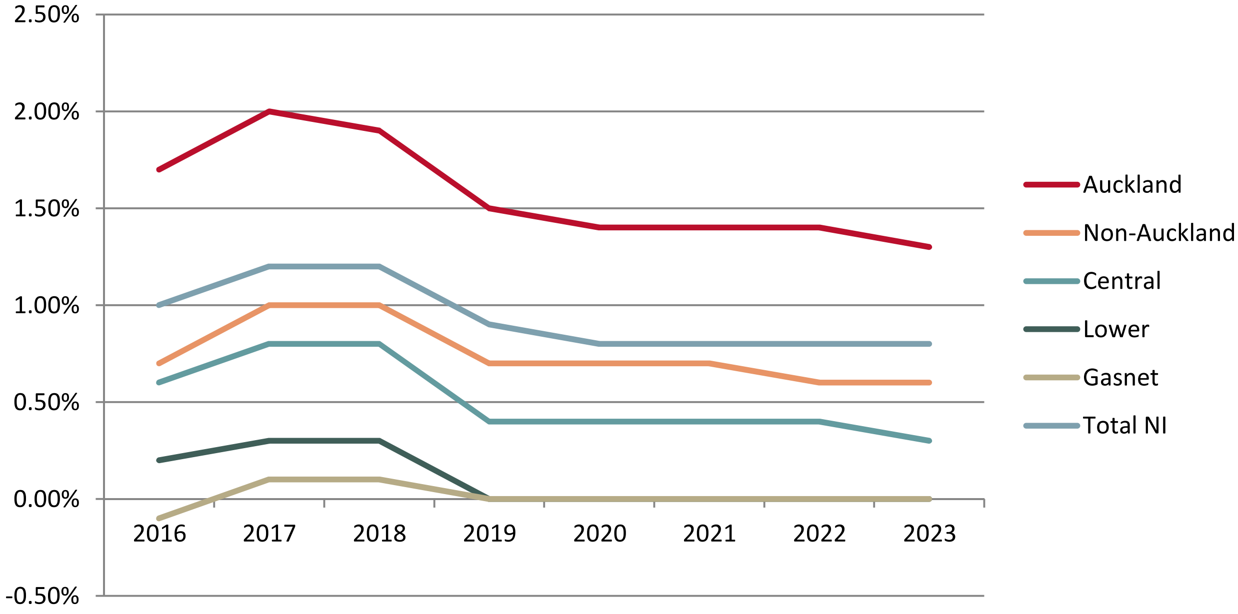
6.20.4 Non-Auckland

6.20.5 Whanganui

6.21 The projections contained in the updated Concept Consulting demand study are also at a user group level: residential, commercial, and industrial demand. These align with our CPRG model and eliminate the need to make assumptions on demand by user group, as was necessary in 2013.[92] Figure 6.7 shows the forecast gas demand growth rates by region and at a total North Island level.

6.22 The higher Concept Consulting forecasts in 2017 and 2018 are driven predominantly by an increase in forecast gross domestic product in these years.

Figure 6.7 Forecast gas demand growth rates by region and total North Island – mid-scenario report by Concept Consulting



6.23 We propose to map each GDB to the regions in the Concept Consulting demand study as follows:

6.23.1 Powerco – Central and Lower

6.23.2 Vector – Auckland

6.23.3 First Gas – Non-Auckland

6.23.4 GasNet – Whanganui

6.24 If we aggregate the Concept Consulting report to a total North Island level, as shown in Figure 6.8, the overall growth is very similar to that obtained from the gas demand report prepared by the GIC and used for the previous Gas DPP.[93]

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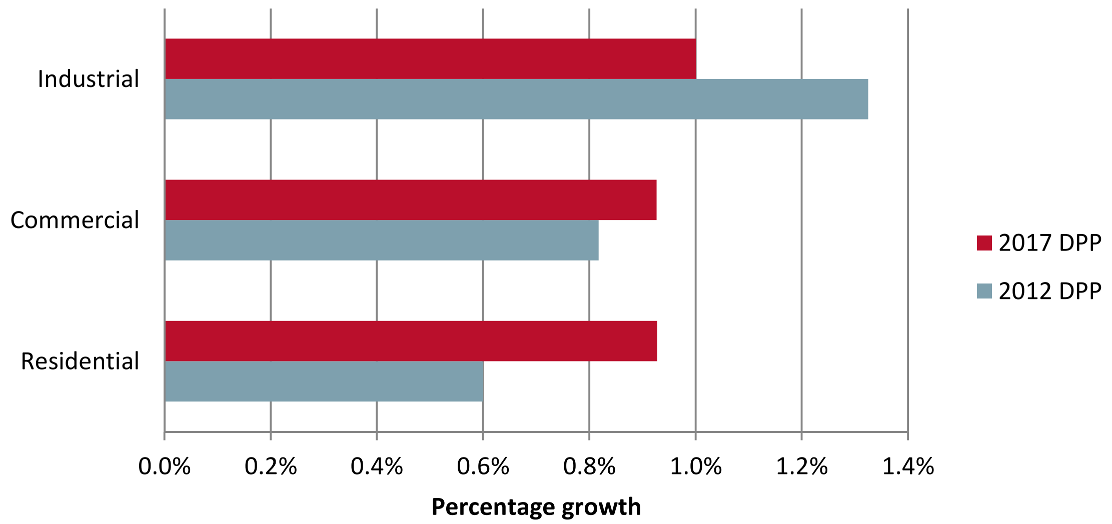
[92] In 2013 we had to make assumptions in order to apply Concept Consulting's moderate scenario – see Commerce Commission, "Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services" (28 February 2013), para E30.

[93] 'Gas Supply and Demand Scenarios - December 2012': http://gasindustry.co.nz/work-programmes/gas-supply-and-demand/background/

Figure 6.8 Aggregate North Island moderate growth scenarios taken from Concept Consulting forecasts used in 2012 and 2017 Gas DPP resets



Approach to forecasting change in quantity of installation control points (fixed charge)

6.25 To forecast the change in revenue from per connection charges ('B' in Figure 6.3) we take the trend in the number of historical installation control point (**ICP**) connections. For each distributor and for each type of user (residential, industrial and commercial), we calculate the trend growth in the number of connections between 2013 and 2015.

Growth in suppliers' fixed and variable quantities from Information Disclosure

6.26 Figure 6.9 - Figure 6.12 illustrate the varying trended pattern found in the suppliers' own ID. Variable growth is measured in billed quantities by GJ or kWh, fixed growth is measured in the number of ICPs at the end of the disclosure year. The charts capture logged growth across three years. Where billed kWh increases while the number of ICP's decreases, it indicates that consumption per ICP is increasing.

Figure 6.9 Powerco Information Disclosure data – trend in 2013 – 2015 logged values

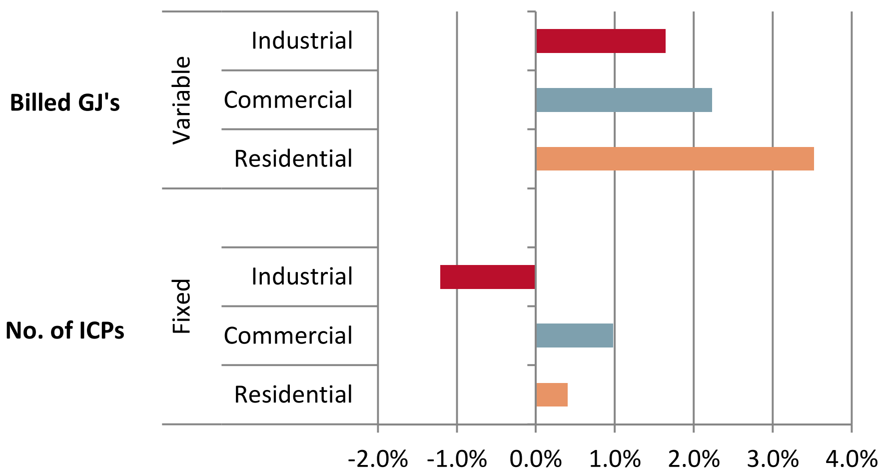


Figure 6.10 GasNet Information Disclosure data – trend in 2013 – 2015 logged values

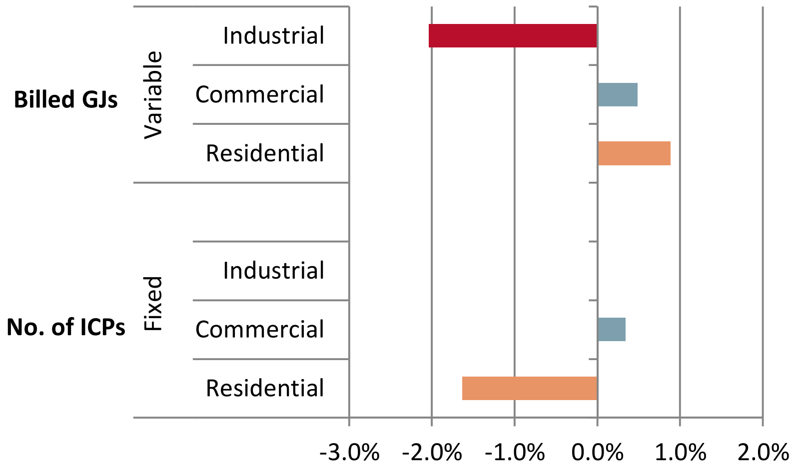


Figure 6.11 Vector Information Disclosure data – trend in 2013 – 2015 logged values

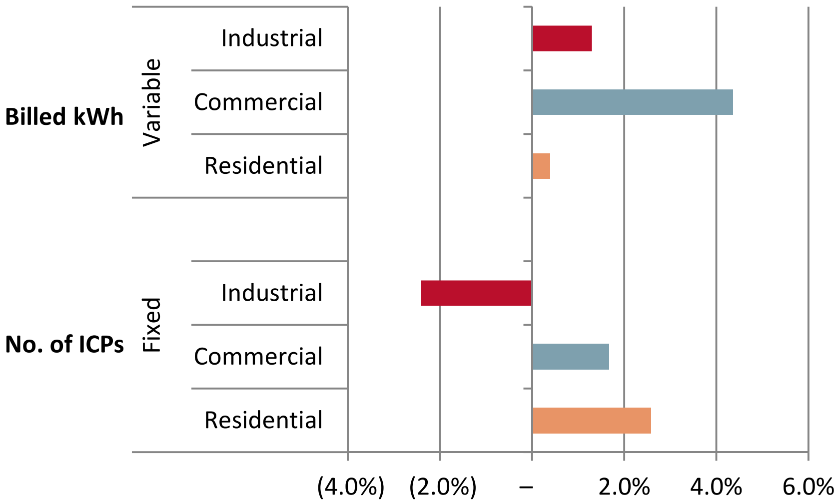
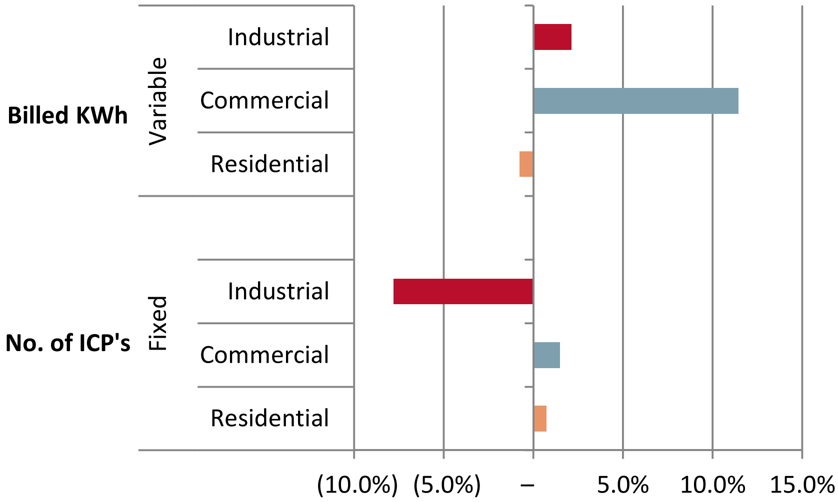


Figure 6.12 First Gas Information Disclosure data – trend in 2013 – 2015 logged values



6.27 The large variances observed in the three-year trend between user groups, as well as pricing structures for each supplier, demonstrate why we forecast CPRG at the billed GJs or kWh, and numbers of ICPs at each user group level.

Incorporating asset management plan forecasts into CPRG forecasts

6.28 We acknowledge MGUG's submission on the policy paper that suppliers' own AMP forecasts be used in the CPRG forecasting process. We believe this proposal, which would link expenditure forecasting with CPRG forecasting, has merit.[94]

6.29 However, we believe the demand forecasting components of the AMP schedules lack transparency and that our current fundamental approach remains fit for purpose.

6.30 As a cross-check, we have looked at the forecast demand captured in each supplier's AMP. Applying the same revenue percentages in terms of fixed versus variable split as per the CPRG model, we see two suppliers with higher forecasts from the CPRG model when compared with their AMPs, and two below. GasNet aside, the businesses' AMP forecast demand growth is within 0.3% of their CPRG forecast growth.

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[94] MGUG "Submission on Gas DPP policy paper" (28 September 2016).

Chapter 7 Setting standards for quality of service

Purpose of this chapter

7.1 This chapter:

7.1.1 sets out our draft decisions on setting quality standards; and

7.1.2 outlines what we have considered in coming to these decisions.

Summary of our proposed quality standards

7.2 Having considered submissions on our policy paper, our view remains that reliability is the most important aspect of quality of service. Specifically, avoiding interruptions to supply.

7.3 We have focused on whether existing regulatory and commercial arrangements provide sufficient incentives for suppliers to deliver services at a level that reflects consumer demands.

7.4 Our draft decisions on quality standards are to:

7.4.1 retain the response time to emergencies (**RTE**) quality standard for all suppliers;

7.4.2 introduce a new quality standard based on major interruptions for GTBs only; and

7.4.3 introduce drafting improvements relating to the RTE quality standard and the definition of emergency.

7.5 In reaching our draft decisions on quality standards, we have used a decision-making framework that incorporates:

7.5.1 identifying the aspects of quality of service that are the most important to consumers, and the level of performance they expect;

7.5.2 assessing whether and how the current regulatory and commercial framework incentivises businesses to deliver this performance;

7.5.3 considering what aspects of the Commission's 'regulatory tool-kit' are most appropriate to remedy any gaps; and

7.5.4 considering whether the advantages to consumers of any new quality standards outweigh the cost of compliance to businesses.

Response time to emergencies standard

7.6 Our draft decision is to retain the RTE quality standards for all gas suppliers.[95] In our view, the incentives we identified in our 2013 final decision remain relevant:[96]

> [The RTE standards] provides the supplier with an incentive to promptly respond to emergencies, and provides a proxy for the responsiveness to the safety needs of consumers. Together with the safety regulations already placed on gas suppliers, the targets will therefore help to ensure that services are provided at a quality that consumers demand.

7.7 Submissions on our policy paper support retaining the RTE quality standards. Suppliers, in general, have highlighted that they have the necessary systems and processes in place to report against the existing standards. However, Powerco suggested extending the period for requesting that GPBs be permitted to treat RTEs where suppliers exceed 180 minutes to respond to an emergency as being compliant with the RTE quality standard, from 30 working days to 45 working days.[97]

7.8 We have considered Powerco's suggestion to extend the application period for the 180 minute RTE standard. We have decided to extend the period suppliers have to provide information about the causes of a failure to meet the 180 minute RTE from 30 working days to 45 working days.

7.9 We will approve a supplier’s request to treat the emergency as having complied with the quality standard where they have a reasonable excuse for the failure. If suppliers obtain our approval, they will be able to report that they are compliant with that quality standard in relation to that emergency in their compliance statements.

7.10 The draft determinations also contain drafting changes that simplify the quality standards by replacing the quality standard formulae with words that have equivalent effect to the formulae. We consider that the revised wording improves the clarity of the provisions.

Our consideration of a new quality standard based on major interruptions for suppliers

7.11 Consumer groups identified reliability as the most important aspect of quality. In particular, MGUG said its key concerns are avoiding interruptions to supply and promptly restoring service after any interruption.

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95 These quality standards consist of separate quality standards for RTEs greater than 60 minutes and those greater than 180 minutes. The quality standards for RTEs greater than 60 minutes only apply to GDBs while the quality standards for RTEs greater than 180 minutes apply to both GDBs and GTBs.

96 Commerce Commission "Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services" (28 February 2013), para 4.6.

97 Powerco "Submission on Gas DPP policy paper" (28 September 2016), para 115.

7.12 We have, therefore, considered whether the existing regulatory and commercial arrangements provide effective incentives for suppliers to deliver services at a level that reflects consumer demands.

7.13 In our policy paper, we identified a potential gap in the current regulatory settings. While most aspects of consumer demand are covered in the wider suite of regulation, we were concerned that there was not adequate accountability for suppliers following major interruptions.[98]

7.14 As a result, we proposed introducing a new quality standard based on major interruptions for all gas suppliers and sought submissions on our emerging view.

We are introducing a new quality standard based on major interruptions for GTBs

7.15 Our draft decision is to introduce a new quality standard for GTBs. The standard will focus on major interruptions and incorporate a reporting obligation following a major event.

