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Default price-quality paths for gas pipeline businesses from 1 October 2017

Final Reasons Paper

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Associated documents

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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
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10 February 2017	ISBN 978-1-869455-60-6	Gas Transmission Services Default Price-Quality Path Draft Determination 2017
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13 April 2017	ISBN 978-1-869455-72-9	Gas Transmission Services Default Price-Quality Path Technical Consultation Draft Determination 2017
13 April 2017	ISBN 978-1-869455-73-6	Gas Distribution Services Default Price-Quality Path Technical Consultation Draft Determination 2017
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31 May 2017	ISSN 1778-2560	[2017] NZCC 15 Gas Distribution Services Default Price-Quality Path Determination 2017

Commerce Commission
Wellington, New Zealand

Contents

Executive summary

Purpose of this paper

X1 This paper sets out and explains our decisions on the default price-quality paths (**DPP**) for gas pipeline businesses (**GPBs**) from 1 October 2017. This paper gives the reasons for our decisions on:

X1.1 price-paths (starting prices and rates of change);

X1.2 quality standards; and

X1.3 how GPBs must demonstrate compliance with the DPP.

Decisions on setting the price-path

X2 Our decision is to reset prices on the basis of current and projected profitability. The starting prices we have set for each supplier are listed in Table X1. We also estimate the impact of our decision by comparing starting prices with the starting prices we would have 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	$4m	-12%
Powerco	$47m	-9%
Vector	$44m	-21%
First Gas distribution	$22m	-20%
First Gas transmission	$122m	-10%
Industry total	$239m	-13%

1 Maximum allowable revenue (**MAR**) in the first year of the regulatory period. For Gas Transmission Businesses (**GTB**s), this is expressed as forecast net allowable revenue (**FNAR**).

2 This is the difference between Allowable Notional Revenue (**ANR**) or Forecast Allowable revenue (**FAR**) (for GTBs) in the first year of the 2017-2022 regulatory period, based on our 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.

X3 Our 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 (**GDB**s), we have also relied on 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 it is necessary to reset prices on the basis of current and projected profitability.

X4 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 current and projected profitability[3]	Forecast revenue from a roll-over[4]	Forecast over-recovery if prices rolled over[5]	% difference
GasNet	$19m	$22m	$3m	-12%
Powerco	$216m	$236m	$20m	-8%
Vector	$200m	$254m	$53m	-21%
First Gas distribution	$101m	$126m	$25m	-20%
First Gas transmission	$559m	$622m	$62m	-10%
Industry total	$1,096m	$1,259m	$163m	-13%

X5 We must also set a rate of change, relative to the consumer price index (**CPI**), by which prices increase over the regulatory period (referred to as the 'X-factor'). Based on our analysis of productivity in the sector, we have set the X-factor at 0%.

Impact of price changes on consumer bills

X6 On average at a North Island-wide level, we estimate that an average consumer's gas bill will be approximately 6% lower than it would have been had we rolled over current prices. This figure is indicative only, and assumes any reductions in prices are passed through to consumers. Actual bills will vary based on region, retailer, plans, and usage patterns.

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[3] Estimate of the present value of ANR (for GDBs) or FAR (for GTBs) across the regulatory period, based on the starting prices we have set.

[4] Estimate of the present value of ANR or FAR calculated by rolling current prices forward by forecast CPI, and for GDBs by forecast changes in demand.

[5] Over the regulatory period, in present value terms.

Factors influencing changes in starting prices

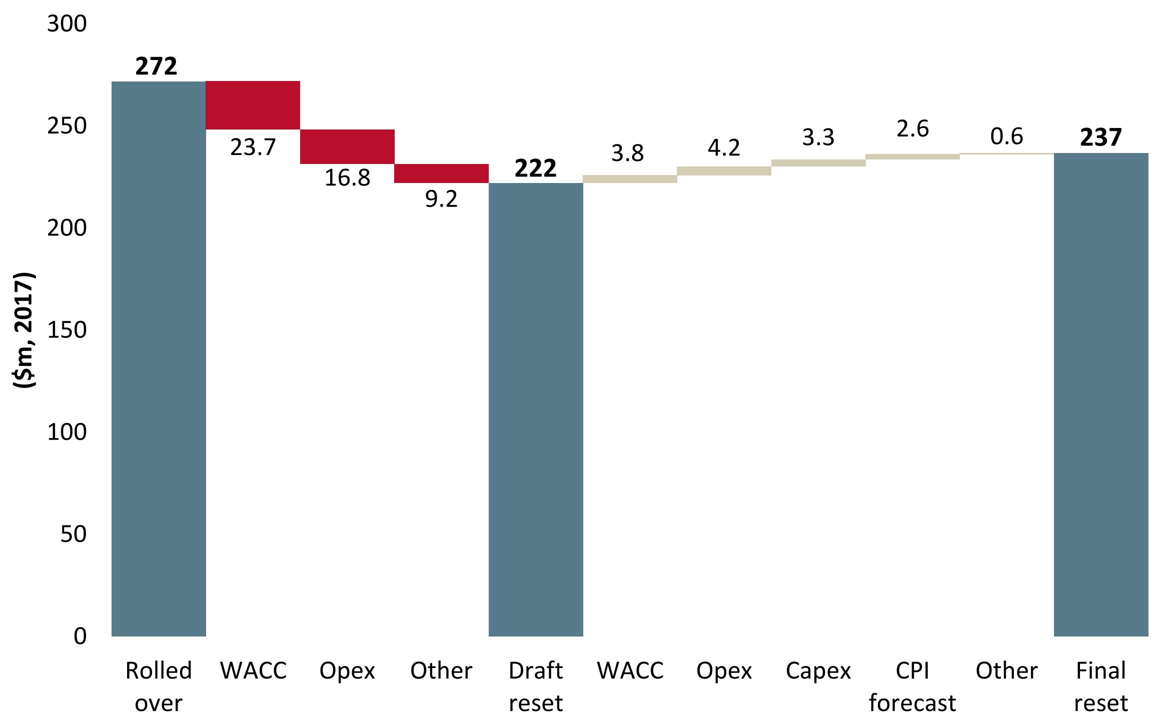
X7 Two major factors help explain these changes in starting prices:

X7.1 changes to our estimate of the weighted average cost of capital (**WACC**) used to determine GPBs' return on capital;[6] and

X7.2 changes in operating expenditure (**opex**) forecasts, relative to the forecasts we set in 2013.[7]

X8 The left-hand side of Figure X1 shows the main changes between rolled over prices and the prices we proposed in our draft decision. The right-hand side shows the main changes we have made since our draft decision, which are discussed in more detail in the next section.