7.16 Submissions from GTBs and major users have supported a quality standard relating to major interruptions for GTBs.[99]

7.17 While interruptions in gas transmission are rare, they can have a large impact when they do occur. In our view, introducing an interruptions standard is an appropriate measure to incentivise GTBs to maintain reliable gas transmission.

7.18 We discuss implementing the new quality standard for GTBs in paragraphs 7.26 to 7.56.

We are not introducing a quality standard based on major interruptions for GDBs

7.19 Our draft decision is to not introduce a new quality standard based on major interruptions for GDBs.

7.20 GDBs did not support our proposed introduction of an interruption quality standard. In particular, they highlighted that it was unclear whether there was an issue that warranted introducing an interruptions standard.

7.20.1 Powerco agreed that, following a major event, it is appropriate for suppliers to provide stakeholders with information about the cause of an interruption, its impact, and the likelihood of it recurring.[100] However, in Powerco's view there was no evidence that customers were dissatisfied with current service levels.

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98 Commerce Commission "Policy paper for setting price paths and quality standards" (30 August 2016), para 5.17.

99 First Gas "Submission on Gas DPP policy paper" (28 September 2016), page 5; Methanex "Submission on Gas DPP policy paper" (28 September 2016), para 14; MGUG "Submission on Gas DPP policy paper" (28 September 2016), para 31.

100 Powerco "Submission on Gas DPP policy paper" (28 September 2016), para 122.

7.20.2 Similarly, Vector submitted that we should not proceed until we have clear evidence that customers are concerned with the current levels of risk management.[101]

7.20.3 GasNet submitted that it was not clear that a new regulatory target would improve the quality of service that it provides or that is demanded by its customers.[102]

7.21 MGUG supported introducing an interruptions quality standard. MGUG stated that while consumers and suppliers were generally aligned on achieving reliability, the cost of failure can be higher for consumers. This would create different expectations of what is efficient expenditure to ensure reliability.[103]

7.22 While introducing a quality standard based on major interruptions is unlikely to impose significant compliance costs on GDBs, we have considered whether gas distribution reliability could be improved by adding further incentives.

7.23 Historic data across the 19 years of data we have available shows few significant interruptions.[104] In their Gas Information Disclosure Regulation (**GIDR**) disclosures:

7.23.1 GasNet only noted one significant outage (in 2010);

7.23.2 Powerco only noted two (in 2007 and 2009); and

7.23.3 Vector did not identify any.

7.24 Interruptions on GDB networks are likely to be more localised than a GTB network, and so have a smaller impact on consumers.

7.25 At this time, we consider that it is not necessary to introduce a major interruptions quality standard for GDBs. Given there have been few significant interruptions and the likely smaller impact of interruptions, our view is that the introduction of a major interruptions quality standard is unlikely to deliver additional benefits, and may lead to unnecessary costs being passed on to consumers.

Implementing the major interruptions quality standard for GTBs

7.26 We have decided to introduce a new major interruptions quality standard for GTBs. The standard will focus on major interruptions, and incorporate a reporting obligation. This section sets out how we propose to implement the new interruptions standard, including:

7.26.1 specifying the quality standard that GTBs must meet;

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[101] Vector "Submission on Gas DPP policy paper" (28 September 2016), para 92.
[102] GasNet "Submission on Gas DPP policy paper" (28 September 2016), para 56.
[103] MGUG "Submission on Gas DPP policy paper" (28 September 2016), para 34.
[104] We have reviewed ID disclosures (2013-2015), and business' Gas Information Disclosure Regulations (GIDR) (1997-2012). Not all disclosures were publically available for all businesses.

7.26.2 the purpose and contents of the report that GTBs must provide to stakeholders following a major interruption; and

7.26.3 our potential enforcement response following a breach of the major interruptions quality standard.

Specifying the major interruptions quality standard

7.27 The new quality standard for GTBs will capture any significant interruption in the supply of services on the transmission network. More specifically, the quality standard will be linked to critical contingencies that result in curtailments.

7.28 Submissions have supported a zero interruptions standard. For example, First Gas (as First State Investments) stated that its internal target for interruptions is already zero.[105]

7.29 In our policy paper, we sought views on how to define an interruption. We suggested either using the definition under ID, or linking the definition to Critical Contingency Management (**CCM**) events.[106]

7.30 First Gas expressed support for aligning the definition of an interruption with the definition used for ID.[107] First Gas did not consider there to be any need to link the definition to critical contingencies. In its view, a critical contingency leading to a cessation of supply would be captured under the existing definition.[108]

7.31 Methanex, however, considered the ID definition too limiting as a quality standard. Methanex preferred a focus on critical contingencies, as defined in the CCM regulations. In its view, this approach would cover clearly defined events that generally have a significant impact on consumers.[109]

7.32 Having considered submissions, our draft decision is to link the definition for an interruption to critical contingencies as follows:[110]

> Major Interruption means any declaration of a **Critical Contingency** caused or contributed to by an incident on the transmission system, which results in curtailment directions being issued in respect of any band beyond Band 1.

7.33 Our reasons for this are:

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[105] First State Investments "Submission on the gas DPP process and issues paper" (30 March 2016), page 3.

[106] Commerce Commission "Policy paper for setting price paths and quality standards" (30 August 2016), para 5.39.

[107] The ID definition of an interruption is "Interruption means the cessation of supply of gas for a period of 1 minute or longer, other than by reason of disconnection in accordance with the terms of the contract under which the gas is supplied".

[108] First Gas "Submission on Gas DPP policy paper" (28 September 2016), page 6.

[109] Methanex "Submission on Gas DPP policy paper" (28 September 2016), para 16.

[110] **Critical Contingency** has the same meaning as in Regulation 5 of the Gas Governance Critical Contingency Management Regulations 2008.

7.33.1 our intention is to avoid including negligible events, which would be captured by the 1-minute limit in the ID definition;

7.33.2 events for which a critical contingency is declared are sufficiently serious to warrant the GTB to provide information, and the Commission to potentially investigate; and

7.33.3 the CCM regulations are well established and familiar to the industry.

7.34 We are proposing that events caused entirely by disruption upstream of the transmission are excluded from the definition, as these are outside the GTB's control.

7.35 We also propose that events occurring on the network, which are caused by third parties, are included. While First Gas correctly points out that in most cases these will be outside its control, it is possible that insufficient preparation or mitigation steps could have contributed to the outage or its effects. As such, it is appropriate for the GTB to report on these.

7.36 As discussed below in paragraph 7.52.3, the extent to which the GTB has mitigated the risk of the outage will be a factor we consider when determining the appropriate response to a major interruption.

Reporting obligation for GTBs following an interruption

7.37 Linked to the major interruptions quality standard, we propose including a reporting obligation in line with section 53M(2)(d) of the Act. The reporting obligation will be triggered in any instance where the GTB exceeds the major interruptions quality standard. The report will be made available to the Commission and consumers.

7.38 The principal purpose of the report is to provide GTBs with an additional incentive to avoid major interruptions. However, the report will also:

7.38.1 provide consumers and other stakeholders (including us) with clear, timely information about the cause of the interruption, its impact, and whether similar events may occur in future; and

7.38.2 provide us with information that can be used when considering any enforcement response.

7.39 To meet this purpose, GTBs' reports must contain, at a minimum:

7.39.1 a description of the interruption (including the cause(s), location, and assets involved);

7.39.2 whether the risk of the interruption had been identified in advance, and any steps the supplier had taken to reduce or mitigate that risk;

7.39.3 the duration of the interruption;

7.39.4 the supplier's best estimate of the quantities of services not delivered as a result, and the revenues that it would have earned for any undelivered services, to the extent that it is possible to determine them;

7.39.5 the direct cost of the interruption (including repair costs) to the supplier; and

7.39.6 what actions (if any) the supplier intends to take to avoid similar interruptions in future.

7.40 The GTB report is likely to include matters covered in the post-incident reports that the Critical Contingency operator prepares following the critical contingency incidents. To the extent that the material is duplicated, the GTB can reference the Critical Contingency Management Report (**CCMR**) report.

7.41 However, the two reports differ in the following ways:

7.41.1 the CCMR report is prepared by the CCO, not the GTB;

7.41.2 the focus of the CCMR report is limited to the cause of the critical contingency, and the performance of the CCMR system; and

7.41.3 the CCMR report is not designed to be the basis of any future enforcement response.

7.42 In our policy paper, we proposed that the report should also contain:

7.42.1 the number of customers affected by the interruption;[111] and

7.42.2 the supplier's best estimate of the cost of the interruption to consumers.[112]

7.43 First Gas submitted that the report should be limited to information that is available to it. First Gas noted that it:

7.43.1 did not expect to be able to reliably estimate the number of customers affected by an interruption, as it does not have any direct information on downstream customers; and

7.43.2 should not have an obligation to estimate the cost of an interruption to consumers, as it does not hold information that would enable such estimates.

7.44 We appreciate that GTBs do not hold this information and that requiring them to estimate it may impose additional costs with uncertain benefits. We also agree with

[111] Commerce Commission "Policy paper for setting price paths and quality standards" (30 August 2016), para 5.59.3.

[112] Ibid, para 5.59.6.

First Gas that GTBs may not be best placed to estimate this information. We do not, therefore, consider it necessary to require this information from GTBs.

Timing of the report

7.45 In our emerging view in the policy paper we indicated that the GTB should have to submit its report within six months of the major interruption. First Gas agreed with our emerging view, submitting that our proposed requirement to produce a report within six months was reasonable. First Gas also suggested allowing for a possible extension to the timing requirement if unusual circumstances arose.[113]

7.46 Having considered the matter further, our view is that it would be preferable to reduce the six month period we initially indicated and to include an option for GTBs to seek an extension of time. Seeking an extension would be appropriate where GTBs are unable to provide all the required information within the prescribed period.

7.47 Our draft decision is that the GTB should notify us of any major interruption within five working days after it occurs, and for the GTB to submit its report within 50 working days of the interruption. This will allow the GTB to provide the information relating to the major interruption that is required to be reported on in its annual compliance statements, even where the major interruption occurs at the end of an assessment period.

7.48 An extension of time will be available for submitting some or all of the information required in the report. When applying for an extension, the GTB must demonstrate that there are good reasons for it not being able to provide that information within 50 working days.

Enforcing the major interruptions quality standard

7.49 As with all matters of enforcement, we must be able to respond appropriately to the specific circumstances of the particular breach. For this reason, we cannot determine now how we would treat any breach of the quality standards.

7.50 Submitters have stated that an interruption should not automatically be considered a breach of the quality standard, and that we should provide guidance for when an interruption would be considered a breach.

7.50.1 First Gas considered that this would create higher levels of risk and uncertainty than it already bears, given the discretion the Commission has under section 87, and the lack of guidelines for that.[114]

7.50.2 Methanex was not convinced that an interruption that exceeded the limit being deemed a breach was the correct approach. Methanex suggested

[113] First Gas "Submission on Gas FPP policy paper" (28 September 2016), page 5.
[114] Ibid, page 6.

that the outcome of the report should determine whether a breach has occurred, and if further action is required.[115]

7.50.3 MGUG suggested we adopt the legal concept of Reasonable and Prudent Operator (**RPO**) obligation as the test when considering whether we take action under section 87.[116] MGUG stated that the RPO test does not impose unreasonable expectations on a supplier to provide a level of reliability greater than others would be expected to provide in similar circumstances.

7.51 Our draft decision is that while every interruption that meets the definition set out above in paragraph 7.32 will be a breach of the quality standard, not every breach will trigger the same enforcement response.

7.52 The factors that we may take into account when considering our enforcement response include, but are not limited to:

7.52.1 the magnitude of the interruption;

7.52.2 whether the interruption was due to the GTB's own systems, or a third party event;

7.52.3 whether the risk was identified, and appropriately mitigated, in the AMP;

7.52.4 whether there was anything the GTB reasonably could have and should have done to prevent the interruption or reduce its impact;

7.52.5 whether the GTB acted prudently in preparing for and responding to the interruption;

7.52.6 the cost to the GTB of the interruption;

7.52.7 any other remedies that consumers may have, or sanctions the GTB might face, whether under the terms of transmission service agreements or other regulations; and

7.52.8 whether the GTB has previously breached the quality standards.

7.53 We consider that the fault is a key consideration in deciding on any enforcement response to a failure to comply with the major interruptions quality standard. Accordingly, in reaching our draft decision we also considered two other approaches:

7.53.1 adding a reasonableness criteria to the major interruptions quality standard based on good industry practice standard (GIP); or

[115] Methanex "Submission on Gas DPP policy paper" (28 September 2016), para 18.
[116] MGUG "Submission on Gas DPP policy paper" (28 September 2016), para 43.

7.53.2 excluding major interruptions that are beyond the reasonable control of the GTB.

7.54 Under the first approach, a major interruption would not be a breach of the quality standard where the GTB establishes that it has acted consistently with GIP in relation to the major interruption. We consider GIP to mean that the GTB has exercised the degree of skill, diligence, prudence, and foresight that would reasonably and ordinarily be expected from a skilled and experienced operator engaged in the same type of undertaking, under the same or similar circumstances.

7.55 Under the second approach, the definition of a major interruption would exclude events that are demonstrably outside the GTBs control, for example, natural disasters such as earthquakes, tsunamis or volcanic eruptions.

7.56 We are interested in your views on the alternative approaches to enforcement of the major interruptions quality standard.

Other drafting changes

7.57 We have also introduced some drafting changes to improve the quality standard clauses in the draft determinations that are unrelated to other changes to the quality standards.

7.58 The draft determinations simplify the RTE quality standard clauses by replacing the quality standard formulae with words that have equivalent effect to the formulae. We consider that the revised wording reduces the complexity of the provisions and makes them clearer.

7.59 The draft GTB determination also includes revisions to the definition of an emergency, by replacing the reference to the 'Guidelines for a Certificate of Fitness for High-Pressure Gas and Liquids Transmission Pipelines' with the text contained in the current guidelines. This means that the test for an emergency set before the start of the regulatory period will continue to apply for the full regulatory period even if the guidelines change during the regulatory period.

7.60 We have also amended the second limb of the test for an emergency by replacing the current subjective test "for which the GTB considers a representative of the GTB is required to immediately respond to" with an objective test "that should be responded to immediately based on GIP".

Chapter 8 Assessing compliance with the price-quality path

Purpose of this chapter

8.1 This chapter sets out and explains our draft decisions relating to changes in how suppliers demonstrate (and how we assess) compliance with the price-quality path. The first section summarises our overall approach to compliance with the price-quality path. The second section sets out our draft decisions on aspects of the compliance provisions, specifically:

8.1.1 the rules governing restructures of prices;

8.1.2 what suppliers must do when they engage in certain kinds of transactions where there is a change in ownership or control in relation to their assets or business; and

8.1.3 how the section 52P price-quality path and section 53N compliance requirements are expressed in the DPP determinations.

8.2 This chapter is supported by Attachment F, which discusses the new revenue wash-up mechanism for GTBs. Quality-related compliance matters are discussed separately in Chapter 7.

How suppliers demonstrate compliance with their price-quality paths

8.3 GDBs and GTBs demonstrate compliance with their price-quality paths in different ways and are subject to different forms of control:

8.3.1 GDBs must comply with a weighted average price cap, and demonstrate compliance in 'notional' revenue terms; and

8.3.2 GTBs must comply with a pure revenue cap, and demonstrate compliance in forecast revenue terms.[117]

[117] For a summary discussion on the differences between a price cap and a revenue cap, see Chapter 3. For a detailed discussion of why we have applied these forms of control, see: Commerce Commission "Input methodologies review decisions: Topic paper 1 – Form of control and RAB indexation for EDBs, GPBs and Transpower" (20 December 2016).

GDBs demonstrate compliance with the weighted average price cap using notional revenue

8.4 To demonstrate whether it is complying with its price-path in a given year, a GDB must compare:

8.4.1 the amount of 'notional' revenue that the GDB has generated through its pricing in that year; with

8.4.2 the maximum amount of notional revenue that the GDB is allowed to generate in that year.

8.5 In both cases, the price of the service is multiplied by a corresponding quantity term.

8.6 Rather than using its actual revenue, a GDB must demonstrate compliance on the basis of 'notional' revenue. The revenue is 'notional' because it is based on quantities that are lagged by two years, rather than the quantities for the pricing year. This ensures that the GDB can calculate all necessary values when it sets its prices at the start of the assessment period.

8.7 GDBs calculate two types of notional revenue figures:

8.7.1 'allowable notional revenue' (**ANR**), which is the amount that the GDB's prices are allowed to generate on a notional basis; and

8.7.2 'notional revenue' (**NR**), which is the amount that the GDB's prices generated on a notional basis.

8.8 The difference between NR and ANR reflects the GDB's pricing decisions. This is because equivalent quantity terms are used in both expressions. If the GDB has been setting compliant prices, then NR will be less than or equal to ANR.

GTBs demonstrate compliance with the revenue cap using forecast revenue

8.9 GTBs are now subject to a 'pure' revenue cap, rather than a 'lagged' revenue cap. This means they are required to demonstrate compliance using forecast revenues and forecast allowable revenues.

8.10 Generally speaking, GTBs will comply with their revenue cap so long as they set prices that – based on reasonable forecast quantities – do not exceed their allowable revenue. In the GTB determination, this is expressed as a requirement that forecast revenue from prices (**FRP**) is less than or equal to 'forecast allowable revenue' (**FAR**).[118]

[118] As opposed to allowable *notional* revenue and *notional* revenue, as is the case during the current regulatory period before the IMs were amended.