Figure X1 Changes compared to a roll-over and from draft to final[8]



Reduction in WACC

X9 The WACC rate we have used to set the price-path is 6.41%, shown on the far right of Figure X2 below. The WACC used to set the price-path in 2013 was 7.44%, shown on the far left.

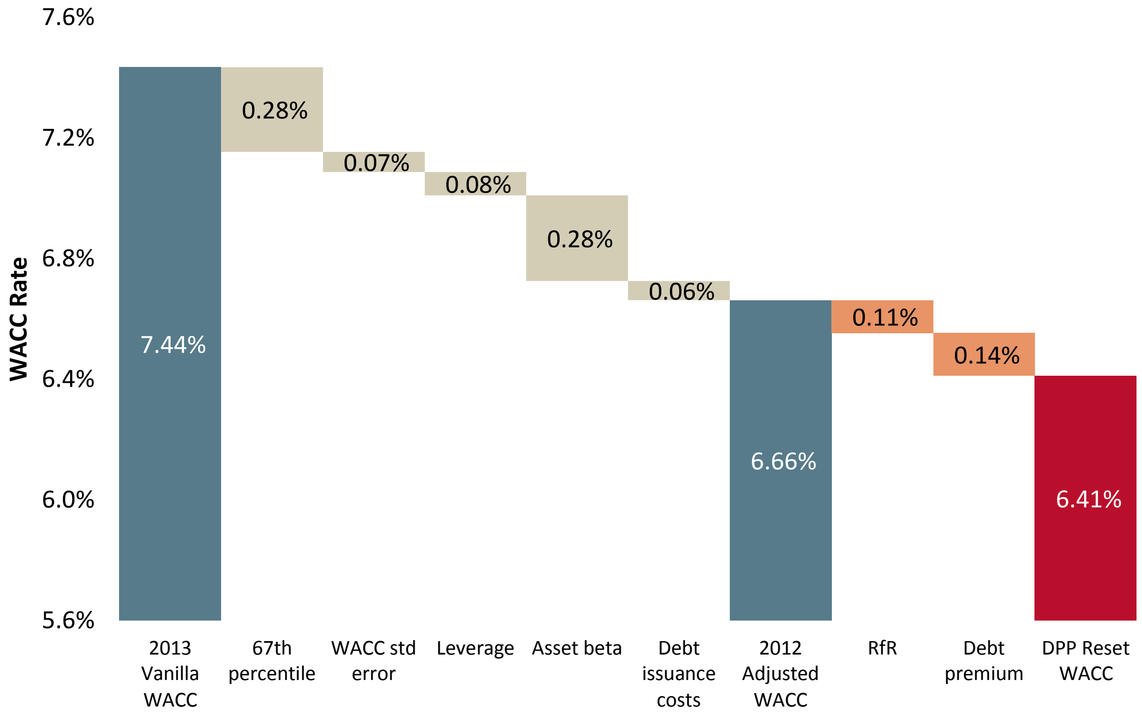
6 The price-path is set using the 'vanilla' WACC, and unless specified all references to WACC in this paper refer to the vanilla WACC.

7 Other factors which have influenced the starting price change are CPRG, CPI, and suppliers' RABs.

8 ANR (or FAR) in the first year of the regulatory period.

X10 This change in WACC is due to both changes to the input methodologies (**IMs**), shown on the left in tan, and changes in the inputs we use to determine WACC parameters (the risk-free rate and the debt premium), shown on the right in orange. The input parameters have changed since our draft decision.

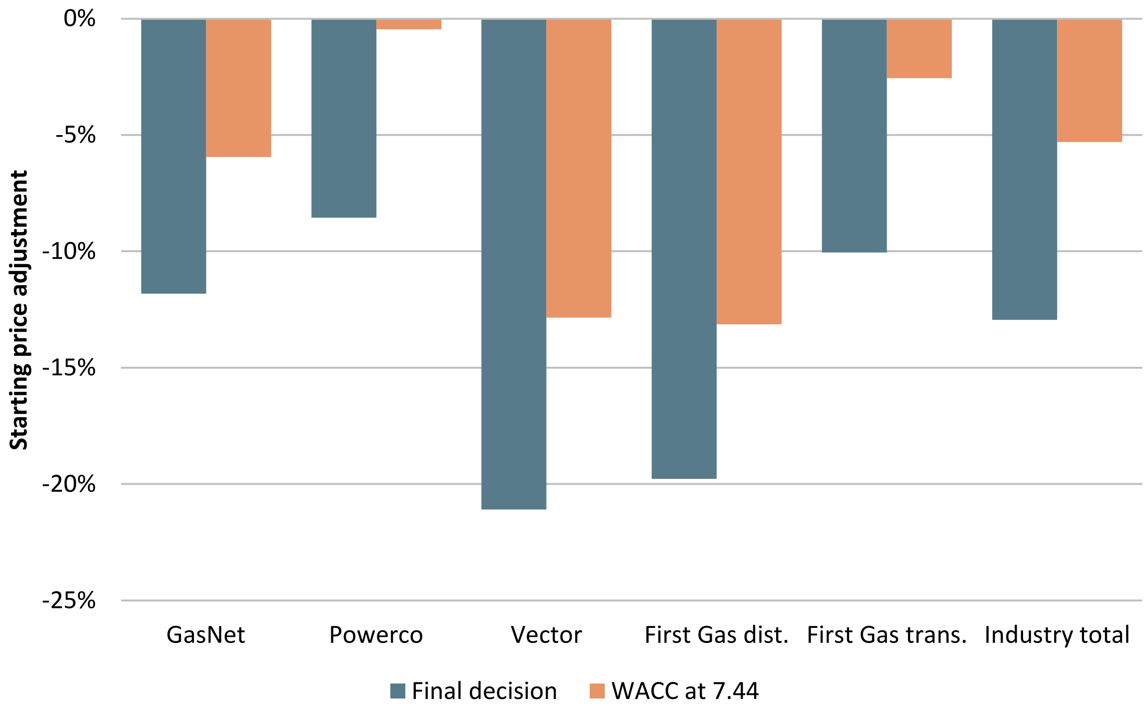
Figure X2 Cumulative effect of changes to the Vanilla WACC[9]



X11 The impact of these WACC changes on starting prices is shown in Figure X3. The chart compares the actual change in starting prices to a scenario where the WACC (and cost of debt) are unchanged from our 2013 decision.