8.11 The GTB will be required to set prices such that its estimate of revenue will be no more than the allowable revenue. The GTB's estimate of revenue will equal the total of each of its prices multiplied by its year-ahead forecast quantity for that price.

8.12 In addition to the above requirement, the average price increase between assessment periods may not exceed 10%.

GTBs must demonstrate compliance with the revenue cap after setting prices

8.13 GTBs must demonstrate compliance with the revenue cap after they have set prices based on forecast revenue, but before the prices take effect.[119]

8.14 In our June 2016 Gas DPP implementation paper,[120] we proposed that GTBs would have to demonstrate compliance with the revenue cap at two stages:

8.14.1 suppliers would provide a compliance report for each assessment period after prices have been set but prior to the prices taking effect. This approach differs from the current general requirement to provide a compliance report after the end of each assessment period;

8.14.2 suppliers would also have to demonstrate compliance in relation to the revenue wash-up calculations following the end of each assessment period.

8.15 Submitters on this proposal were concerned about timing difficulties that could arise in submitting a compliance report after prices were set but before they took effect.[121]

8.16 PwC noted that requiring two separate compliance statements rather than one, and securing audit and certification of both, would increase costs. They also noted that including extra compliance requirements after setting prices would fall at a time where distributors are generally focused on disclosing pricing methodologies and AMPs as well as managing year-end financial and tax responsibilities, and that securing auditor time may be difficult as a result.

8.17 We acknowledge submitters' concerns about the costs of demonstrating compliance. In making our draft decision we have had regard to these concerns and the need to ensure that the price-quality path operates in the way it was intended.

8.18 In order to ensure that the price-quality path operates in the way it was intended we consider it is important to have information to assess compliance prior to prices taking effect, to be able to take any necessary timely action in the event that

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119 This has also been referred to as *ex ante* submission of compliance reports.

120 Commerce Commission "Gas DPP – Implementing matters arising from the IM review draft decisions – 28 June 2016".

121 See for example PwC "Submission to the Commerce Commission on input methodologies review: Draft decisions papers – Made on behalf of 17 Electricity Distribution Businesses" (4 August 2016), para 21.

forecasts are not reasonable, or where prices are set in a way that recovers revenue in excess of allowable revenue.[122]

8.19 We therefore propose that suppliers would provide two compliance statements with only one being subject to audit assurance:

8.19.1 a compliance statement relating to price setting that is only subject to Directors' certification, and which is due before the start of the assessment period for which prices are being set; and

8.19.2 a compliance statement relating to the revenue wash-up calculation that feeds into price setting for a subsequent year, (and the quality standards) that is subject to Directors' certification and audit assurance, and which is due 50 working days after the end of each assessment period.

8.20 The requirement for certifications should result in lower compliance costs as an external audit of the information would not be required prior to prices taking effect. The certification should not result in significant compliance costs as we would expect a supplier's board and management to 'sign-off' on pricing in any event prior to the setting of prices.

Restructures of prices

8.21 We propose updating the price restructuring provisions of the GDB DPP determinations to provide greater clarity to GDBs that engage in restructures of prices during the regulatory period.

8.22 As GTBs are now subject to a form of control that does not use lagged quantities (ie, a pure revenue cap), there is no need for price restructuring provisions. The equivalent provisions for GTBs relate to the introduction or removal of 'revenue classes' used in assessing compliance with the limit on the average increase in prices, and are discussed in Attachment F.

Restructuring of prices by GDBs

8.23 Where a GDB restructures its prices during a regulatory period, because of the use of lagged quantities described in paragraph 8.6, demonstration of compliance becomes more complex. This is because it can be difficult in certain circumstances to associate current, restructured prices with historic quantities.

8.24 Our draft decision is to adopt elements of the approach taken in the 2015 EDB DPP determination, issued on 28 November 2014.

[122] Section 87C of the Act empowers us to seek an injunction where regulated goods or services are being supplied, or are likely to be supplied in contravention of a price-quality requirement.

8.25 The principle that underpins our approach is that a GDB's customers must, on average, be no worse off had the GDB not restructured its prices. Our draft changes to the GDB determination are found in Clauses 8.5 to 8.8 of the determination.

8.26 In particular, our draft decision:

8.26.1 introduces a definition of ‘restructure of prices’ in the GDB DPP;

8.26.2 contains rules for how GDBs are to determine quantities where they undertake a restructure of prices; and

8.26.3 provides guidance for situations where:

8.26.3.1 lagged quantity data is available;

8.26.3.2 situations where lagged quantity data which corresponds to prices is not available or cannot be practicably related to the restructured price(s); and

8.26.3.3 clarifies the application of the price restructure provisions in the assessment period immediately following a price restructure.

Definition of a restructure of prices

8.27 A restructure of prices is defined as any change to the allocation of connections to consumer groups. This includes the introduction of a new consumer group, and any change in prices, but excludes:

8.27.1 a change in the value of a price applicable to an existing consumer group; and

8.27.2 the movement of connections between existing consumer groups at the request of the customer or retailer.

8.28 This updated definition reduces the ambiguity about when GDBs must apply the price restructuring provisions.

8.29 A restructure of price may impact how a GDB calculates its NR for both the assessment period in which the restructure first applies and the assessment period immediately following the restructure (due to the difficulties in determining lagged quantities).

8.30 A restructure of prices by a GDB during an assessment period does not change the ANR for that assessment period. However, the calculation of the ANR in the assessment period immediately following the restructure may be impacted (due to the difficulties in determining lagged quantities).

8.31 This definition is intended to capture changes in a GDB's internal rules for how tariffs are calculated, which, while they may be described in terms of quantities, still result in prices being restructured.[123]

Application of the restructure of prices rules

8.32 The rules for determining quantities set out in the GDB determination apply:

8.32.1 in the assessment period in which the restructure occurs for the calculation of NR; and

8.32.2 in the assessment period immediately following the period in which the restructure occurs for the calculation of NR and ANR.

Demonstration of compliance where lagged quantity data is or is not available

8.33 The historic information necessary to determine quantities that correspond to restructured prices will be available in some cases. Where two or more customer groups have been combined, the GDB must use the sum of the quantities for the previous groups. Where a customer group has been split, the GDB must allocate the quantities based on the allocation of customers, and the sum of the quantities of the newly created groups must equal the quantities of the original group that was split.

8.34 Where necessary historic quantity information is not available, a GDB must:

8.34.1 determine demonstrably reasonable lagged quantities;

8.34.2 make use of any relevant information related to quantities or otherwise; and

8.34.3 apply a substantially similar methodology for determining quantities in future assessment periods.

8.35 However, when estimating quantities, the GDB must not make use of any forecast quantities.

Submissions on restructures of prices

8.36 Generally submissions on our policy paper were in favour of greater clarity around how to represent compliance following a restructure of prices. GasNet considered that changes should only be made where there was a clear cost or efficiency benefit for suppliers.[124]

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[123] An example of this is if there were changes to a contract which allocated losses to consumers and was reflected in their consumption information, the impact of this is more appropriately represented as a change in price rather than a change in quantity.

[124] GasNet "Submission on the Gas DPP Policy Paper" (28 September 2016), para 59.

8.37 First Gas considered that the approach taken should be as straightforward as possible, noting that more prescription may be helpful, but that it could also lead to a loss of flexibility.[125] Powerco was generally supportive of the proposal to adopt elements of the approach taken in the 2015 EDB DPP.[126]

8.38 We consider that providing greater clarity around the restructure of price provisions for GDBs will lead to greater certainty and therefore less cost for suppliers, and that the improved clarity will outweigh the concerns over loss of flexibility as raised in submissions.

Treatment of transactions between suppliers

8.39 Our draft decision updates the transaction provisions for both GTBs and GDBs, providing greater certainty for suppliers about the treatment of different types of transactions, while retaining flexibility.

8.40 The GDB determination includes detailed provisions for three different kinds of transaction. The GTB determination makes limited provision for notification of transactions by the GTB.

8.41 In addition to these provisions, the GTB and GDB IMs provide for 'major transactions'. Major transactions are those that affect more than 10% of a GDB's RAB.

8.42 These types of transactions, along with how they are treated, are set out in Table 8.1 and are described in the paragraphs below.

[125] First Gas "Submission on the Gas DPP Policy Paper" (28 September 2016), page 7.
[126] Powerco "Submission on the Gas DPP Policy Paper" (28 September 2016), paras 143, 145.

Table 8.1 Types of transactions under the DPP

Transaction type	Definition	Covered in	Treatment for
Amalgamations (GDBs and GTBs)	Two GPBs combine in accordance with Part 13 of the Companies Act	IMs Clause 1.14 Clause 3.2.1	Where both GPBs are on a DPP, the price-paths aggregate from the year following the transaction. Where at least one GPB is on a CPP, the price-paths do not aggregate until the end of that CPP
Mergers (GDBs only)	Two GPBs combine completely by any other method	DPP Clause 10	As for amalgamations
Transfers (GDBs only)	GPB acquires or disposes of assets used in supplying consumers	DPP Clause 10 Schedule 6	Three alternatives: 1) parties agree transfer of ANR 2) parties apply formula in Schedule 6 of the DPP 3) Commission approves alternative methodology
Major transactions (GDBs and GTBs)	Any of the above kinds of transaction where more than 10% of a GPB's RAB is affected	IMs Clause 4.5.4	Commission may reconsider and reopen the price-path

Transactions provisions for GDBs

8.43 In the GDB determination, we are including transaction provisions which cover three types of transactions:

8.43.1 'amalgamations', as defined in the IMs, where two GDBs combine to form a single entity using the process set out in Part 13 of the Companies Act;

8.43.2 'mergers', where two GDBs combine to form a single economic entity by any other means; and

8.43.3 'asset transfers', where a GDB sells (or purchases) some but not all of its assets used to provide gas distribution services to consumers.

Amalgamations

8.44 In the case of an amalgamation of two GDBs who are on a DPP, the IMs require the price-quality paths of the GDBs to be aggregated.[127] The GDB DPP determination sets out how this applies in practice,[128] and includes a requirement for the GDBs to notify the Commission of the amalgamation.[129]

[127] Gas Distribution Services Input Methodologies Amendments Determination 2016 [2016] NZCC 25, clause 3.2.1. Where one or both of the GDBs are on a CPP, the paths do not aggregate until both GDBs return to the DPP.

[128] Gas Distribution Services Default Price-Quality Path Draft Determination 2017, clause 10.

[129] Gas Distribution Services Default Price-Quality Path Draft Determination 2017, clause 10.3.

Mergers

8.45 Where a GDB acquires complete control of another GDB (either through control of its assets or its share capital) the result, in practice, is the same as if the two GDBs had amalgamated.[130] As such, the DPP requires GDBs to treat such a transaction the same as an amalgamation.

Asset transfers

8.46 GDBs may also engage in transactions where they acquire or dispose of assets used to supply consumers with gas distribution services, but where both GDBs continue to operate (as in, the transfer only covers some, but not all of the GDBs regulated assets). In such situations, there is a need for clear rules about how the GDBs involved adjust their price-paths, but also the flexibility to respond to unforeseen circumstances.

8.47 As such, we are proposing an approach to these 'asset transfers' which provides for three options for suppliers to adjust their ANR:

8.47.1 in the first instance, the transacting parties agree between themselves an allocation of ANR and other parameters necessary to demonstrate compliance with the price-path;

8.47.2 in the second instance, where parties cannot agree an allocation, they apply the formulae in Schedule 6 of the DPP determination to derive an allocation of ANR;[131] and

8.47.3 finally, where the parties cannot agree an allocation, and where the provisions in Schedule 6 do not work, the parties may apply to the Commission to use an alternative methodology.

8.48 In any of these cases, suppliers must adjust their NR using the same quantities that result from their adjusted ANR.

8.49 This approach is similar to the one adopted for EDBs at the 2015 EDB DPP reset, with necessary modifications to take into account the differences between the two sectors.

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130 Control in this situation means the acquisition of rights similar to ownership, such as a long-term lease.

131 In these formulae, where assets are purchased from a previously unregulated party, the treatment of pass-through costs differs from transfers between regulated GDBs. The portion of pass-through costs 'recognised' by the transferring party ($K_{proportion,t-1}$) must be those that would have been able to be recognised in that assessment period, applying the definition of pass-through costs in the IMs. Where the transferring party is a GDB, 'recognised' refers to the requirement that pass-through costs were ascertainable when prices were set in the relevant assessment period.

The transactions in the gas sector have highlighted areas for improvement

8.50 There have been gas pipeline divestment and acquisition transactions during the current regulatory period, highlighting uncertainty over how the transactions provisions apply.

8.51 In our policy paper we noted the need to consider:

8.51.1 the continuing appropriateness of the current approach to allocation of ANR or FAR following such a transaction. In particular, we noted the need to consider how pass-through costs, recoverable costs and any historic under-recovery against the price-quality path are included;

8.51.2 whether adjustments are required in the event of an acquisition or divestment transaction if the GTB DPP contains a pure revenue cap;

8.51.3 requiring greater disclosure around the allocation of ANR or AR in situations of a partial network sale or purchase; and

8.51.4 the appropriateness of the transaction provisions in addressing transactions occurring with entities which have specific pipelines that are exempt from regulation under Part 4 of the Act.

8.52 Further, submissions from Powerco and Vector on the policy paper considered that the major transactions provisions have been found to be inadequate. Vector noted that the current major transaction provisions are inadequate for pipeline sales and acquisitions, in particular the splitting of the previous Vector GDB.[132]

8.53 Our general approach in making our draft decisions in respect of major transactions is based on the principle that, in aggregate, during the regulatory period consumers should be no worse off as a result of a major transaction. We also aim to ensure compliance requirements are clear, that no unintended price-quality path breaches occur simply as a result of an acquisition or divestment, and that the costs of compliance are reasonable in the circumstances.

Notification provisions for transactions

8.54 In terms of disclosure requirements for the newly defined 'major transactions', we propose to adopt similar notification provisions as those set out in the 2015 EDB DPP. This includes both a notification requirement for any kind of transaction (amalgamation, merger, or asset transfer), and in the case of asset transfers, additional reporting requirements in the annual compliance statement.

8.55 These notification provisions ensure we would have notice that a transaction has happened (where certain conditions are met), allowing any regulatory issues to be

[132] Vector "Submission on the Gas DPP Policy Paper" (28 September 2016), para 96.

identified. They also provide suppliers with some certainty about any adjustments we may need to make.

Transaction provisions for GTBs

8.56 In the GTB determination, we are removing the detailed rules related to transactions. We are including a requirement for the GTB to notify us where it engages in a 'major transaction' as defined in the IMs.

8.57 The reason for these different approaches to GDBs and GTBs is that there is now only a single GTB, and we consider that the likelihood of any transaction is low, and that in any case such a transaction cannot be easily provided for in advance. As such, the reopener provisions in the IMs are the appropriate way of dealing with transactions involving GTBs.

Treatment of 'major' transactions

8.58 The IMs for both GDBs and GTBs have introduced a new reconsideration provision that allows the Commission to reconsider price-quality paths where the transaction impacts more than 10% of the supplier's RAB.[133]

8.59 As mentioned above, for GTBs, we see this reopener as the best response to any major transaction involving GTBs. For GDBs, we see this reopener as acting as a final 'backstop' where the process set out in the DPP does not work, and the transaction is sufficiently large enough to require a response.

Section 52P and section 53N requirements within a DPP

8.60 As noted in the policy paper, Gas DPP determinations contain section 52P requirements, which include the substantive requirements relating to pricing and quality and other issues like the timing of the regulatory period and the IMs that apply, and section 53N requirements, which require suppliers to provide certain information to us to enable us to monitor compliance with the price-quality requirements.

8.61 We also noted that we have not always clearly differentiated between the section 53N requirements and the section 52P requirements in the previous Gas DPP determinations. This distinction is important to clarify because:

8.61.1 the enforcement options that apply to each type of requirement are different; and

[133] Transactions below the 10% of RAB threshold will be taken into account at the next price-quality path reset. Gas Distribution Services Input Methodologies Amendments Determination 2016 [2016] NZCC 25, clause 4.5.4; Gas Transmission Services Input Methodologies Amendments Determination 2016 [2016] NZCC 26, clause 4.5.4.

8.61.2 section 53N compliance requirements may be changed mid-period, while price-quality path matters cannot be changed during the regulatory period (without using the reconsideration provisions in the IMs).

8.62 In the policy paper, we consulted on whether clarity would be improved by splitting out the section 53N requirements from the main body of the Gas DPP determinations and including them in a separate attachment.[134] We received no submissions or cross submissions disagreeing with our proposed approach.

8.63 After further consideration our draft decision is to retain the section 53N requirements in the main body of the determinations, but to clarify where provisions in the determination are included for the purposes of the price-path. This achieves largely the same outcome, but with fewer changes to the determination's structure.

8.64 The attached draft determinations illustrate the effect of this decision.

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[134] Commerce Commission "Default price-quality paths for gas pipeline services from 1 October 2017: Policy for setting price paths and quality standards" (30 August 2016), para 6.7.

Attachment A Key steps in the process to date

A1 Table A1 below sets out the key steps in the process to date.