[9] The chart is on a non-zero scale.

Figure X3 Impact of reset on price/revenue cap – WACC scenarios[10]



Changes in opex forecasts

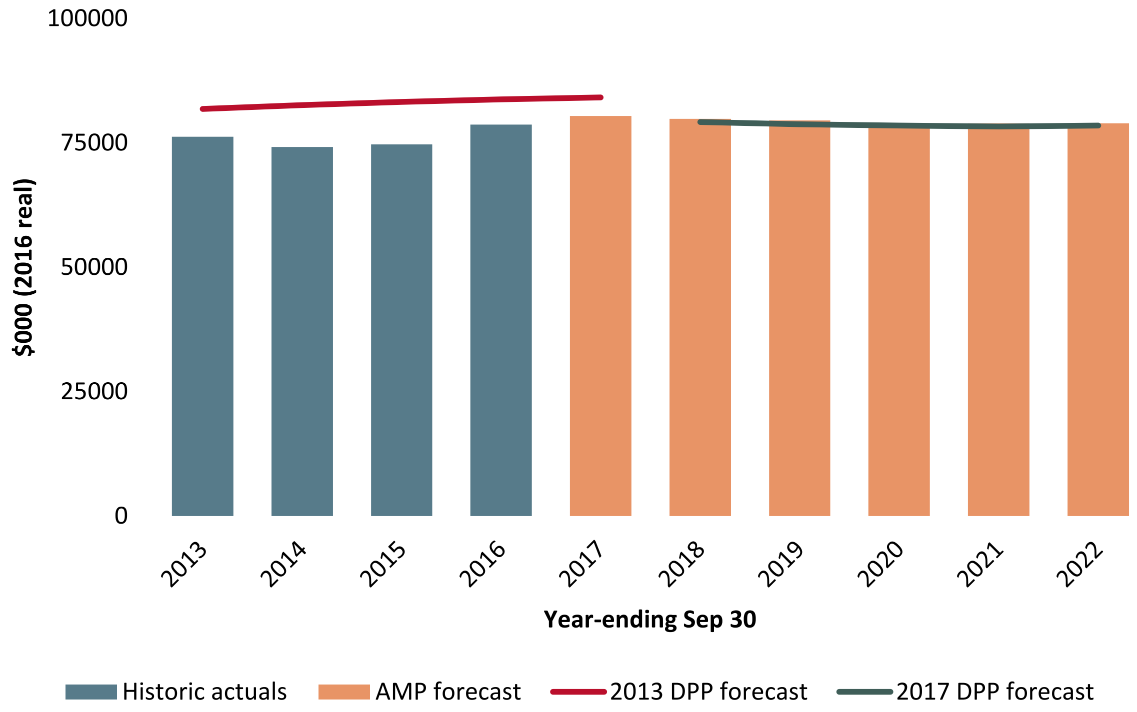
X12 Our opex forecasts for the 2017 to 2022 DPP are lower on average (in constant price terms) than our forecasts for the 2013 to 2017 DPP.

X13 This is partly because actual historic opex (which we use as the starting point for our assessment of supplier forecasts) was lower than our 2013 forecasts. In some cases it is also because our opex forecasts are lower than suppliers' forecasts in their Asset Management Plans (**AMPs**).

X14 Figure X4 below presents our industry total opex forecasts (from the 2013 DPP reset and the 2017 DPP reset), as well as suppliers' AMP forecasts and historic actual expenditure.

[10] The blue bars show the difference between the reset and roll-over starting price scenarios, as in Table X1. The orange bars show this same comparison, but with the WACC rate used in determining the 'reset' scenario at 7.44% as opposed to 6.41%.

Figure X4 Comparison of industry total opex forecasts[11]



Key changes from our draft decision

X15 We have made three kinds of key changes since our draft decision which impact starting prices:

X15.1 changes to expenditure forecasting decisions;

X15.2 changes based on updated input data; and

X15.3 changes to the WACC and cost of debt.

X16 We have also corrected for two errors identified in our draft decision;

X16.1 we have corrected the base year used to inflate forecasts from 2016 real prices to nominal prices; and

X16.2 we have now included the cost of financing works during construction in our capex forecasts for all suppliers.

X17 Additionally, we have made changes to quality standards and compliance provisions (which do not impact starting prices).

[11] Values are in $2016, adjusted from supplier-specific year ends to a common September year end. Note we have changed how we accounted for inflation in presenting our 2013 forecasts to better represent the impact of opex on starting prices.

Changes to expenditure decisions

X18 We have made the following key changes to our expenditure forecast decisions based on submissions and additional information provided by suppliers:

X18.1 accepting Vector's non-network opex forecasts, and changing the way we account for losses in economies of scale;

X18.2 accepting First Gas' distribution system growth capex forecasts;

X18.3 accepting First Gas' updated distribution consumer connection capex forecasts;

X18.4 accepting First Gas' transmission routine and corrective maintenance opex forecasts; and

X18.5 accepting First Gas' transmission asset replacement and renewal capex (except for forecast expenditure for the White Cliffs realignment project).

First Gas' purchase of GasNet's Papamoa assets

X19 We have not changed our draft decision not to apply clause 2.2.11(1)(e) of the IMs (the 'RAB limitation'), as we consider that this clause does not apply to this asset purchase, since the assets had not yet been used to provide regulated services at the time of purchase.

X20 We consider that the assets must be valued based on GAAP under the general rule in clause 2.2.11(1). The net result will be that the value of these assets up to the point of commissioning, excluding any goodwill which is valued at nil in the IMs, will eventually enter First Gas regulatory asset base (**RAB**) when the Bay of Plenty gas distribution assets are commissioned.

X21 This decision is discussed in more detail in Chapter 5.

Changes to input data

X22 We have also updated the data used in our modelling based on the latest Information Disclosure (**ID**) data from suppliers. These updates affect:

X22.1 the 'fall-back' expenditure levels used for forecasts we have not accepted;

X22.2 CPRG forecasts for GDBs; and

X22.3 initial conditions data for Powerco.[12]

X23 We have also updated the CPI forecasts we use.