Table A1 Key process steps to date

Publication/event	Timing
8 December 2015	Gas stakeholder workshop
28 January 2016	Submissions on industry workshop
29 February 2016	Process and issues paper
10 March 2016	Question and answer session on the process and issues paper
30 March 2016	Submissions on the process and issues paper
13 April 2016	Cross submissions on the process and issues paper
28 June 2016	IM implementation paper
July 2016	Stakeholder meetings on the IM implementation paper
4 August 2016	Submissions on IM implementation paper
18 August 2016	Cross submissions on IM implementation paper
30 August 2016	Policy paper
14 September 2016	Question and answer session on the policy paper
28 September 2016	Submissions on policy paper
12 October 2016	Cross submissions on policy paper
1 November 2016	Supplier update on forecasting expenditure approach

Attachment B Impact of input methodologies review

Purpose

B1 This attachment sets out the IM decisions affecting GPBs that we changed as part of the recent IM review.[135]

Input methodologies changes

B2 The tables below set out how changes we made to the IMs for GPBs in the IM review:

B2.1 impact how we set starting prices for the Gas DPP 2017 reset (Table B1);

B2.2 impact aspects of the DPP, but not how we set starting prices (Table B2); and

B2.3 do not impact the Gas DPP 2017 reset (Table B3).

B3 The decision numbers in the tables are referenced to the IM Report on the Review.[136]

B4 The changes to the IMs are given effect through the IM amendments determinations.[137] The timing of the implementation of the relevant IM determination changes is set out in clause 1.1.2(4) of the respective determinations.

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[135] Commerce Commission "Input methodologies review decisions - Report on the IM review" (20 December 2016). A further review of the IM provisions on related party transactions is still to be completed and is not expected to impact the gas DPP 2017 reset.

[136] Commerce Commission "Input methodologies review decisions - Report on the IM review", Attachment A (20 December 2016).

[137] *Gas Distribution Services Input Methodologies Amendments Determination 2016* [2016] NZCC 25 (20 December 2016) and *Gas Transmission Services Input Methodologies Amendments Determination 2016* [2016] NZCC 26 (20 December 2016).

Table B1 Changes to IMs for GPBs that impact how we set starting prices for the DPP

Decision	Short title (amended if applicable)	Impact on the DPP
CC03	Commission to publish annual WACC estimates	Changes impact on the WACC and cost of debt values used in our DPP financial modelling
CC05	Cost of debt in WACC estimates	Changes impact on the WACC and cost of debt values used in our DPP financial modelling
CC06	Term credit spread differential allowance may apply	Changes how the TCSD allowances are calculated
CC07	Cost of equity in WACC estimates	Changes impact on the WACC and cost of equity values used in our DPP financial modelling
SP02	Total revenue cap applies – GTBs	GTBs are now subject to a 'pure' revenue cap
SP07	Recoverable costs – GTBs	Compressor fuel used in compressors on the Maui pipeline is now recoverable, and has been excluded from opex forecasts

Table B2 Changes to IMs for GPBs which impact the DPP during the regulatory period

SP03	Pass-through costs – EDBs and GDBs	Criteria-based pass-through costs can now be included in the DPP at the start of the regulatory period
SP04	Pass-through costs – GTBs	Criteria-based pass-through costs can now be included in the DPP at the start of the regulatory period
SP06	Recoverable costs – GDBs	The DPP now includes a wash-up for the difference between forecast and actual capex for the year or years preceding the DPP reset
		GDBs may recover prudently incurred expenditure in response to a catastrophic event, prior to any reconsideration of the price-quality path (ie, an amendment of the DPP or an application for a CPP)
		GDBs may recover prudently incurred expenditure in response to an urgent project
SP07	Recoverable costs – GTBs	As for GDBs, and additionally a new recoverable cost to implement the draw-down of the revenue cap wash-up balance
RP01	Reconsideration of DPP	DPP may now be reconsidered due to an 'error' under a wider range of circumstances
		DPP may now be reconsidered in response to a major transaction
RP03	Meaning of 'material' for purposes of reconsideration	Materiality threshold clarified. DPP may now be reopened for a change event where the IMs have become unworkable
RP04	Reconsideration for contingent or unforeseen expenditure under a CPP – GTBs	Availability of this reconsideration provision for CPPs is part of our reason for seeing a CPP as an appropriate option for First Gas' capital expenditure plans
IR08	IRIS to apply under a CPP – GDBs and GTBs	There is no IRIS for GPBs
IR09	Treatment of IRIS balances – GDBs and GTBs	There is no IRIS for GPBs
IR10	Five-year retention of efficiency gains	There is no IRIS for GPBs

Table B3 Changes to IMs for GPBs which do not impact the Gas DPP 2017 reset

Decision	Short title	Reason there is no impact
CA02	Allocating not directly attributable cost	Changes do not come into effect until after the 2022 Gas DPP reset
CA03	Process for deciding allocation approach	Changes do not come into effect until after the 2022 Gas DPP reset
CA04	ABAA causal relationship approach and proxy allocators	Changes do not come into effect until after the 2022 Gas DPP reset
AV09	Capital contributions	No change for 2017 DPP draft We have asked suppliers whether their AMP forecasts and historic ID value of commissioned assets data include capital contributions for asset acquisitions
AV12	Assets purchased from regulated supplier	No impact on 2017 DPP reset financial model
AV13	Financing costs on works under construction – excludes exempt EDBs	Change affects ID and CPPs only
AV17	Standard asset lives apply – with listed exceptions	No change for DPP For the purposes of ID, we have asked Vector and First Gas to confirm whether assets transferred were all done consistently with generally accepted accounting practice
AV54	Initial RAB value – Powerco GDB	Change is to definition of MDL years. No impact on DPP
TX01	Modified deferred tax approach applies – EDBs and GDBs	Change affects ID and CPPs only
TX04	Regulatory tax asset value of asset acquired	Change affects ID and CPPs only
TX08	Tax legislation and cost allocation to be applied – GDBs and GTBs	Clarification and consistency only. No financial model change
RP02	Reconsideration of CPP	Change is for CPPs only

Attachment C Key expenditure forecasting issues

Purpose

C1 This attachment summarises our consideration of the key issues about our approach to forecasting expenditure that were raised in submissions on our policy paper.

Policy paper consultation

C2 In our policy paper, we discussed several proposed changes and potential options for the 2017 GPB DPPs.[138] The policy paper included a discussion on the changes in approach from the 2013 GPB DPPs and also referred to two relevant papers that we published in February 2016. Those papers were the DPP/CPP emerging views paper and the 2017 GPB DPP reset process and issues paper.

C3 In the policy paper, we set out our proposed approach and the assessment framework. We also published Strata Consultants' report and held a question and answer session with interested stakeholders.[139] Following the question and answer session, we received several submissions and cross submissions from stakeholders.

C4 Powerco was concerned that the current consultation timetable did not allow for material changes to the approach, or further engagement with suppliers before the draft decision.[140] Powerco also set out an alternative approach and requested that this be worked through before Christmas 2016. We did not consider Powerco's alternative approach in a parallel process, but instead considered the various aspects of the alternative approach in the same manner as our consideration of all submissions.

C5 We note Powerco's comments about the pilot study that we undertook on our initial low-cost review framework for expenditure.[141] We reiterate that the purpose of the pilot was to test and demonstrate elements of the dashboard and framework to better understand the cost of the proposed process and to aid the consultation process with all interested parties.

C6 After considering the submissions, we made several changes to our approach to forecasting expenditure. These changes were made to deal with the substantive issues raised in submissions. We also noted that greater clarity of our framework was required. We published the updated framework on 1 November 2016 to show

[138] Commerce Commission "Default price-quality paths for gas pipeline services from 1 October 2017—Policy for setting price paths and quality standards" (30 August 2016).

[139] Commerce Commission "Gas DPP Reset 2017—Summary of question and answer session 14 September 2016" (22 September 2016).

[140] Powerco "Submission on Policy for setting price paths and quality standards: Default price-quality paths for gas pipeline services from 1 October 2017" (28 September 2016) paras 83–90.

[141] A report on the pilot study was published in August 2016: Strata Energy Consulting "Low cost review framework for gas pipeline expenditure" (30 August 2016).

the likely changes to our expenditure forecasting approach, as well as provide interim clarification before this draft decision reasons paper.[142]

C7 The key issues on expenditure forecasting raised in submissions on our policy paper were:

C7.1 the perceived high cost of our approach;

C7.2 the level of discretion we exercised (including business-as-usual tolerances and fall-back positions);

C7.3 use of the CPP expenditure objective;

C7.4 suppliers did not prepare AMPs for this purpose;

C7.5 assessment should be done in aggregate, not by category;

C7.6 base level of expenditure should be a multi-year average;

C7.7 information for supplier scrutiny may not be available; and

C7.8 disagreement on the metrics and ratios used.

C8 We have responded to each of these issues below.

The perceived high cost of our approach

C9 One particular objection to the framework set out in our policy paper was a concern that, were we to proceed with this approach, the DPP would move too close to a CPP in its cost and complexity.

C10 GasNet stated that:

> We do not accept that this means any method of setting the DPP would meet the relatively low-cost standard provided it is at least slightly cheaper than a (very expensive) CPP. A DPP methodology should be orders of magnitude lower cost than a CPP, as the method used at the last DPP reset was. We would not support a DPP method that is notably more expensive than the previous DPP method.[143]

C11 Vector and Powerco raised similar concerns about the perceived increased cost of our proposal.[144]

C12 Our intention in implementing an approach based on AMP scrutiny was not, and is not, to replicate a CPP-like process within a DPP. With the modifications and

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142 Commerce Commission "Gas default price-quality path reset 2017—Current views on forecasting expenditure" (31 October 2016).

143 GasNet "Submission on Gas DPP policy paper" (28 September 2016) para 9.

144 Powerco "Submission on Gas DPP policy paper" (28 September 2016), para 41; Vector "Submission on Gas DPP policy paper" (28 September 2016), paras 31-36.

clarifications we have made, we are satisfied that the process is well below the cost of a CPP.[145]

The level of discretion exercised by the Commission

C13 The policy paper was intended to sketch the broad outlines of our approach, and in several cases did not specify with certainty the options we were proposing. Suppliers were especially concerned about:

C13.1 the BAU variance thresholds above historic levels of opex and capex that we would use to 'screen' expenditure for further scrutiny;[146]

C13.2 the types of evidence we would seek as part of supplier scrutiny;[147] and

C13.3 the fall-back positions we would default to where we did not consider expenditure was supported in AMPs or by more evidence.[148]

C14 In not specifying the details of the options for expenditure forecasting early in the process, we intended to first focus consultation on the broad concept of relying on supplier forecasts. This may have given the impression that we were considering using much more discretion than we intended because we did not propose specific parameters to apply across all suppliers. We published our interim forecasting update to allay these concerns by providing more detail about these parameters.

C15 We have provided more detail on these parameters and how they are applied consistently across all suppliers in paragraphs 4.11 to 4.60.

C16 GasNet submitted that:

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[145] The only electricity distributor or gas pipeline to apply for a CPP so far has been Orion. Orion's CPP cost approximately $5m, about half of which was recovered through a recoverable cost. Some submitters have said in other consultations that this understates the cost of a CPP application, although we also believe that future CPP applications may cost less.

[146] Orion "Submission on Gas DPP policy paper" (28 September 2016), para 29; First Gas "Submission on Gas DPP policy paper" (28 September 2016), page 2; Vector "Submission on Gas DPP policy paper" (28September 2016), para 22 and 30.

[147] Orion "Submission on Gas DPP policy paper" (28 September 2016), para 26; First Gas "Submission on Gas DPP policy paper" (28 September 2016), page 3; Powerco "Submission on Gas DPP policy paper" (28 September 2016) para 78-80; GasNet "Submission on Gas DPP policy paper" (28 September 2016), para 12; Vector "Submission on Gas DPP policy paper" (28 September 2016) para 34.

[148] Orion "Submission on Gas DPP policy paper" (28 September 2016), para 29.7; First Gas "Submission on Gas DPP policy paper" (28 September 2016), p. 4; GasNet "Submission on Gas DPP policy paper" (28 September 2016), para 28; Vector "Submission on Gas DPP policy paper" (28 September 2016) para 32.

> AMP and supplier scrutiny should be applied in a manner that is consistent with the proportionate scrutiny principle – i.e. it should take account of the relative size of the business and expect that smaller businesses may have a lesser degree of explanation available (particularly where AMPs are still transitional).[149]

C17 We disagree that the level of explanation required for smaller businesses should be less. We have applied the proportionate scrutiny principle to the supplier evidence test, although we apply this on the basis of the nature of the expenditure (including the impact on price), regardless of the overall size of the supplier.

Suppliers did not prepare AMPs for this purpose

C18 Several suppliers submitted that their AMPs were not prepared with this particular expenditure forecasting process in mind, and that their AMPs are not intended to have the level of explanation of expenditure forecasting that our AMP evidence step requires.[150] This is primarily for the metrics and ratios and the explanation of any significant expenditure variances. For example, Powerco submitted that:

> the current AMPs were not drafted with that comparison against metrics subsequently set in mind – and for that reason, this “AMP scrutiny” stage is highly likely to lead to the next “supplier scrutiny stage”.[151]

C19 We disagree with this, and in practice several areas of expenditure that were above the variance tests were accepted as ‘supported expenditure’ on the basis of the information in the AMPs. For example, Powerco's AMP provided sufficient information for the 'system growth planning capex' and 'asset replacement and renewal planning' areas of expenditure to be accepted without more supplier evidence.

C20 Orion submitted that:

> The approach will incentivise suppliers to place more effort in developing justifications for their expenditure forecasts, both within their AMPs and other documents. A plausible outcome is that the dashboard will be included in the AMP process (and possibly in the document) and any areas that seem higher than BAU will receive additional explanation. Much of the additional explanation will also need to explain historical expenditure shifts (as this is what the Commission’s assessment seems to focus on) which is inconsistent with the forward-looking nature of the AMPs.

C21 In line with Orion's submissions, we expect that AMPs will continue to improve and that this improvement will include better explanation of significant expenditure

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[149] GasNet "Submission on Gas Pipeline Services 2017 DPP policy paper" (28 September 2016) para 32.

[150] Powerco "Submission on Policy for setting price paths and quality standards: Default price-quality paths for gas pipeline services from 1 October 2017" (28 September 2016) paras 66 and 72–74; First Gas "Submission on policy for setting price paths and quality standards in DPP for gas pipeline services from 1 October 2017" (28 September 2016) page 3; GasNet "Submission on Gas Pipeline Services 2017 DPP policy paper" (28 September 2016) para 11; and Vector "Submission to Commerce Commission on gas pipeline business default price-quality path reset" (28 September 2016) para 21.

[151] Powerco "Submission on Policy for setting price paths and quality standards: Default price-quality paths for gas pipeline services from 1 October 2017" (28 September 2016) para 74.

variances and where expenditure may appear inconsistent with other data in the AMPs.

Assessment should be done in aggregate, not by category

C22 Several submitters suggested that more emphasis should be placed on assessing supplier forecasts at an aggregate opex and capex level, instead of the individual areas of expenditure reported under our ID requirements.[152]

C23 As the purpose of the policy paper was a reasonably broad introduction of the approach, it was not clear how much emphasis would be put on aggregate opex and capex. For the draft decision we have provided a clear explanation in paragraphs 4.16 to 4.23, which is that we have used aggregate opex and capex as the first variance test, accepting opex and capex as 'supported expenditure' at an aggregate level if it is less than 5% or 10% respectively above the historic baseline for that supplier.

C24 We consider that we have focused on more material changes by doing the assessment in aggregate as an initial step, followed by analysis of individual areas of expenditure if the aggregate is above the variance test. This is an appropriate implementation of our principle of proportionate scrutiny.

Base level of expenditure should be a multi-year average

C25 In the dashboard that we published at the same time as the policy paper, we used a lowest single year as a baseline for comparing against supplier forecast expenditure. The ENA submitted that the lowest year is likely to be an extreme, and so not a good guide as a reasonable level of expenditure.[153] First Gas also submitted that:

> In the case of our GTB, however, scale factors are largely irrelevant while expenditures are more lumpy and difficult to predict from year to year. In that case the results from comparing expenditures on an annual basis with reference to a single base year are unlikely to provide the most useful guidance. An appropriate approach for our GTB would be to compare expenditure forecasts over a multi-year period against historical expenditures over a multi-year period.[154]

C26 We generally agree with these submissions and have introduced a multi-year average to serve as a historic baseline. This is described in paragraphs 4.24 to 4.27.

Information for supplier scrutiny may not be available

C27 All of the suppliers expressed concern in their submissions on our policy paper that the information requirements for the supplier evidence test may be too high or

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152 Orion "Submission on Gas DPP reset 2017 Policy paper" (28 September 2016) para 29; and Vector "Submission to Commerce Commission on gas pipeline business default price-quality path reset" (28 September 2016) para 23.

153 ENA "Default price-quality paths for gas pipeline services from 1 October 2017—Submission to the Commerce Commission" (28 September 2016) para 18.

154 First Gas "Submission on policy for setting price paths and quality standards in DPP for gas pipeline services from 1 October 2017" (28 September 2016) page 2.

unrealistic.[155] In particular, submissions focused on the availability of appropriate business cases or board papers, which we used as examples of appropriate information in the policy paper. Submitters such as GasNet explained that these types of documents are not available for expenditure that is forecast for later years of the proposed regulatory period.

C28 We accept that board papers and business cases will not be available for all areas of expenditure that reach the supplier evidence test. These were only given as examples of the types of information that may be available. These types of documents may not appropriately answer the specific aspect of the expenditure that we have questioned based on our assessment of the AMPs.

C29 For the draft decision we have accepted expenditure in some cases under the supplier evidence test based on high-level responses by suppliers if we judged them to be sufficient. All of the responses provided by suppliers in the supplier evidence tests have been published alongside our draft decision.

Disagreement on the metrics and ratios used

C30 We discussed the use of metrics and ratios in the policy paper as a new approach to assessing supplier forecasts. We explained that we wanted to understand:

C30.1 how accurate forecasts have been compared to actual expenditure;

C30.2 what cost drivers are contributing to forecast expenditure;

C30.3 what efficiency gains were being achieved per ICP over time; and

C30.4 if asset replacement is occurring at an appropriate level.

C31 Our view was that the use of metrics and ratios would be a relatively low-cost means to begin to understand these factors. Also, we considered that using metrics and ratios would test a supplier's forecast accuracy, while highlighting the relationship to cost drivers (both inputs and outputs), such as gas volumes and ICP numbers.

Policy paper submissions—metrics and ratios

C32 In the policy paper we signalled that we were seeking feedback on the metrics and ratios, and how these might be used to assess supplier forecasts. Many submitters had general concerns about the use of ratio analysis and also about specific metrics and ratios, and their relevance to supplier business practices.

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155 Orion "Submission on Gas DPP reset 2017 Policy paper" (28 September 2016) paras 26; Powerco "Submission on Policy for setting price paths and quality standards: Default price-quality paths for gas pipeline services from 1 October 2017" (28 September 2016) paras 78–90; First Gas "Submission on policy for setting price paths and quality standards in DPP for gas pipeline services from 1 October 2017" (28 September 2016) page 3; GasNet "Submission on Gas Pipeline Services 2017 DPP policy paper" (28 September 2016) para 12; and Vector "Submission to Commerce Commission on gas pipeline business default price-quality path reset" (28 September 2016) para 34.

C33 Powerco noted that the metrics use arbitrary forecasts and do not consider the drivers for costs for GDBs, while GasNet noted that it does not consider all metrics are robust and/or able to inform us about whether expenditure trends are reasonable.[156] GasNet stated that "the Commission appears to be interpreting data in a particular way when other plausible interpretations are available".[157]

C34 First Gas commented that we should review metrics that relate to and drive the variable costs of a business. In its cross submission, Vector agreed with GasNet and Powerco that the use of some uncommon metrics may lead to erroneous conclusions about expenditure efficiency.[158]

C35 In the policy paper, we stated that the metrics were developed to provide a low-cost method of assessing if a GPB's capex and opex forecasts could be considered BAU.

C36 We acknowledge concerns that a metric or ratio that is artificially representative of a business cost driver could create unnecessary work for suppliers if we required them to defend a result or trend that the metric or ratio demonstrated. However, we intend that most metrics and ratios be observed together. While some of these can be viewed in isolation, not all have been used to create an understanding of GPB expenditure forecasts.

C37 Suppliers made specific comments about the following metrics and ratios in submissions:

C37.1 opex to output radar diagram;[159]

C37.2 expenditure per TJ;[160]

C37.3 cost of interruptions;[161]

C37.4 revenue per TJ and revenue per ICP;[162] and

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156 Powerco "Submission on Policy for setting price paths and quality standards: Default price-quality paths for gas pipeline services from 1 October 2017" (28 September 2016) paras 58 and 65; and GasNet "Submission on Gas Pipeline Services 2017 DPP policy paper" (28 September 2016) para 14.

157 GasNet "Submission on Gas Pipeline Services 2017 DPP policy paper" (28 September 2016) para 71.

158 First Gas "Submission on policy for setting price paths and quality standards in DPP for gas pipeline services from 1 October 2017" (28 September 2016) page 3; and Vector "Cross-submission on the Policy Paper for resetting default price-quality paths for gas pipeline services from 1 October 2017" (12 October 2016) para 10.

159 GasNet "Submission on Gas Pipeline Services 2017 DPP policy paper" (28 September 2016) paras 72–74; and Orion "Submission on Gas DPP reset 2017 Policy paper" (28 September 2016) para 29.5.

160 Powerco "Submission on Policy for setting price paths and quality standards: Default price-quality paths for gas pipeline services from 1 October 2017" (28 September 2016) Appendix 1, page 31.

161 GasNet "Submission on Gas Pipeline Services 2017 DPP policy paper" (28 September 2016) para 76; and Powerco "Submission on Policy for setting price paths and quality standards: Default price-quality paths for gas pipeline services from 1 October 2017" (28 September 2016) Appendix 1, pages 31–32.

162 Powerco "Submission on Policy for setting price paths and quality standards: Default price-quality paths for gas pipeline services from 1 October 2017" (28 September 2016) Appendix 1, pages 31–32.

C37.5 capex and opex variation per ICP and per total gas supplied.[162]

C38 Following the supplier feedback, and with our consultant Strata, the metrics and ratios were refined from those in the dashboard prototype, outlined in the policy paper. The refined set of metrics and ratios are those which only explain why expenditure forecasts may be increasing or decreasing, relying solely on information from ID requirements. The current metrics are used to:

C38.1 demonstrate the drivers for asset replacement and renewal;

C38.2 demonstrate the key drivers of consumer connection and system growth capex – volume of gas supplied or forecast to be supplied, the number of ICPs connected, the length of the pipelines or systems used to meet demand, compared to capex and opex;

C38.3 consider total expenditure compared to gigajoules of gas delivered (historic and forecast);

C38.4 compare opex levels to output (comprising annual GJ supplied per ICP) at a total level and for relevant individual categories of opex;

C38.5 demonstrate opex compared to asset value as an alternative to output;

C38.6 assess the cost of interruptions forecast – service interruptions, incidents and emergencies opex compared to total annual forecast planned and unplanned interruptions;

C38.7 compare historic opex to forecast; and

C38.8 compare historic capex to forecast.

C39 We consider that the metrics and ratios have informed the supplier forecasting process, where AMP information was sought to support non-BAU expenditure, and when this was not sufficient, enabled us to ask specific clarification questions of suppliers to supplement the AMP information. Using this metric and ratio approach to assess supplier forecasts and AMPs has permitted us to understand the cost drivers of each supplier business in an efficient and low-cost way.

C40 There has been support of the approach particularly from MGUG who comment that "the quantitative and qualitative assessments of how suppliers' forecasts differ from a baseline "business as usual" expenditure appears to us to be a pragmatic and low-cost approach to assessing whether forecasts are reasonable in context".[163]

C41 Some submitters suggest extending the metric and ratio approach to benchmark GPBs against each other. However, Powerco disagrees with MGUG that

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[163] MGUG "Gas DPP reset 2017-Policy for setting price paths and quality standards for gas pipeline services" (28 September 2016) paras 13–14.

benchmarking should be used to create downward price pressure on GPBs.[164] We are unable to take into account comparative benchmarking analysis when we set prices in the DPP.[165]

[164] MGUG "Gas DPP reset 2017-Policy for setting price paths and quality standards for gas pipeline services" (28 September 2016) paras 13–14; and First Gas "Cross-submission on policy for setting price paths and quality standards in DPP for gas pipeline services from 1 October 2017" (12 October 2016) page 3.
[165] Section 53P(10) of the Commerce Act.

Attachment D Expenditure forecast table

Purpose

D1 This attachment shows our draft expenditure forecasts for the 2017 DPP, based on our assessment of suppliers' forecasts by area of expenditure.

Table D1 Our forecast for the proposed regulatory period (in real 2016 $'000s)

Expenditure	First Gas transmission	GasNet	Powerco	Vector	First Gas distribution	Total
Asset relocation	1,592	98	84	627	694	3,095
Asset replacement and renewal	55,599	1,975	13,950	7,639	18,146	97,309
Consumer connections	5,975	525	16,888	63,322	9,820	96,531
Non-network assets	16,879	531	5,708	6,429	1,902	31,450
System growth	13,909	513	8,333	5,618	3,352	31,723
Reliability, safety and environment	0	406	21,606	1,894	0	23,906
CAPEX TOTAL	**93,954**	**4,048**	**66,568**	**85,530**	**33,915**	**284,014**
Asset replacement and renewal	0	0	15,044	0	0	15,044
Business support	61,021	3,825	33,369	20,790	8,198	127,203
Routine and corrective maintenance and inspection	71,170	425	10,336	12,305	9,231	103,467
Service interruptions, incidents and emergencies	3,261	300	2,073	9,785	11,353	26,771
System operations and network support	36,447	3,400	20,681	13,476	6,437	80,441
Compressor fuel	22,000	N/A	N/A	N/A	N/A	22,000
Land management and other activities	3,704	N/A	N/A	N/A	N/A	3,704
OPEX TOTAL	**197,602**	**7,950**	**81,503**	**56,355**	**35,219**	**378,629**
TOTAL	**291,556**	**11,998**	**148,071**	**141,885**	**69,134**	**662,644**

Attachment E Adjustments for changes in economies of scale

Purpose

E1 This attachment describes how we considered and identified efficiency gains and losses from changes in economies of scale that resulted from the industry transactions involving First Gas, Vector, and MDL.[166]

We have not identified any economies of scale gain from the transmission merger

E2 For the draft decision, we have not identified any clear efficiency gain by First Gas resulting from the transmission merger of the Vector and MDL transmission pipelines. We analysed and compared the following areas of opex in First Gas' forecast, the historic level of expenditure on the transmission network, and the 2014 forecasts of Vector transmission and MDL:

E2.1 non-network;

E2.2 services, interruptions, incidents and emergencies;

E2.3 routine and corrective maintenance and inspection; and

E2.4 asset replacement and renewal.

E3 The expenditure categories 'business support' and 'system operations and network support' were combined into a non-network sub-total because it appears that the different businesses have used different definitions of these sub-categories. The allocation of non-network opex between the sub-categories has been inconsistent in the past.

E4 We have focused our analysis on these categories because we consider that they are the categories of expenditure most likely to be significantly impacted by economies of scale.

E5 The forecast of expenditure by First Gas for non-network opex is slightly lower than the recent combined total of Vector and MDL transmission. However, this is more than offset by the other categories of opex. It may also be the case that the temporary spike in opex in 2017 is a result of the merger.

E6 The forecast made by First Gas for the proposed regulatory period is lower than the combined forecasts of Vector transmission and MDL. However, the combined forecasts of Vector and MDL were significantly higher for the period than the

[166] First Gas bought the two gas transmission pipelines in New Zealand in 2016 from MDL and Vector. At the same time as purchasing the transmission pipeline from Vector, First Gas also purchased Vector's non-Auckland gas distribution network.

outturn expenditure. This means that the lower forecast by First Gas is not in itself an indicator that there is gain in economies of scale.

E7 The expenditure forecasts published by the previous owners of the transmission pipelines include a large increase in the last year of the proposed regulatory period, which is not included by First Gas. However, we do not consider that this is clear evidence of a forecast efficiency gain by First Gas because there is no clear explanation for the previously forecast increase in the AMPs. Also, this increase was less reliable as it was for 7-9 years after the previous AMPs were written.

E8 We do not see any clear indication of an efficiency gain from the merger being included in the forecast expenditure. For our final decision, we will consider any submissions with more evidence on any efficiency gains from increased economies of scale from the merger that are included in the expenditure forecasts.

We have not yet identified economies of scale effects in the sale of the Bay of Plenty expansion

E9 We have not yet identified any economies of scale effects from the sale of the Bay of Plenty assets. The sale from GasNet to First Gas was very small relative to the overall size of both GasNet and First Gas, so the effects on economies of scale would be relatively small in relation to our reset of the DPPs. Any small economies of scale gains by First Gas might be offset by economies of scale losses by GasNet.

We have identified some economies of scale losses in the Vector distribution business

E10 We have subtracted the increased expenditure that we have identified from our forecast. This means that the increased expenditure caused by the loss of economies of scale impacts on Vector's profitability rather than consumers' prices. That is to say, Vector will not be compensated in the proposed regulatory period for additional expenditure that is only required because of the sale of part of its business to First Gas. We have not made an adjustment to First Gas distribution because we have not identified an efficiency loss in First Gas' expenditure forecasts.

Economies of scale loss—opex

E11 The total network opex across the First Gas and Vector distribution networks is forecast by the suppliers to be similar during the proposed regulatory period to what it was before part of the network was sold to First Gas. This suggests that there is unlikely to be a significant loss of efficiency due to the split included in the forecast expenditure. The expenditure in this category forecast by the new suppliers is less than the forecast that was made by Vector in 2015 before the network split.

E12 However, the total non-network opex across the First Gas and Vector distribution networks is forecast by the suppliers to be significantly higher during the proposed regulatory period than it was reported to be in the 2013-2015 IDs. We believe that this is evidence of an efficiency loss caused by reduced economies of scale.

E13 We also considered the changes in non-network opex by each of the two relevant suppliers. We did this by hypothetically splitting the historic expenditure of the original Vector distribution business into the two new networks using the expenditure proportions provided by the two suppliers for 2016.[167]

E14 The increase in supplier forecast non-network opex is predominantly caused by Vector distribution, which forecast significant increases in both the 'business support' and 'system operations and network support' areas of expenditure. First Gas did forecast an increase in the 'system operations and network support' area of expenditure, but this is offset by a significant decrease in the 'business support' area of expenditure.

E15 High levels of non-network opex in these situations could be caused by an unreasonably high supplier forecast rather than a loss of economies of scale. However, Vector distribution also stated in its latest AMP that: [168]

> Despite the reduction in Vector's overall corporate cost base, the quantum of this cost allocated to Vector's Auckland gas network has increased directly as a result of the sale. This is due to loss of significant economies of scale that Vector enjoyed in managing multiple networks. A number of the corporate functions undertaken by Vector will not scale as a result of the sale of Vector Gas, for example the Vector board and executive team will remain unchanged and the regulatory compliance burden associated with gas distribution will not change despite the fact that our gas distribution business is now significantly smaller.

E16 Without more evidence, a multi-year average of historic expenditure is the best available baseline to use to calculate the adjustment for areas of expenditure that we consider suffered a loss of efficiency due to reduced economies of scale. Given that we have forecast the non-network expenditure for Vector distribution using the fall-back option, the adjustment to the starting prices was based on the difference between the fall-back position and the historic multi-year average. This difference is $1.6m (in 2016 real dollars) over the proposed regulatory period.

Economies of scale loss—capex

E17 While our focus of analysis was on opex, Vector Distribution noted changes to its forecast capex in 2016 due to reduced economies of scale in its latest AMP:

> $0.2 million per annum increase in non-network costs due largely to the proportionally greater resources necessary to support the business given the lost economies of scale from the sale of Vector's gas transmission and non-Auckland gas distribution networks.[169]

E18 This is a clearly identified impact of the reduced economies of scale. We have reduced the forecast of non-network capex for Vector to the average of its historic baseline expenditure because subtracting the full $0.2m would result in a forecast

[167] The expenditure proportions were calculated from the responses to our 53zd request for information from gas pipeline service suppliers, which are published alongside this reasons paper.
[168] Vector "Gas Distribution Asset Management Plan 2016 – 2026" (August 2016) section 1, page 7.
[169] Vector "Gas Distribution Asset Management Plan 2016 – 2026" (August 2016) section 9, page 6.

below the historic baseline. The adjustment is a reduction of $0.6m over the five-year regulatory period.

Further considering this adjustment in the final decision

E19 For the final decision, we will consider any submissions with more evidence on why the adjustment for efficiency losses due to decreased economies of scale should be greater or less than what we have decided in the draft decision. We have considered the adjustments for economies of scale separately to our approach to forecasting expenditure. The level of evidence required to change our draft position is greater for economies of scale than for supplier evidence for expenditure forecasting.

E20 We will update our analysis and calculation of the adjustment by using the 2016 historic expenditure data in the historic average. We will consider any changes to our forecast of expenditure (for example, the adjustment may be increased if we increase our forecast of Vector distribution's expenditure).

Attachment F Price setting and wash-up processes for the pure revenue cap

Purpose

F1 This attachment sets out our draft decisions relating to the price setting and wash-up processes to be applied by the GTB.

Introduction

F2 The IM for GTBs provides that the form of control must be a pure revenue cap with a wash-up of under and over-recovery of revenue.[170] The purpose of the wash-up is to ensure that revenue is not under or over recovered over time.

F3 Implementing the revenue cap wash-up takes place through the price setting and wash-up processes discussed in this attachment. We set out below our draft decisions on the price setting and the wash-up processes under the following headings:

F3.1 Process sequence and timing

F3.2 Price setting process and assessing compliance

F3.3 Wash-up calculation

Summary of decisions

F4 The GTB IM sets out requirements for the specification of price, and provides for several decisions to be made as part of the DPP reset process. Key decisions taken as part of the DPP draft decision are:

F4.1 IM Clause 3.1.1(2) allows a maximum percentage increase in forecast allowable revenue to be specified as a function of demand in each assessment period's price setting if this is determined in the DPP Determination. We have chosen to specify such an annual maximum, and have set this ‘average price increase limit’ to 10% in real terms.