Changes to the WACC and cost of debt

X24 The WACC estimate we use to determine starting prices has increased to 6.41% (compared to 6.21% in our draft decision). The cost of debt has also increased to 4.76% (compared to 4.54% in our draft decision).

Revision of the WACC determination

X25 We note that the WACC estimate has been revised since it was first published. This revision was made to bring the WACC determination into compliance with the cost of capital IMs.[13]

X26 The impact of this revision was a decrease in WACC from 6.43% to 6.41%. The resulting industry-wide present value change in revenue over the regulatory period is approximately -$1.2 million.

Changes to quality standards and compliance provisions

X27 We have extended the reporting period following major interruptions to 60 days from the end of the critical contingency, instead of 50 days from the interruption.

X28 We have removed the proposed 10% limit on the increase in average prices for gas transmission businesses (**GTB**s).

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[12] This data is the 'base year' information used in the financial model, including RAB values, depreciation, and tax values.

[13] Please see Commerce Commission "Notice of revision of cost of capital determination [2017] NZCC 5" (24 May 2017).

Decisions on forecasting expenditure

How we have approached forecasting expenditure

X29 We have set opex and capital expenditure (**capex**) forecasts based on our assessment of suppliers' forecasts in their AMPs.

X30 We sought 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.

X31 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.

X32 To manage these limitations, we have:

X32.1 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;

X32.2 engaged consultants (Strata) to provide advice on the extent to which GPB's forecast expenditure is justified in its AMP, where the GPB's expenditure forecasts were substantially above historic levels; and

X32.3 sought additional information from GPBs where their AMPs did not sufficiently justify increases in expenditure.

X33 Where we were not able to satisfy ourselves, within the limits of a low-cost scrutiny framework, that a supplier's forecasts represented prudent and efficient expenditure necessary to meet service standards, we replaced its forecasts with 'fall-back' forecasts based on its historic costs.

X34 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.

Capex and opex forecasts

X35 We have accepted some supplier forecasts, but in other cases we have replaced their expenditure forecasts with the fall-back forecasts. The resulting forecasts are set out in Table X3.

Table X3 Expenditure forecasts over the regulatory period[14]

Supplier	Opex	Capex
GasNet	$8m	$4m
Powerco	$82m	$67m
Vector	$56m	$86m
First Gas distribution	$35m	$50m
First Gas transmission	$212m	$139m
Industry total	$393m	$345m

X36 Table X4 compares our forecasts to supplier's AMP forecasts. The difference in GasNet's capex is due to asset replacement and renewal capex being forecast at the fall-back. The differences in Vector's opex and capex are due to reductions resulting from losses in economies of scale. The difference in First Gas' transmission capex is due to the exclusion of the White Cliffs project.

Table X4 Acceptance rates of supplier forecasts[15]

Supplier	Opex	Capex
GasNet	100%	90%
Powerco	100%	100%
Vector	96%	99%
First Gas distribution	100%	100%[16]
First Gas transmission	99%	82%
Industry total	99%	92%

[14] Total over the 1 October 2017 to 30 September 2022 period, in 2016 ID year-end constant prices.
[15] Comparison made over the 1 October 2017 to 30 September 2022 period, in 2016 ID year-end constant prices.
[16] This is compared to First Gas' forecasts as updated for consumer connections in their submission on our draft decision.

Decisions on forecasting CPRG

X37 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.

X38 We do not need to forecast CPRG for GTBs, as they are subject to a pure revenue cap, which is independent of changes in demand.

X39 As signalled in our draft decision, our approach to forecasting CPRG is fundamentally the same as the approach we used in 2013. Updates to the approach include:

X39.1 taking account of more recent information about how suppliers price

X39.2 forecasting demand growth at a regional level; and

X39.3 changes to account for changes in industry ownership structures.[17]

X40 We have also updated our CPRG forecasts based on 2016 supplier ID data, which was not available in time for the draft.

X41 Our forecasts of CPRG are set out in Table X5. CPRG forecasts are discussed in detail in Chapter 6.

Table X5 Forecast CPRG for GDBs[18]

Supplier	CPRG forecast
GasNet	-0.46%
Powerco	0.41%
Vector	2.01%
First Gas distribution	0.96%

[17] 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.

[18] Figures presented here are for 2017. Year-by-year forecasts are available in Chapter 6.

Proposed standards for quality of service

X42 We must also set standards for the quality of service that GPBs must meet. We have set two quality standards:

X42.1 a response time to emergencies (**RTE**) standard for both GDBs and GTBs; and

X42.2 a major interruptions standard for GTBs.

X43 The RTE standard is largely the same as the standard we set in the 2013 DPP, with two changes:

X43.1 we have extended the time a GPB has to request an exemption from the 180 minute RTE standard from 30 working days to 45 working days;

X43.2 a change to how the standard is drafted to improve clarity.

X44 The major interruptions standard is a new feature in the 2017 DPP, and applies only to GTBs. It incorporates:

X44.1 a definition of major interruptions, linked to the declaration of Critical Contingencies that lead to curtailments; and

X44.2 a reporting obligation following any interruption that meets this definition.

X45 Quality standards are discussed in detail in Chapter 7.

Demonstrating compliance with the price-quality path

X46 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:

X46.1 implementing the new 'pure revenue cap' form of control for GTBs;

X46.2 improving how GDBs must demonstrate compliance with the price-path following a restructure of prices; and

X46.3 how GDBs must treat certain kinds of transactions.

X47 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 IM review

X48 In December 2016, we completed our statutory review of the IMs that apply to GPBs. Our decisions on the DPP are based on these new, amended IMs.

X49 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, are included in the GTB determination, and are discussed in Attachment F.

X50 Changes to how we determine the WACC (in particular the WACC percentile and the debt premium) have a significant impact on the price-paths we have set.[19]

X51 Other IMs changes are listed, along with their impacts on the DPP, in Attachment B.

[19] [2014] NZCC 38 Electricity Lines Services and Gas Pipeline Services IM Determination Amendment WACC percentile for ID regulation 2014 – 12 Dec 2014.

Chapter 1 Introduction

Purpose of this paper

1.1 This paper sets out and explains the default price-quality paths (**DPP**) for gas transmission businesses (**GTBs**) and gas distribution businesses (**GDBs**) that will apply from 1 October 2017.[20]

1.2 This paper informs stakeholders about:

1.2.1 our decisions on setting price-paths, quality standards, and compliance reporting requirements;

1.2.2 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;

1.2.3 key changes we have made for our final decision in response to submissions and updated information;

1.2.4 how we have implemented applicable decisions from the input methodologies (**IM**) review;[21] and

1.2.5 the process we have followed.

Structure of this paper

1.3 Table 1.1 sets out and briefly describes each chapter and attachment in this paper.

[20] Even though there is only currently one GTB (First Gas), we refer to 'GTBs' in plural for consistency with the term 'GDBs'. The term 'GPBs' refers to both gas distribution businesses (GDBs) and gas transmission businesses (GTBs). We also use 'suppliers' to refer to GPBs.

[21] 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, and the process for the reset.
Chapter 2	Regulation of price and quality	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 forecasts of supplier expenditure and our consideration of additional expenditure-related adjustments to the DPPs.
Chapter 6	Forecasting constant price revenue growth	Our decisions and an overview of how we have developed our approach to forecasting CPRG
Chapter 7	Setting standards for quality of service	Our 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 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.
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 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 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.[22]

1.4.1 the GDB DPP determination;

1.4.2 the GTB DPP determination;

1.4.3 models used in determining 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);[23]

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

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

1.4.3.5 the input data model;[24]

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

1.4.3.7 a model used to compare starting prices to prices based on a roll-over of current prices (starting price adjustment model);

1.4.3.8 a workbook which was used to produce charts, tables, and figures for this paper and associated publications (chart book);

1.4.3.9 a model map showing the inter-relationships between the models we have used in setting the price-path;

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

[23] This model now also adjusts forecasts from a real series to a nominal series. Our draft 'expenditure reflation model' previously performed this function.

[24] 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.

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

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

1.4.4.1 updated Strata dashboards;

1.4.4.2 updated supplier evidence where we requested it from suppliers; and

1.4.4.3 Strata's advice to the Commission on updated information suppliers provided.

1.5 The full set of expenditure questions we sent to suppliers, suppliers' responses, and Strata's advice on the responses is also available on our website (these documents are unchanged from our draft decision).

Process for the default price-quality path reset

1.6 This paper is the conclusion of an extended consultation process. This process included consultation on both the Gas DPP and the IM review process, which concluded in December 2016.[25] Submissions received during multiple rounds of consultation are available on our website.[26]

1.7 Attachment A sets out the key steps in the consultation process.

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

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

Chapter 2 Price-quality regulation

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; and

2.2.3 our general decision-making framework for 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**)[27]
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.[28]

2.7 GPBs are also subject to ID regulation. The year-ends that each supplier reports on are specific to each supplier (unlike the DPP, which works to a common September year-end).

Table 2.2 Gas pipeline business year-ends

Supplier	Current ID year-end	Proposed new ID year-end
GasNet	30 June	Unchanged
Powerco	30 September	Unchanged
Vector	30 June	Unchanged
First Gas distribution	30 June	30 September
First Gas transmission (Maui network)	31 December	30 September
First Gas transmission (Vector/Kapuni network)	30 June	30 September

[27] First Gas owns and operates the former Vector and Maui Development Limited transmission networks.
[28] Refer to section 52B(2)(c)(i) of the Act.

2.8 Outside of our setting of the DPP, we are currently consulting on aligning the ID years for First Gas distribution and First Gas transmission with the DPP years for the new DPP regulatory period. We expect to finalise our decision on this shortly after the DPP has been set.[29]

Purpose of Part 4 of the Commerce Act

2.9 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.[30]

2.10 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.

2.11 We promote the interests of consumers of the regulated service by promoting the section 52A(1)(a) to (d) outcomes, consistent with those outcomes produced in workably competitive markets.[31] We do not focus on replicating all the potential outcomes of workably competitive markets; we focus on promoting the section 52A outcomes.

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[29] Commerce Commission, Proposed fast track amendments to information disclosure determinations for First Gas gas pipeline services 2017 – draft companion paper, 26 April 2017.

[30] '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.

[31] *Wellington International Airport Ltd & others* v *Commerce Commission* [2013] NZHC 3289, para 25-27.

2.12 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,[32] and exercise judgement in doing so. When exercising this judgement we are guided by what best promotes the long-term benefit of consumers,[33] and must not treat any of the section 52A(1)(a) to (d) outcomes as paramount.[34]

Purpose of default/customised price-quality regulation

2.13 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.

2.14 To meet the low-cost purpose of DPP regulation, we must take into account the efficiency, complexity, and costs of the DPP regime as a whole when resetting the Gas DPP.

2.15 In the DPPs we have set since we determined the original IMs we have adopted a combination of low-cost techniques, including using information disclosed under requirements set for all suppliers, using suppliers' own forecasts, and using independent forecasts.[35]

Statutory requirements for price-quality path resets

2.16 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 2.3 below.

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

[33] 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.

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

[35] 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 2.3 **Formal requirements and limitations on how we set DPPs**

Section	Information provision	Requirement
Section 52P	Determinations by the 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; • the quality standards the supplier must meet; and • the regulatory period.
Section 53O	Specific 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.

Economic principles

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

2.17.1 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 timeframes 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.

2.17.2 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.

2.17.3 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).

2.18 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.[36]

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

2.19 For this reset, we have retained approaches from the 2013 reset where they remain fit for purpose.[37] We have made changes to the 2013 approaches where those changes:

2.19.1 better promote the purpose of Part 4;

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

2.19.3 reduce complexity and compliance costs.

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

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

2.20 Key contextual factors driving changes include:

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

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

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

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

2.21 This paper has been prepared on the basis of the IMs as amended by our IM review decisions in December 2016.[38]

2.22 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.[39]

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

[39] 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 explain how we have set the 2017-2022 price-path for GPBs. To do this, it covers:

3.1.1 a brief explanation of how we set a price-path for a DPP;

3.1.2 the starting prices we have set for each supplier;

3.1.3 changes since our draft decision to how we have set the price-path;

3.1.4 drivers of changes in starting prices; and

3.1.5 other price-path parameters.