F4.2 IM Clause 3.1.1(5) provides in effect for the DPP Determination to specify how this average price increase limit must be calculated. This is discussed in paragraphs F22 to F43.

F4.3 For calculating the actual allowable revenue and for calculating the closing wash-up account balance, the revenue account draw-down amount has been set to the opening balance of the wash-up account. This means that actual allowable revenue is set each assessment period based on fully

[170] Gas Transmission Services Input Methodologies Amendments Determination 2016.

drawing down the wash-up balance. This is discussed in paragraphs F44 to F48.

Process sequence and timing

F5 In this section we set out the sequence and timing of the price setting, compliance assessment and wash-up calculations. Figure F1 sets out the price setting and compliance setting process and Figure F2 sets out the wash-up calculations. These figures are at the end of this attachment.

First and second assessment periods of the regulatory period

F6 Only the price setting process and assessing compliance will be performed when setting prices for the first and second assessment periods of the regulatory period, because there will be no prior assessment period for which a wash-up calculation is to be taken into account.

Third and subsequent assessment periods of the regulatory period

F7 When setting prices for the third, fourth, and fifth assessment periods of the regulatory period, a wash-up calculation of a prior assessment period will need to be taken into account when setting prices for the forthcoming assessment period. Three consecutive assessment periods will feature in each of these calculations. For this attachment we define names for each of these three assessment periods as follows:

F7.1 the ‘assessment period to be washed up’, will be the earliest of these three assessment periods;

F7.2 the ‘calculation assessment period’, will be the second of these three assessment periods;[171] and

F7.3 the ‘assessment period for which prices are to be set’, will be the last of these three assessment periods.

F8 The table below shows the three consecutive assessment periods. For the calculation assessment period it shows that this assessment period comprises four phases:

F8.1 waiting for data from the prior assessment period (such as quantities supplied) to become available;

F8.2 doing the wash-up calculation;

F8.3 with the results of the wash-up calculation available, setting prices for the subsequent assessment period; and

[171] Prices are calculated, set and notified by the GTB in advance of the assessment period in which those prices apply.

F8.4 the notice period for prices, being from the time that finalised prices are published to the time they take effect.

Table F1 Process timeline

Assessment period to be washed up	Calculation assessment period				Assessment period for which prices are to be set
	Waiting for data from prior assessment period	Wash-up of prior assessment period	Price setting for forthcoming assessment period	Notice period for prices	

F9 For example, for setting prices that apply in the third assessment period of the regulatory period (ie, the assessment period ending September 2020), the assessment period to be washed up will be the first assessment period, ie, the assessment period ending September 2018. The calculation assessment period will be the assessment period ending September 2019. The assessment period for which prices are to be set will be the assessment period ending September 2020.

F10 A few months into the calculation assessment period, the information necessary to perform the wash-up calculations for the assessment period to be washed up will be available. This information would include:

F10.1 actual quantities of services provided in the assessment period to be washed up;

F10.2 prices;

F10.3 actual pass-through and recoverable costs;

F10.4 actual CPI values for the calculation of actual net allowable revenue; and

F10.5 other regulated income received.

F11 The wash-up calculation can then be performed. The wash-up amount for the assessment period to be washed up will be calculated, and from this the closing wash-up balance can be calculated.

F12 The GTB can then undertake the price setting process for the assessment period for which prices are to be set. This process comprises:

F12.1 forecasting quantities of services provided in the assessment period for which prices are to be set;

F12.2 forecasting pass-through and recoverable costs;

F12.3 calculating the forecast allowable revenue;

F12.4 setting individual prices so that the forecast revenue from these prices is not more than the forecast allowable revenue and the average price increase is less than the limit on the annual average price increase; and

F12.5 determining the draw-down amount (see paragraphs F44 to F48).

Price setting process and assessing compliance

F13 Compliance with the DPP Determination requires forecast allowable revenue to be calculated, and a set of prices to be developed so that the FRP does not exceed the FAR. The FAR includes the recovery of forecast pass-through and recoverable costs. Compliance also requires that prices are set so that a limit on average price increases from one assessment period to the next is not exceeded.

F14 The forecast allowable revenue must be the sum of:

F14.1 the forecast net allowable revenue;

F14.2 the forecast of the pass-through and recoverable costs excluding any draw-down amount; and

F14.3 the opening balance of the wash-up account.[172]

F15 The forecast net allowable revenue will be calculated for each assessment period of the regulatory period by the financial model, so these values will be available when the DPP is set.[173] Each of the five values is listed in Schedule 2 of the DPP Determination. The forecast net allowable revenue is referred to in the financial model as the maximum allowable revenue before tax, or MAR.

F16 A forecast of the pass-through and recoverable costs will be prepared by the GTB during each price setting process. These forecasts will exclude the amount of any draw-down amount (which will itself be a recoverable cost).

F17 The GTB will prepare a forecast of quantities for each of the services supplied.

F18 The GTB will prepare a schedule of prices and forecast quantities. From these the GTB will calculate the FRP as the total of each price multiplied by its corresponding forecast quantity.

F19 FRP must not exceed the forecast allowable revenue for each assessment period. This reflects the requirement in Clause 3.1.1(1) of the IM.

[172] There will be no opening wash-up account balance in the first two assessment periods because there will have been no wash-ups to populate a balance.

[173] The methodology for calculating the forecast net allowable revenue for the second and subsequent assessment periods, given the first assessment period value, is set out in the GTB IM on a CPI-X basis. The financial model applies this methodology. The forecast net allowable revenues for the whole of the regulatory period are specified in Schedule 4 of the determination. This can be done because the forecast CPI values and the forecast net allowable revenues are all set at the time the path is set.

F20 There will be pass-through and recoverable costs from the regulatory period ending 20 September 2017 that will remain unrecovered at the start of that regulatory period.

F21 In the draft decision, we have not made an explicit provision in the calculation of forecast allowable revenue for any pass-through and recoverable costs that remain unrecovered from the regulatory period ending 20 September 2017. These will be provided for in the 'actual allowable revenue' for the first assessment period and will flow to the third assessment period prices via the wash-up mechanism, adjusted for the time value of money (consistent with IM clause 3.1.3(8)(k)).

Limit on the increase in average prices

F22 The IM review final decisions (IM Clause 3.1.1(2)) provide for a limit to be set, as part of a DPP reset, on the increase in average prices from one assessment period to the next. The aim of this limit is to reduce price volatility for consumers.

F23 The draft DPP Determination specifies that such a limit will apply. In the IM, this limit is expressed as a maximum annual percentage increase in 'forecast allowable revenue as a function of demand'. The IM review final decisions provide that the calculation method of the average price increase and its limit would be specified in the relevant DPP or CPP.

F24 The limit will not lead to any permanent loss in revenue for the GTB, as it is intended to be only a price smoothing mechanism. If the limit binds, its impact would increase the wash-up amount for that assessment period.

F25 This increase in the wash-up amount would increase actual allowable revenue two assessment periods later (with a time value of money adjustment). It is through this mechanism that the GTB would not have a permanent loss from the limit.

F26 The level of the limit in the draft decision is 10% in real terms. The level we used in the EDB DPP reset published in 2012 was a 10% increase in real terms to mitigate price shocks between regulatory periods.[174] In the 2015 EDB DPP reset decision, we used a limit of 5% in real terms.[175] We seek feedback from stakeholders on the proposed level of this limit.

F27 The limit on average price increases is intended to mitigate the pricing impact of significant reductions in demand. In addition to this objective, the limit mechanism needs to be robust in the event of a price restructuring.

F28 A significant price restructuring may well result from the replacement of the current Maui Pipeline Operating Code and the Vector Transmission Code with a single

[174] Commerce Commission "Reasons paper for Resetting the 2010-15 Default Price-Quality Paths" (30 November 2012) para 6.7.
[175] Commerce Commission "Main Policy Paper for the 2015 EDB DPP reset" (28 November 2014) para 4.25.

operating code. The code replacement process will have its own consultation process, by either First Gas or the GIC.

F29 It is important that any average price increase limit will be able to be applied and not result in perverse results if such a price restructuring occurs. It is not currently clear to us what the possible pricing structures might be under a future single operating code.

F30 Four main types of quantity are currently used as the basis for charging, as listed in Table F2 below. We refer to the revenue derived from a particular type of quantity as a 'revenue class'. For example, the total revenue derived from capacity reservation fees would be a revenue class.

Table F2 Quantity classes

Class #	Description of charge	Quantity units	Price units
1	Approved nomination (AQ)	GJ of approved nominations	$/GJ nominated
2	AQ times distance transported	GJ.km of approved nominations	$/GJ.km nominated
3	Capacity reservation fee	GJ/day per annum	$/GJ/day per annum
4	Throughput fee	GJ delivered	$/GJ delivered

F31 Our draft decision is, with one exception, for the four revenue classes with the highest revenues to be used in the calculation of the average price increase. We expect that the four revenue classes listed above will initially have the highest revenues. The exception is that if there are less than four revenue classes available in total, then the number of relevant revenue classes would be the lesser number.

F32 We refer to the revenue classes that are to be taken into account as 'relevant revenue classes', and note that these could change as a result of a future price restructuring.

F33 The average price for each of the relevant revenue classes in the table above will need to be calculated. It will be the total revenue from the class divided by the total quantity for that class. When setting prices, this average price would be calculated for the assessment period for which prices are being set, and for the prior assessment period. The ratio of these two estimates will indicate the percentage price increase for that class.

F34 For each of the first two classes in the table above, there is just one tariff set, and that tariff applies to all the quantities in that class. For Class 3, the tariff structure for the former Vector network schedules a 'capacity reservation fee' for each of the many delivery points at which gas is delivered from that network. Similarly, there are many different tariffs for the Class 4 quantities (throughput fees).

F35 In addition to the four charges referred to in Table F2, over-run charges apply to users that use pipeline capacity in excess of the capacity that has been reserved via the 'capacity reservation fee' (Class 3 in Table F2 above). These are listed in Table F3 below.

Table F3 Quantity classes not included in the price increase calculation

Class #	Description of charge	Quantity units	Price units
5	Over-run authorisation charge	Over-run GJ authorised	$/capacity over-run, GJ
6	Authorised over-run charge	Over-run within authorisation, GJ	$/GJ/day
7	Unauthorised over-run charge	Unauthorised over-run, GJ	$/GJ/day

F36 The proposal is to not take account of these over-run charges. Over-run prices are not independently set. They are instead determined by a formula in the Vector Transmission Code, and are a function of the capacity reservation fee.

F37 The overall average price increase would be calculated as the weighted average of the price increases for each relevant revenue class. The weights would be the estimated revenue for each class for the assessment period prior to the one for which prices are being set. This average price increase may be expressed as follows:

$$Average\ Price\ Increase = \sum_{i=1}^{N} \left(\frac{R_{i,t-1}}{R_{tot,t-1}} \times \frac{\left(\frac{R_{i,t}}{Q_{i,t}}\right)}{\left(\frac{R_{i,t-1}}{Q_{i,t-1}}\right)}\right) - 1$$

where:

i refers to the Class number, and takes the values 1 to 4

N is the number of relevant classes, and is the lesser of 4 and the number of revenue classes

t refers to the assessment period for which prices are being set, and t-1 refers to the prior assessment period

$R_{i,t}$ is the revenue from the ith class in assessment period t

$R_{i,t-1}$ is the revenue from the ith class in assessment period t-1

$Q_{i,t}$ is the quantity for the ith class in assessment period t

$R_{tot,t-1}$ is the total revenue from the relevant revenue classes in assessment period t-1

Each of these revenues and quantities will be a forecast, and must be reasonable.

F38 An example calculation is set out below. The input data has a blue background, and is for illustrative purposes only. The values do not bear any relationship to values that are likely to apply.

Table F4 Example calculation of the price increase

	Class #:	1	2	3	4	
		Approved nomination (AQ)	**AQ times distance transported**	**Capacity reservation fee**	**Through put fee**	**Total**
Revenue in year t-1	$R_{i,t-1}$	10	20	50	30	110
Revenue in year t	$R_{i,t}$	11	23	58	33	125
Quantity in year t-1	$Q_{i,t-1}$	100	101	102	103	
Quantity in year t	$Q_{i,t}$	103	104	105	106	
Proportion of revenue	$R_{i,t-1} / R_{tot,t-1}$	9.1%	18.2%	45.5%	27.3%	
Average price in year t	$R_{i,t} / Q_{i,t}$	0.109	0.216	0.552	0.31	
Average price in year t-1	$R_{i,t-1} / Q_{i,t-1}$	0.10	0.198	0.490	0.29	
Price change factor	$(R_{i,t} / Q_{i,t}) / (R_{i,t-1} / Q_{i,t-1})$	1.087	1.093	1.127	1.069	
Weighted price change factor	$(R_{i,t-1} / R_{tot,t-1}) \times (R_{i,t} / Q_{i,t}) / (R_{i,t-1} / Q_{i,t-1})$	0.099	0.199	0.512	0.292	1.101
Price increase	10.1%					

F39 The revenue classes might change with the replacement of the current Maui Pipeline Operating Code and the Vector Transmission Code with a single operating code. If one of the relevant revenue classes ceases to be used for any of the pricing, there would be the potential for the calculation of the average price increase to fail because division by zero could arise in the formula above.

F40 Our draft decision is, when setting prices for an assessment period, to include as a relevant revenue class any revenue class that has ceased to be used in price setting for the first time in that assessment period.

F41 In that first assessment period in which the revenue class will not be used, the revenue for the class shall be set to nil. In all subsequent assessment periods, the revenue class would cease to be a relevant revenue class.

F42 If the price increase mechanism were to cause issues during the regulatory period, a way of dealing with this might be to use the provisions under section 55I(3) if those provisions were to apply.

F43 We invite submissions on our draft decision on the average price increase limit method.

Revenue wash-up draw-down amount

F44 If the GTB has built up a positive balance in its wash-up account, it may use some or all of this balance when setting prices, such that the prices would be higher than if it did not use any of this balance. This is generally referred to as drawing down the account.

F45 For calculating the actual allowable revenue and for calculating the closing wash-up account balance, the revenue account draw-down amount has been set to the opening balance of the wash-up account. This means that actual allowable revenue is set each assessment period based on fully drawing down the wash-up balance.

F46 The requirement to set the draw-down amount equal to the opening balance of the wash-up account does not mean that the GTB must price up to its maximum limit.

F47 The GTB may price lower than it is allowed to. If it does, the extent of any under-charge will increase its wash-up amount for that assessment period. That increase will in turn increase (via the wash-up balance) the actual allowable revenue for the assessment period two assessment periods after prices had been set lower than allowed.

F48 Through this mechanism, the GTB will be able to recover previous under-charging two assessment periods after the lower prices, together with a time value of money adjustment.

Wash-up calculation

Wash-up amount

F49 The under or over-recovery of the allowable revenue will be added to, or subtracted from, the GTB's wash-up account. The under or over-recovery is, with one exception, the difference between the actual allowable revenue and the actual revenue.

F50 Whether the difference is added to, or subtracted from, the wash-up account depends on whether the difference is a positive or negative amount.

F51 The one exception is that if the cap on the wash-up amount binds, then an amount of 'revenue foregone' will be subtracted from the difference to be applied to the wash-up account. It would reflect a sharing of risk between the supplier and consumers when the quantities of services provided are significantly lower than forecast quantities. A cap of 20% of a net allowable revenue amount would in effect apply, as specified in the GTB IM.[176]

[176] Commerce Commission "Input methodologies review decisions - Report on the IM review" (20 December 2016).

F52 More details on the calculating the revenue foregone are set out in the 'Cap on the wash-up amount' section below.

F53 The wash-up amount will be calculated as the actual allowable revenue, less actual revenue, less revenue foregone. This amount, together with a time value of money adjustment on this amount, will be added to the wash-up account each assessment period (see paragraphs F60 to F64).

Actual net allowable revenue

F54 The value of actual net allowable revenue for the first assessment period of the regulatory period is provided in the DPP Determination. For subsequent assessment periods, it is to be calculated on a CPI-X basis from the previous assessment period's value. The actual CPI increase will be required for this calculation. It will be available from Statistics New Zealand in time for the wash-up calculations to be done.

Actual pass-through and recoverable costs

F55 In a similar way, actual values of pass-through and recoverable costs will be available in time for the wash-up calculations during each calculation assessment period.

Actual allowable revenue

F56 The actual allowable revenue will be calculated as the sum of the actual net allowable revenue and the actual pass-through and recoverable costs. The recoverable costs in this instance include the draw-down amount applicable to the assessment period to be washed up.

F57 The actual allowable revenue for the first assessment period only may include an amount to recover pass-through and recoverable costs from the regulatory period ending 30 September 2017 that have not been recovered during that regulatory period.

F58 The amount shall include a time value of money adjustment at a discount rate of 5.38%. This rate is the discount rate specified in the Schedule 6 of the DPP for the regulatory period ending 30 September 2017 for time value of money adjustments in relation to pass-through and recoverable costs.

F59 All of the amounts discussed in this 'wash-up process' section up to this point relate to the assessment period to be washed up. We will now discuss maintaining the balance of the wash-up account.

Maintaining the wash-up account

F60 The relevant assessment period for updating the wash-up account will be the assessment period for which prices are to be set. The opening balance of this account for the second and subsequent assessment periods of the regulatory period will be the closing balance of the previous assessment period.

F61 The closing balance of the wash-up account for the second and subsequent assessment periods will be the wash-up amount for the previous assessment period, plus a time value of adjustment as set out below.

F62 The first entry in the wash-up account will be the closing balance for the second assessment period, and this entry will record the wash-up amount for the first assessment period together with its time value of money adjustment.

F63 The time value of money adjustment relates to the two-year delay between the wash-up amount being incurred and the assessment period in which it will be able to be taken into account in future prices.

F64 The discount rate for the time value of money adjustments will be the 67th percentile estimate of the post-tax WACC as at 1 March 2017. Its value will be set out in the DPP Determination.

Cap on the wash-up amount

F65 As set out in the IMs, there is a cap on the wash-up amount.[177] The aim of this cap is to provide a sharing of risk between the GTB and consumers when the quantities of services provided are significantly lower than forecast quantities.

F66 The difference between FRP and actual revenue from prices reflects how large, on average, is the difference between forecast and actual quantities. The implementation of this cap is through 'revenue foregone', which is the amount of permanent loss the GTB will incur if the cap binds.

F67 Calculating revenue foregone requires another parameter to be defined and determined: the 'revenue reduction percentage'. This reflects the extent to which actual revenues from prices is less than FRP. It is, in turn, the average reduction in quantities between forecast and actual values, using the prices as weights in the weighted average calculation.

F68 The formula for revenue reduction percentage is:

> Revenue reduction percentage = 1 - (actual revenue from prices ÷ forecast revenue from prices)

F69 The formula for revenue foregone is:

> Revenue foregone = actual net allowable revenue × (revenue reduction percentage - 20%), subject to the revenue foregone being nil if revenue reduction percentage is not greater than 20%.

F70 In this formula, the actual net allowable revenue is the value for the assessment period being washed up.

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[177] Commerce Commission "Input Methodologies Review – Topic Paper 1" (20 December 2016), page 34.

F71 This amount of revenue foregone will be subtracted from the amount that would otherwise be the wash-up amount. In other words, the wash-up amount will be actual allowable revenue less actual revenue less revenue foregone. This has the effect of capping the wash-up amount.

Ensuring pass-through and recoverable costs are fully recovered

F72 We have designed the implementation of the IMs to make sure that the cap on the wash-up amount does not prevent pass-through and recoverable costs from being fully passed through and fully recovered.[178]

F73 We have prepared a form of control demonstration model to demonstrate how the wash-up mechanism would work in practice and to demonstrate that pass-through and recoverable costs may be fully recovered, both when the amount of revenue foregone is nil and when it is not. The model will be released during the consultation period.

[178] Refer para 156 on page 36 in Input methodologies review decisions - Topic paper 1, Commerce Commission, 20 December 2016.

Flow charts

Figure F1

Setting prices and assessing compliance for Year t for a GTB

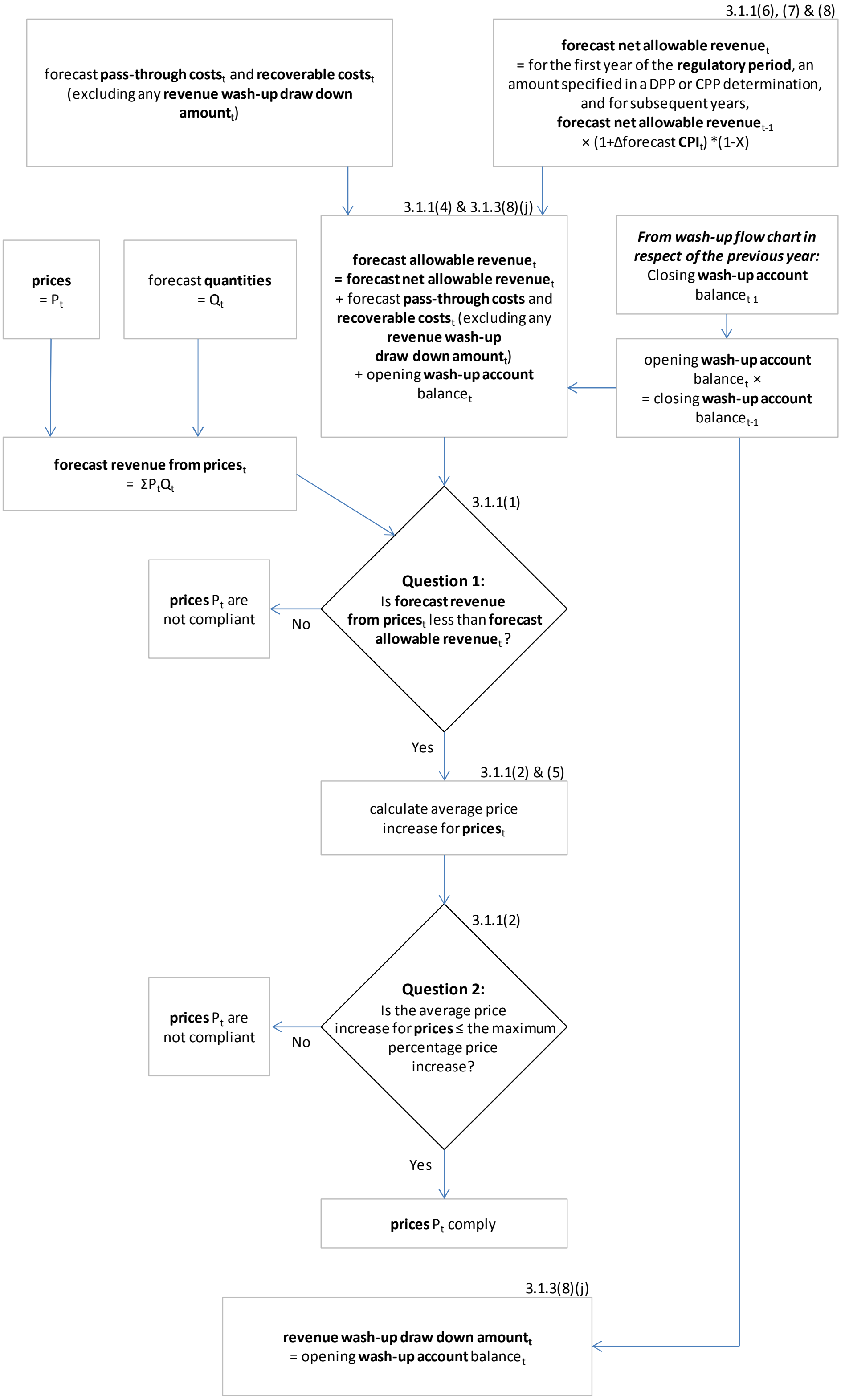
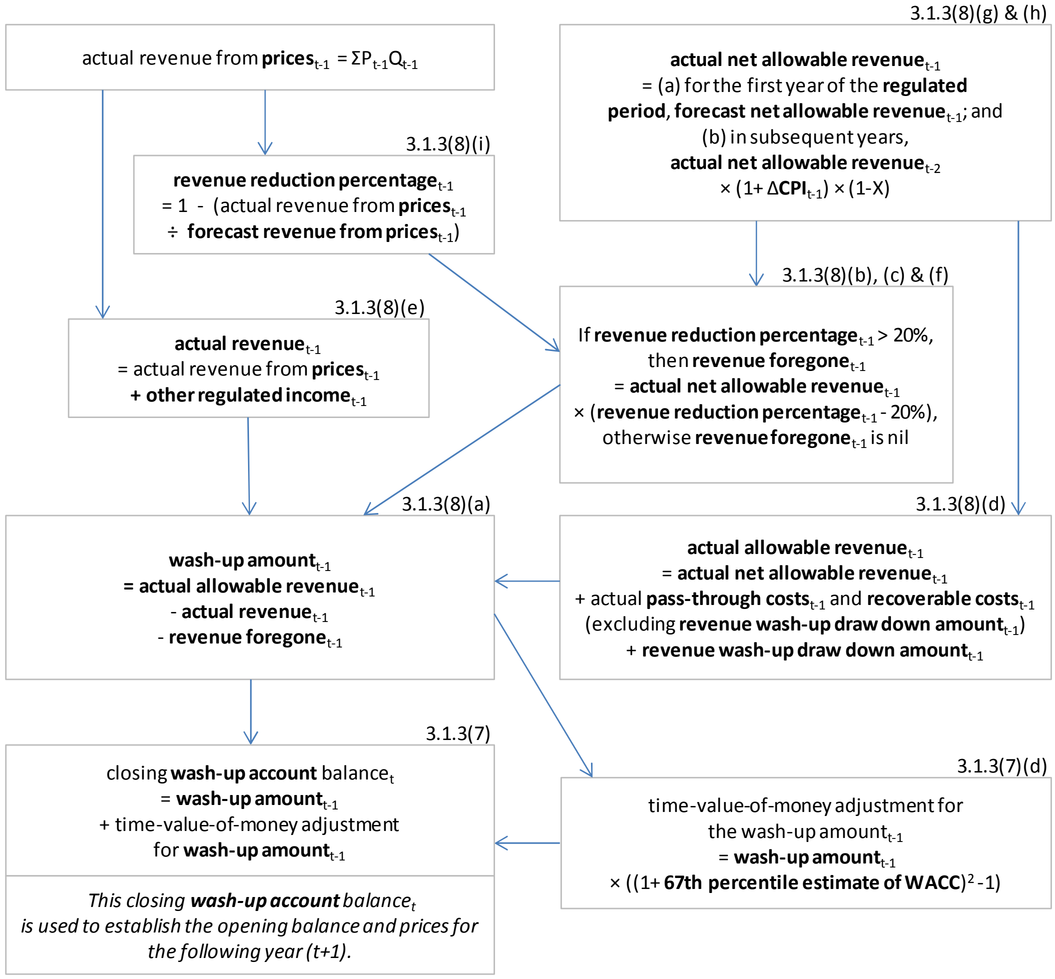


Figure F2

Determining the wash-up amount and the closing balance of the wash-up account for Year t for a GTB



F74 A positive wash-up amount indicates that the actual revenue received (plus any amount of revenue foregone) has been less than the actual allowable revenue. That positive balance would lead to a positive balance in the wash-up account, which would be in favour of the supplier.

F75 For the purpose of calculating the actual allowable revenue and for calculating the closing wash-up account balance, the revenue account draw-down amount has been set to the opening balance of the wash-up account.

F76 The calculation of the closing wash-up account balance in the flow chart above could alternatively be specified as:

opening wash-up account balance

less revenue wash-up account draw-down amount

plus wash-up amount

plus time value of money adjustment for wash-up amount

F77 The first two terms of this calculation cancel each other out, which has allowed the formula in the flow chart to be simplified by deleting these two terms. This simplified approach has been used in the draft determination.

F78 The actual allowable revenue for the first assessment period will include an additional term in the formula stated in the flow chart above. It shall account for any unrecovered pass-through and recoverable costs in the regulatory period ending 30 September 2017 that were not recovered in that regulatory period. The amount of the additional term shall be the amount not recovered plus a time value of money adjustment for one year on that amount. The discount rate for time value of money adjustment shall be 5.38%. This discount rate is discussed at paragraph F58.

F79 The numbers at the upper-right corner of several of the flow chart boxes, eg, 3.1.3(8)(a), refer to the relevant clauses in the GTB input methodology Determination.

Attachment G Data and inputs to the financial model

Purpose

G1 This attachment sets out how we sourced and used the data as input to the financial model, and what data estimations we have made. It discusses the data that we used in the financial model for the draft decision, as well as the data that we will use for the final decision.

G2 This attachment includes discussion of data that is used to inform our projections of some data that is input to the financial model, including opex, capex, CPRG, other regulated income, and disposals data. We have also made some data estimations for financial modelling and supplier forecasting purposes and this will be fully explained. If any improvements can be made to these estimations then we will be open to changes for the final decision.

Overview of data used in the financial model

G3 The data inputs to the financial model falls into four categories:

G3.1 inputs that are not supplier-specific, such as WACC and CPI;

G3.2 data based on supplier-specific information from AMPs of IDs;

G3.3 data based on supplier-specific information from ID Schedules 1 to 10, or in the case of the previous Vector distribution networks, information from section 53ZD requests to disaggregate some of this data between the Vector and First Gas distribution networks; and

G3.4 data we have had to estimate for financial modelling and supplier forecasting purposes.

Non-supplier-specific data modelling

Reflating expenditure forecasts from real to nominal

G4 Under our approach to forecasting expenditure we look at suppliers' own forecasts, which we adjust if insufficient evidence has been provided to justify substantial increases. These forecasts are assessed in real terms. However, the financial model requires these forecasts in nominal terms.

G5 To correct for this we have built an expenditure reflation model, published alongside this paper.[179] Opex forecasts are reflated using a combination of the Labour Cost Index (**LCI**) and the Producer Price Index (**PPI**) in a 60:40 ratio. Capex is reflated using

[179] Commerce Commission “Expenditure reflation model” (10 February 2017) available at http://comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

the PPI only. Both of these indices were obtained on the Statistics New Zealand website.

G6 The ratio selection is in line with the input price component we used for the opex step and trend calculations in the last Gas DPP reset. In the absence of labour expenditure data from New Zealand suppliers, these weights are based on analysis of labour costs by Australian GDBs.[180]

Constant price revenue growth

G7 CPRG forecasts incorporate the growth in both the variable charge component (quantity of gas billed) and fixed charge component (number of ICP connections).

G8 To estimate the variable charge component we use supplier ID information to gain a historical view of the trend in our CPRG model.[181] We also used an independent study from Concept Consulting on behalf of the GIC.[182] A technical review of this study, commissioned by the Commerce Commission, was published alongside our policy paper on 30 August 2016.

Consumer Price Index

G9 We are required to estimate CPI as part of the price-path setting process. We have created a CPI model, published alongside this paper to do this.[183] The inputs to this model are the historical quarterly CPI data from Statistics New Zealand[184] and quarterly CPI forecasts from the Reserve Bank of New Zealand.[185]

Disaggregated data for previous Vector distribution network

G10 The former Vector gas distribution network has been recently split into two networks, one of which has been sold to First Gas and the other retained by Vector.

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180 Meyrick and Associates, The Total Factor Productivity Performance of Victoria's Gas Distribution Industry, Report prepared for Envestra, Multinet and SP AusNet, Denis Lawrence, 2007, available at http://www.economicinsights.com.au/reports/Economic_Insights_Victorian_GDB_TFP_Report_26Mar2012.pdf.

181 Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015) NZCC7, Schedule 8; Electricity Transmission Disclosure Determination 2012 (consolidated on 2015) NZCC8, Schedule 8, available at http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-information-disclosure/.

182 Concept Consulting Group Ltd "Approach to developing distribution network demand projections" (4 July 2016), available at http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/.

183 Commerce Commission "CPI model" (10 February 2017), available at http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/.

184 Stats NZ: Consumers Price Index: September 2016 - corrected tables, available at http://www.stats.govt.nz/browse_for_stats/economic_indicators/CPI_inflation/ConsumersPriceIndex_HOTPSep16qtr/Tables.aspx.

185 Reserve Bank of New Zealand: Monetary Policy Statement for August 2016, available at http://www.rbnz.govt.nz/monetary-policy/monetary-policy-statement/mps-august-2016.

G11 To meet the financial modelling data requirements, we requested and have used historical data from Vector that was disaggregated into data relating to the new Vector Auckland and the First Gas non-Auckland networks.

G12 Some of the data requirements were met through a data request under section 53ZD, and other data will be available through IDs that the parties agreed to provide.

G13 For supplier forecasting we had to create notional historic data for the Vector Auckland and First Gas non-Auckland networks based on the proportion of the asset split and the former Vector distribution historic expenditure. This notional historic data was used in the supplier forecasting process to create a 2016 base year expenditure value for the new Vector and First Gas distribution entities. This set what were considered to be BAU expenditure levels.

Financial modelling of First Gas transmission

G14 For the DPP financial model, the previous MDL and Vector transmission networks have been separately modelled, with the MAR for the pricing year ending 30 September 2018 (the first year of the new DPP period) being calculated for each network. These two MAR values have been added together to make the MAR for the First Gas transmission network as a whole.

G15 This approach is proposed because much of the input data for the financial model will be from historical IDs, and this data is not readily aggregated into a single dataset for the combined network.

G16 A key reason the data is not readily aggregated is that the MDL network data has an ID year-end of 31 December, and the Vector transmission network data has an ID year-end of 30 June. The IMs that must be applied in setting the DPP starting prices require many of the calculations to be performed on an ID year-end basis.

G17 First Gas transmission supplied its 2016 AMP information on a 30 September year-end basis, and also provided us with expenditure forecast information for the former MDL and Vector transmission businesses on the same year-end basis.

G18 The present financial model requires the capex and opex forecast information to be represented on the previous MDL and Vector transmission business year-end bases. This has required us to split the MDL and Vector forecast information from First Gas into calendar year quarters,[186] so we can shift the year-end time references for financial model input.

G19 For example, to represent the former Vector transmission 30 June year-end data for 2018 using the 30 September year-end data provided by First Gas, we removed the

[186] For example Q1 represents the first quarter January 1st to March 31st, Q2 represents the second quarter 1 April to 30 June, Q3 the third quarter 1 July to 30 September and Q4 the fourth quarter from 1 October to 31 December.