How we set a price-path

IMs 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 In the IM review final decision, 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.[40]

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

3.4 The DPPs we set must specify maximum prices or revenues, and comprise:

3.4.1 the price or revenue limit; and

3.4.2 allowances for pass-through costs and recoverable costs.

[40] Commerce Commission “Input methodologies review decisions: Topic paper 1” (20 December 2016).

3.5 Setting price and revenue limits means that profitability depends on the extent to which costs are controlled. The way we specify price limits for distribution businesses also means that profitability depends on quantity growth (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 reduce costs.

3.6 GDBs also have an incentive to outperform their given demand forecast. Under a weighted average price cap GDBs bear demand risk (the risk of quantities being more or less than forecast at the start of the period). 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 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.[41]

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 have set for each supplier. For instance, we explain how and why we have set 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.

[41] Gas Distribution Services Input Methodologies Amendment Determination 2016 [2016] NZCC 25, clauses 3.1.2 and 3.1.3; Gas Transmission Services Input Methodologies Determination 2016 [2016] NZCC 26, clause 3.1.2 and 3.1.3.

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 $100 million in present value terms.

3.11.2 First Gas transmission would over-recover $63 million in present value terms.

3.12 This is discussed further in paragraphs 3.22 to 3.23 below.

The building blocks allowable revenue approach

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

3.13.1 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

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

3.13.2 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.

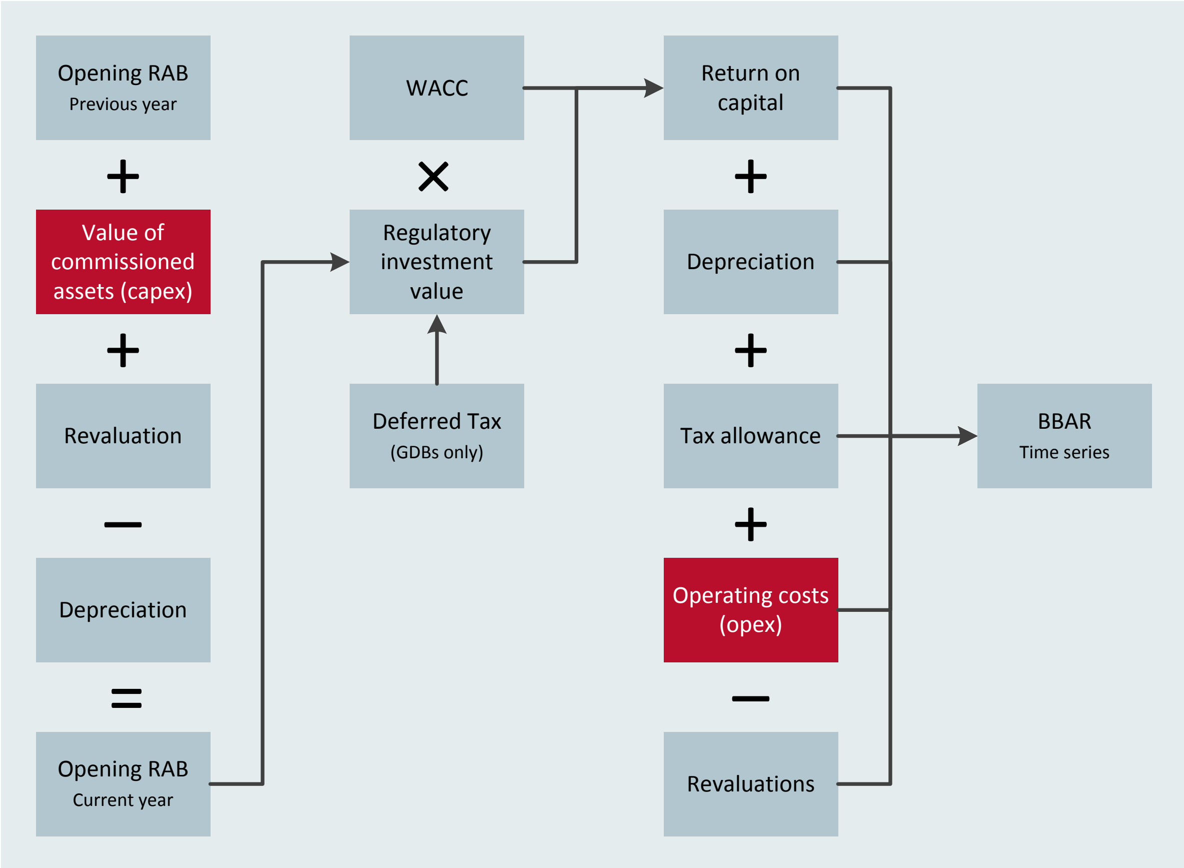
3.13.2.1 A diagram of this step is provided below in Figure 3.2.

3.14 We discuss how suppliers demonstrate compliance with the DPPs in Chapter 8.

3.15 The inputs highlighted in red (capex and opex) in Figure 3.1 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.

3.16 Some other inputs come from ID, while others are specified in the IMs. Some of these ID and IMs inputs are very material, for example, the opening regulatory asset base (**RAB**) (from ID) or the WACC rate (determined based on the IMs).