Vector transmission Q3 expenditure for 2018 and added the Vector transmission Q3 data for 2017.[187]

G20 Splitting the forecast information into quarters like this assumes that seasonality has little impact on expenditure patterns throughout the year. However we are open to changing this approach if seasonality is an issue and First Gas can provide the MDL and Vector transmission expenditure forecast information on a quarterly rather than yearly basis.

Other regulated income

G21 For the First Gas transmission business, we will not require a forecast of other regulated income because the GTB IMs provide for other regulated income to be accounted for through a wash-up mechanism as part of a revenue cap.

G22 For GDBs, the financial model requires as data input a forecast of other regulated income for each BBAR year.

G23 A BBAR year is a 12-month period that coincides with an ID year for the supplier; and such some or all of the BBAR year is within the regulatory period. The year-end of these BBAR years varies between suppliers.

G24 The BBAR year-ends for data inputs to the financial model have been kept the same as the year-ends for ID for each supplier. For the First Gas networks, we have kept the year-ends that applied to the previous owner of each of the three networks that First Gas has acquired.

G25 Our draft view is that we could forecast these values by establishing a forecast for the first building blocks year, and to forecast this value as constant in real terms for the following four years. This approach was taken in the previous Gas DPP reset, and the most recent EDB DPP reset.

G26 The first year value will be based on the average of four previous years. We noted in our policy paper that Vector's IDs relating to its gas distribution business may have disclosed the recovery of bad debts from a previous year as other regulated income. Vector has confirmed that this income was received from the liquidator of a retailer. It was effectively revenue from prices, but with a delayed cash flow because of the retailer liquidation.

G27 We consider that this revenue to the former Vector gas distribution network should not be treated as other regulated income for setting starting prices. Further we have projected a nil value of other regulated income for the First Gas and present Vector gas distribution networks.

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[187] Commerce Commission "Expenditure model" (10 February 2017), available at http://comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/.

Disposals

G28 The disposals data required by the financial model is, for each BBAR year, the projection of the RAB value of disposals and the projection of the gain or loss on disposals. This information will be projected constant in real terms.

G29 We have projected the RAB of disposals and the gain/(loss) on disposal using a similar methodology to that used for other regulated income, as discussed in paragraph G25. Values have been on an historical average and kept constant in real terms for the regulatory period.

G30 Table G1 sets out the materiality of disposals data for the former Vector gas distribution network. The values are not particularly material, relative to total regulatory income.

Table G1 Gain/(loss) on disposal and RAB of disposals, former Vector gas distribution network, compared to total regulatory income ($'000s)

Year ending	2013	2014	2015
Gain/(loss) on disposals	($166)	($50)	($116)
RAB of disposed assets	$190	$50	$143
Total regulatory income	$86,342	$75,313	$75,545

Data availability for the draft and final decisions

G31 The draft decision includes a version of the financial model with some capex and opex forecast data inputs requiring to be updated before a final version is prepared. Some of these data inputs were not available in their final form so the draft decision modelling outputs will be subject to change.

G32 As noted in the policy paper, we published an early exposure draft of the financial model on 1 July 2016 and the inputs sheet in that model indicated the data inputs we envisage would be required.[188]

G33 WACC information is required by the IMs to be determined as at 1 March 2017, which is after we intend to publish the draft decision. An update to the financial model value of WACC will be required between the draft and final decisions.

G34 We have used all available projections of opex and capex from the suppliers' AMPs in our determination of opex and capex inputs to the financial model for the draft

[188] Financial model (available on our at http://www.comcom.govt.nz/dmsdocument/14421) published with our paper "Implementing matters arising from proposed input methodologies changes".

decision. We received AMPs from GasNet in June 2016; Vector in August 2016; and from both Powerco and First Gas in September 2016.

G35 Table G2 sets out the availability of data from ID Schedules 1 to 10.

Table G2 Schedule 1-10 ID data availability for the draft and final decisions for the 2017 GPB DPP reset

Supplier	ID year-end	Draft decision ID data used[189]	Final decision ID data to be used
GasNet	30 Jun	2015 ID data – 21 Dec 2015[190]	2016 ID data – 21 Dec 2016
Vector distribution	30 Jun	2015 disaggregated ID data – 31 Aug 2016[191]	2016 disaggregated ID data – 20 Dec 2016
Powerco	30 Sep	2015 ID data – 17 Mar 2016	2016 ID data – Feb 2017[192]
First Gas distribution	30 Jun	2015 disaggregated ID data – 31 Aug 2016[193]	2016 disaggregated ID data – 19 Dec 2016
First Gas (ex MDL) transmission	31 Dec	2015 ID data – 30 Jun 2016[194]	2015 ID data – 30 Jun 2016
First Gas (ex-Vector) transmission	30 Jun	2015 ID data – 23 Dec 2015[195]	2016 ID data – 19 Dec 2016

[189] The financial model contains updates of all available ID data that was received up to 23 December 2016 except for forecast capex and opex.

[190] Due to timing of the receipt of the 2016 ID information and publication timing of the draft decision, we used the 2015 ID data for the draft decision.

[191] Vector provided disaggregated Auckland and non-Auckland network ID data for the 2015 ID year on 31 August 2016. Vector also provided disaggregated Auckland network ID data for the 2016 ID year on 20 December 2016. Due to timing of the receipt of the 2016 ID data and publication timing of the draft decision, we used the 2015 ID data for the draft decision.

[192] Powerco will provide 2016 ID data early in February 2017. The final decision process will not be able to take into account ID data provided on 31 March 2017.

[193] Provided in conjunction with Vector disaggregated Auckland network ID data on 31 August 2016, for the 2015 ID year. Due to timing of the receipt of the 2016 ID data and publication timing of the draft decision, we used the 2015 ID data for the draft decision.

[194] We have used the MDL Transmission 2015 ID data for the draft decision and will also do so for the final decision. The 2016 ID data for the MDL part of First Gas transmission will not be available until 30 June 2017 which is after the final decision publication date.

[195] Due to timing of the receipt of the 2016 ID data and publication timing of the draft decision, we used the 2015 ID data for the draft decision.

Attachment H Step and trend model of operating expenditure

Purpose

H1 The purpose of this attachment is to describe our step and trend model for opex, which could be used as an alternative fall-back.

Our approach to step and trend modelling

H2 The step and trend model is fundamentally the same as that used in the 2013 Gas DPP reset. This document highlights all the inputs used in the approach, some of which have been modified from the 2013 Gas DPP reset.

H3 Step and trend analysis starts from a single base year or an average of multiple base years, which is then projected forward on the basis of forecast changes in the main drivers of opex. We have adopted this approach because opex in the gas pipeline industry is typically recurring, in that it is likely to be repeated regularly, and influenced by certain known and predictable factors.

H4 The general approach used in our step and trend model is shown below.

Formula for calculating opex

$$\text{Opex}_t = \text{opex}_{t-1} * (1 + \Delta \text{ due to network scale effects} - \Delta \text{ partial productivity for opex} + \Delta \text{ input prices})$$

H5 The variables represented in the formula are:

H5.1 network scale—all other things being equal, change in the scale of the network would be expected to affect opex because the volume of service provided will change.

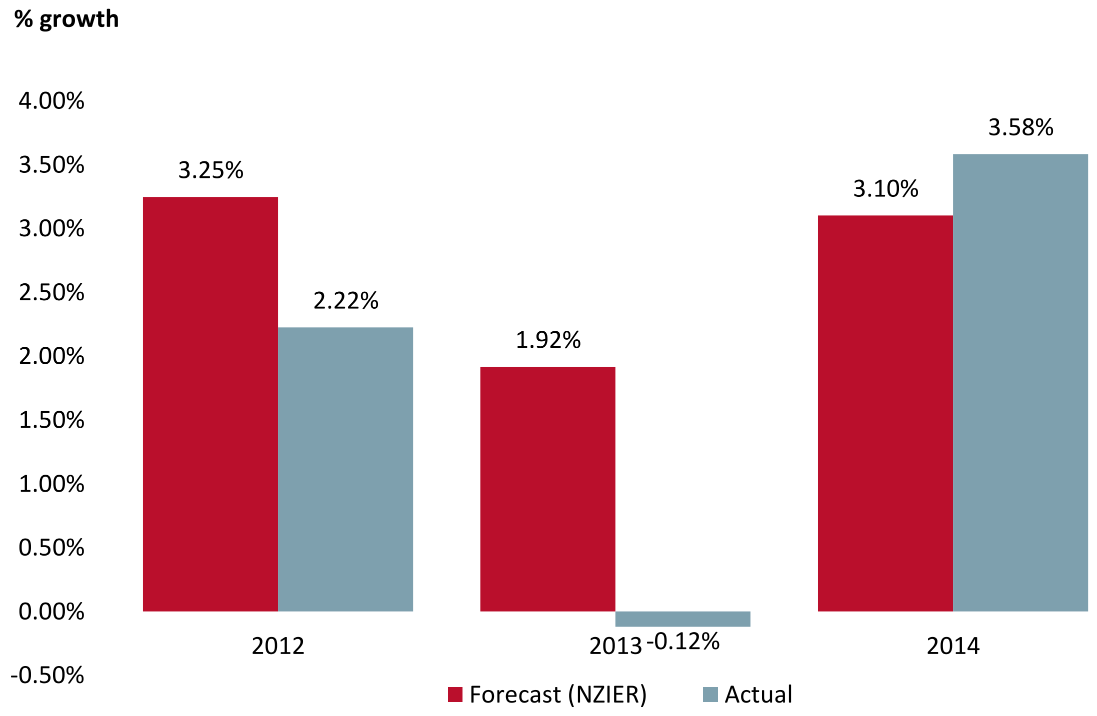
H5.2 partial productivity—improvements in opex partial productivity will reduce the amount of opex needed to provide a given level of service, eg, due to changes in technology.

H5.3 input prices—changes in input prices will affect the cost of providing a given level of service over time.

Appropriateness of approach

H6 We have examined the extent to which our forecasts of opex for the current regulatory period have diverged from the actual level of opex reported under ID. This indicates that the step and trend approach for modelling opex remains appropriate. The major driver of variance between actuals and forecasted opex in the current regulatory period is input prices, where forecasts of movements in the PPI have generally exceeded actual movements, as evident in Figure H1 below.

Figure H1 Producers Price Index growth



Modelling inputs

H7 There are eight inputs into the step and trend methodology:

- H7.1 PPI
- H7.2 LCI
- H7.3 input price weighting
- H7.4 multiplicative or additive formula
- H7.5 base year
- H7.6 scale elasticity
- H7.7 partial productivity
- H7.8 out of trend factors

H8 Each of these inputs for our modelling is described below.

Producers Price Index

H9 We have considered whether to use sector-specific PPI forecasts. However, our preference is to continue using the All Industries PPI (inputs) forecast. We used an All Industries PPI (inputs) index forecast. Statistics New Zealand supplied historic PPI data, with NZIER supplying four years of quarterly forecast PPI.

H10 To forecast PPI to the end of the DPP period, we extended the NZIER forecast series using a CPI forecast provided by the Reserve Bank of New Zealand, extended according to the input methodology guidelines.[196, 197]

H11 An alternative to using the All Industry PPI would have been to use a sectoral index such as the electricity and gas PPI. However, this subindex is heavily weighted (75%) towards the electricity generation sector, with the gas sector comprising 9%. Also, subindices naturally have more fluctuations than more robust all industry indices. This variance would have added extra complexity to forecasting, increasing the chance of a large forecast error.

Labour Cost Index

H12 We used a forecast of the All Industries LCI forecast. Statistics New Zealand supplied historic LCI data, with NZIER supplying five years of forecast LCI. Statistics NZ also produces historic LCI data on a sector and subsector basis, but we did not use this information.

H13 The most relevant LCI subindex for gas is the Electricity, Gas and Waste Water (EGWW) subindex. LCI is forecast in a different way to the PPI with fewer 'layers' in the forecasting approach. Because of this it is not possible to identify the weight given to the gas sector within this index in the same way as the PPI. Without supporting data we assume the 9% gas weighting in the electricity and gas PPI index is a good guide for the gas weighting in the EGWW LCI subsector.

H14 Using an all industries forecast is appropriate as it is likely to provide a good proxy for sector-specific indices, which can be complex to predict individually. Subindices naturally have more fluctuations than the more robust all industry indices.

H15 NZIER forecast LCI five years into the future. To extend this forecast to the end of the DPP period we extend the NZIER forecast series using a CPI forecast provided by the RBNZ extended according to the input methodology guidelines.[198] The CPI forecasts are then adjusted with a premium of -0.17%, in line with advice from NZIER.[199]

Input price weighting

H16 We derived an index for input prices by applying a 60% weighting to the forecasted LCI and a 40% weighting to the forecasted PPI. In the absence of labour expenditure data from New Zealand suppliers, these weights were based on analysis of labour

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196 Gas Transmission Services Input Methodologies determination 2012 [2012] NZCC 28.

197 Email from Shamubeel Eaqub (Principal Economist, NZIER) to the Commerce Commission on extending NZIER forecast horizons (1 October 2010).

198 CPI forecast extended beyond IM guidance by one year.

199 Email from Shamubeel Eaqub (Principal Economist, NZIER) to the Commerce Commission on extending NZIER forecast horizons (1 October 2010).

costs by Australian GDBs.[200] This is in line with the step and trend modelling used for the previous gas pipeline DPP reset.

Multiplicative or additive formula

H17 We have aligned the step and trend modelling for the Gas DPP draft decision with the EDB DPP reset by using a multiplicative formula to calculate opex rather than an additive formula.[201] Intuitively, any scale-related changes in opex will also be impacted by any change in input prices and productivity. Using a multiplicative formula would account for this.

H18 The multiplicative formula is:

$$\text{Opex}_t = \text{opex}_{t-1} * (1 + \Delta \text{ due to network scale effects}) * (1 - \Delta \text{ partial productivity for opex}) * (1 + \Delta \text{ input prices})$$

Base year

H19 We have used an average of the three years of most recently available data as the base year. This approach smooths out any unusual single-year increases or decreases in opex. Multi-year bases also reduce incentives in future resets to alter the profile of opex to maximise expectations of opex in future regulatory periods.

Scale elasticity

H20 In the previous Gas DPP, Castalia (on behalf of Vector) undertook an analysis of Australian and New Zealand gas distribution data from 2010 to estimate the relationship between network scale (where network scale was based on network length and customer numbers) and opex. This analysis provided an elasticity of 0.98 which indicates that a 10% increase in network scale is associated with a 9.8% increase in opex.[202]

H21 For the GDBs this elasticity was then applied across network length growth (50%) and customer number growth (50%). The network scale elasticity for gas transmission services was set to zero.[203]

H22 We have used a similar approach to forecasting scale elasticity as we did in the previous DPP process. Using the real opex data in New Zealand dollars, we have

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[200] Meyrick and Associates "The Total Factor Productivity Performance of Victoria's Gas Distribution Industry, Report prepared for Envestra, Multinet and SP AusNet" Denis Lawrence, (2007).

[201] Commerce Commission "Low cost forecasting approaches final decision EDB DPP" (November 2014), paras 3.5 and 28.

[202] Castalia "Vector submission on revised draft decision on gas initial DPP Appendix 2" (7 December 2012). The Castalia analysis followed the approach the Commission had proposed in the draft decision (October 2012), but applied the analysis to Australian and New Zealand GDB data rather than the UK data to which the Commission referred in the draft.

[203] Commerce Commission "Reasons for setting default price quality paths for suppliers of gas pipeline services" (28 February 2013), para C20.

replicated Castalia's analysis for 2010 and 2012. The 2010 coefficient did not change significantly using real data instead of nominal data.[204, 205, 206]

H23 We have combined the two years and used a pooled approach to estimate the opex scale elasticity. The pooled opex scale elasticity is 0.951, compared with 0.9758 in the previous DPP.

H24 For GDBs we applied this updated elasticity across network length growth (50%) and customer number growth (50%). We calculated these growth rates as the trended natural log of three years' worth of data.

H25 We have considered distribution and transmission businesses separately in considering how the scale measures should be applied. We consider that scale elasticity for transmission businesses should again be set to zero.

Partial productivity

H26 We have not commissioned a partial productivity study as part of the DPP reset. Given the purpose of the step and trend approach for the 2017 reset, and that we are intending to use and scrutinise supplier forecasts to determine our opex forecasts, we do not consider that commissioning a productivity study is required or appropriate at this time.

H27 We have assumed a 0% change in operating efficiency as was done for the previous gas pipeline DPP reset. This assumption was informed by analysis provided by Economic Insights on historical opex partial productivity changes for New Zealand and overseas suppliers of gas pipeline services. We received submissions from MDL and Powerco supporting a factor of 0% for opex partial productivity.[207]

Out of trend factors

H28 We have not identified any out of trend factors that need to be applied to the 2017 DPP.

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[204] Castalia "Review of the Draft Decision on the Revised Initial Default Price-Quality Paths for Gas Pipeline Services" (December 2012). Available at http://www.comcom.govt.nz/dmsdocument/9718

[205] Economic Insights "Relative Opex Efficiency and Forecast Opex Productivity Growth of Jemena Gas Networks" (25 March 2015), page 43.

[206] We have contacted the Australian Energy Regulator (AER) to see whether there is more recent data available. The AER informed us that it collects information from the Australian gas distributors on an annual basis, although the information is not currently published.

[207] Commerce Commission "Reasons for setting default price-quality paths for suppliers of gas pipeline services" (28 February 2013).