Figure 3.1 How we calculate BBAR

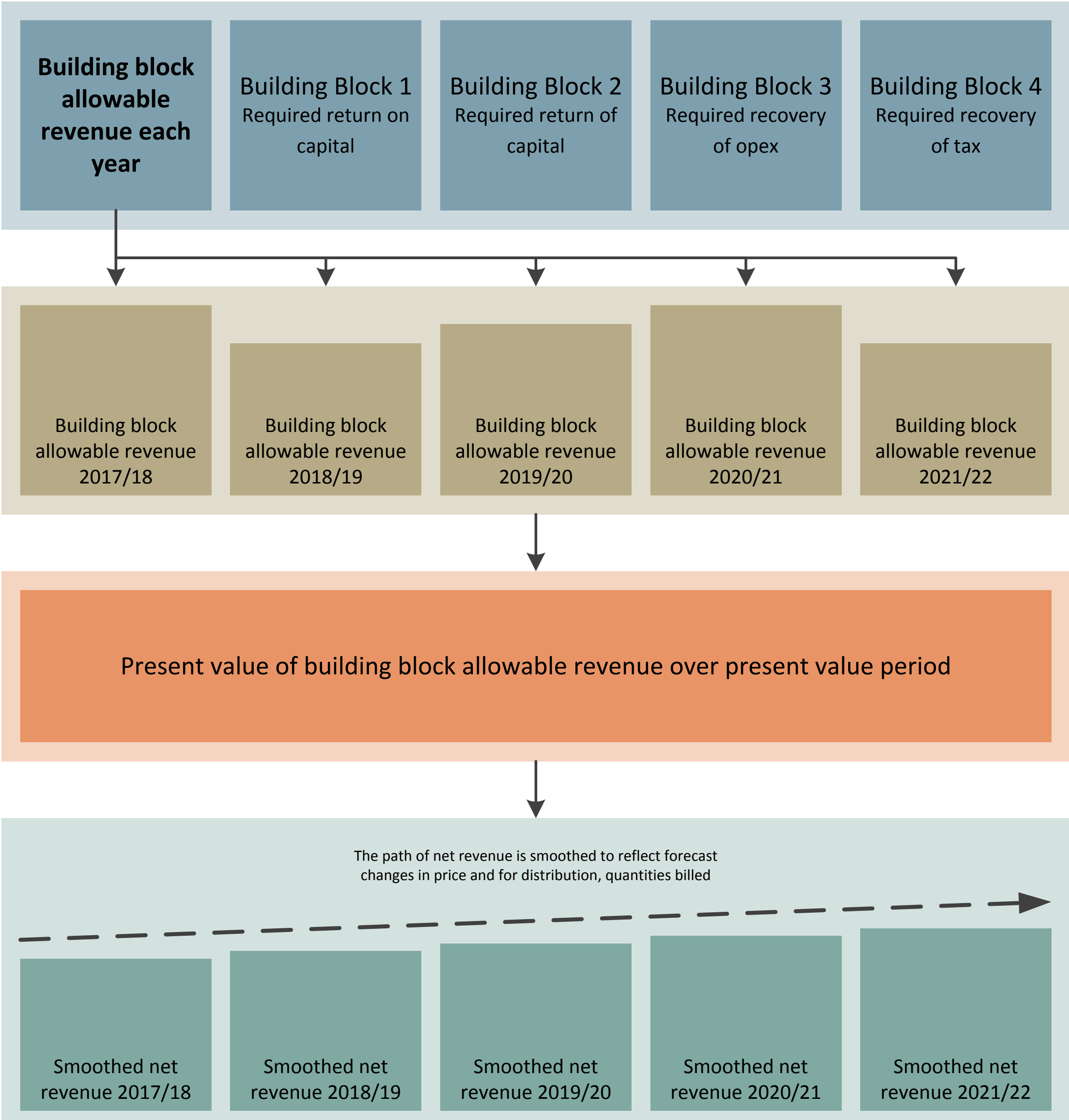


3.17 Our approach is to use forecast capital expenditure as a proxy for the forecast value of commissioned assets, as depicted in Figure 3.1 above.

3.18 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.[42]

[42] Commerce Commission "Model specification for the GPB reset financial model" (1 July 2016). The financial model is avaible on our website at: http://comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/.

Figure 3.2 From BBAR to MAR



From building blocks to starting prices

3.19 These elements combine as building blocks to provide total BBAR for each year of the regulatory period. This BBAR is then smoothed into annual MAR figures through applying CPI, the X-factor, and (for GDBs) the CPRG forecast.[43]

3.20 We smooth this in such a way that the present value of BBAR and MAR are the same. Figure 3.2 above illustrates this process.

[43] Where the X-factor is 0%, for GDBs, this creates a forecast constant real price. For GTBs, it creates forecast constant real revenue flows.

3.21 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 MAR that the regulated supplier can earn over the regulatory period, but not the present value of revenues.

Starting prices

3.22 The five-year time series of MAR (the smoothed revenue illustrated at the end of Figure 3.2) for each supplier is set out in Table 3.1.

Table 3.1 MAR in each year of the regulatory period[44]

Supplier	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022
GasNet	$4m	$4m	$4m	$4m	$4m
Powerco	$47m	$48m	$49m	$50m	$51m
Vector	$44m	$45m	$47m	$49m	$51m
First Gas distribution	$22m	$23m	$23m	$24m	$25m
First Gas transmission	$122m	$124m	$126m	$129m	$132m

3.23 Starting prices are equivalent to MAR in the first year of the regulatory period (2017/2018) and are set out in Table 3.2. Also show is the impact of the reset on suppliers' allowable notional revenue (**ANR**) or forecast allowable revenue (**FAR**) in 2017/2018 compared to a roll-over. There is a significant drop in the prices allowed for the next DPP compared to rolling over current prices.

3.24 This difference indicates that if the prices were simply rolled over from the 2013 GPB DPP, the resulting profits that suppliers would earn be excessive. This underpins our decision to reset prices based on current and projected profitability.

[44] Values in nominal terms.

Table 3.2 Starting prices and impact of the reset

Supplier	Starting prices[45]	Impact of reset on price/revenue cap[46]
GasNet	$4m	-12%
Powerco	$47m	-9%
Vector	$44m	-21%
First Gas distribution	$22m	-20%
First Gas transmission	$122m	-10%
Industry total	$239m	-13%

3.25 Table 3.3 shows this comparison in 30 September 2017 present value revenue terms over the 2017 to 2022 regulatory period.

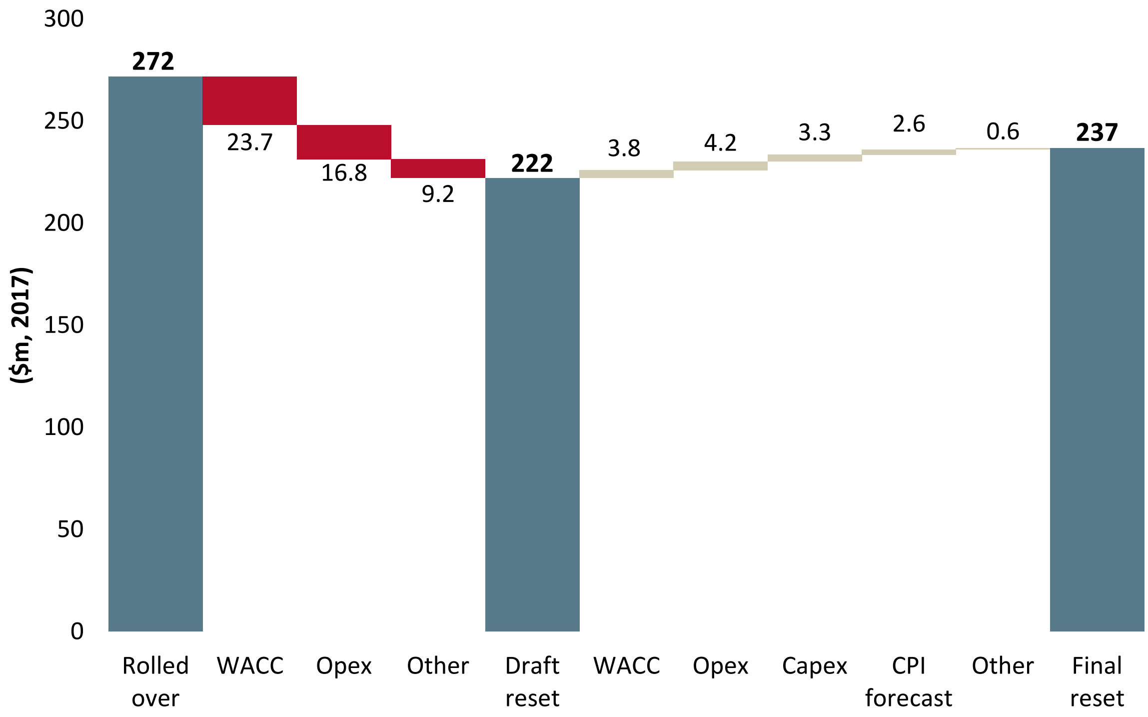
Table 3.3 Estimated revenue over the regulatory period (net of pass-through and recoverable costs)

Supplier	Forecast revenue[47]	Forecast revenue from a roll-over[48]	Forecast over-recovery if prices rolled over[49]	% difference
GasNet	$19m	$22m	$3m	-12%
Powerco	$216m	$236m	$20m	-8%
Vector	$200m	$254m	$53m	-21%
First Gas distribution	$101m	$126m	$25m	-20%
First Gas transmission	$559m	$622m	$63m	-10%
Industry total	$1,096m	$1,259m	$163m	-13%

45 Starting prices are in nominal dollars, for first year of the DPP period (2017/2018).
46 This is the difference between ANR (for GDBs) or FAR (for GTBs) in the first year of the 2017-2022 regulatory period, based on our 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.
47 Estimate of the present value of ANR (for GDBs) or FAR (for GTBs) across the regulatory period, based on the starting prices we have set.
48 Estimate of the present value of ANR or FAR calculated by rolling current prices forward by forecast CPI and, for GDBs by changes in demand.
49 Over the 2017-2022 regulatory period, in present value terms.

3.26 Figure 3.3 illustrates the factors influencing these starting price changes, which are then discussed in the following section of this chapter.

Figure 3.3 Changes compared to a roll-over and from draft to final[50]



Changes from a roll-over to our draft decision

3.27 As is evident in the chart above, the two main drivers of revenue change between rolling over prices and the draft decision were a reduction in the WACC rate and reduction in our opex forecasts.

3.28 The WACC rate used in the 2012 reset was 7.44%, compared to 6.21% in the draft decision. This change was driven by a combination of changing market conditions and changes we have made to the IMs.

3.29 The reduction in revenue due to a decrease in our forecasts of suppliers’ opex is a result of both historic opex expenditure being below the forecasts set in the current DPP and our decision to set opex forecasts lower than suppliers’ AMPs in some cases.

3.30 The ‘other’ category represents a number of smaller expenditure drivers including increased CPRG forecasts, capex forecasts, and changes to CPI.

50 ANR (or FAR) in the first year of the regulatory period.

Changes since the draft decision

3.31 We have made four kinds of key changes since our draft decision that impact how we set starting prices, changes:

3.31.1 to the WACC and cost of debt;

3.31.2 to expenditure decisions;

3.31.3 based on updated data; and

3.31.4 to correct for errors made in our draft decision.

Changes to the WACC and cost of debt

3.32 The WACC estimate we have used to determine starting prices has increased to 6.41 % (compared to 6.21% in our draft decision). The cost of debt has also increased to 4.76% (compared with 4.54% in our draft decision).

3.33 This change is because of a shift in the risk-free rate and the debt premium between January 2017 when we estimated the WACC for the draft decision, and March 2017 when we determined the WACC for the final decision.[51]

3.34 The WACC has also been revised since it was first published in March 2017. This revision was made to bring the WACC determination into compliance with the cost of capital IMs.[52]

3.35 The impact of this revision was a decrease from 6.43% to 6.41%. The resulting industry-wide present value change in revenue over the regulatory period is approximately -$1.2 million.

[51] [2017] NZCC 5 Cost of capital determination – GPBs DPP – 31 March 2017.
[52] Please see Commerce Commission “Notice of revision of cost of capital determination [2017] NZCC 5” (24 May 2017).

Changes to expenditure decisions

3.36 We have made the following key changes to our expenditure assessment decisions based on submissions and additional information provided by suppliers:

3.36.1 accepting Vector's business support opex, and system operations and network support opex forecasts, and changing the way we account for losses in economies of scale;

3.36.2 accepting First Gas' distribution system growth capex forecasts;

3.36.3 accepting First Gas' updated consumer connection capex forecasts;

3.36.4 accepting First Gas' transmission routine and corrective maintenance opex forecasts; and

3.36.5 accepting First Gas' transmission asset replacement and renewal capex (except for the forecast expenditure for the White Cliffs realignment).

Changes to input data

3.37 We have also updated the data used in our modelling based on the most recent ID disclosures from suppliers. These changes affect:

3.37.1 the 'fall-back' forecasts used where we have not accepted supplier AMP forecasts;

3.37.2 CPRG forecasts for GDBs; and

3.37.3 initial conditions data for Powerco.

3.38 We have also updated CPI forecasts we use.

Error correction

3.39 In internal model review between draft and final, an inconsistency was discovered in how we reflate expenditure from real to nominal terms. The year that was used as the base for the nominal calculations was ID year 2017, when ID year 2016 would have been more appropriate.

3.40 We have now included the cost of financing works during construction in our capex forecasts for all suppliers.

Factors influencing starting price changes

3.41 As shown in Table 3.2 our final reset decision has resulted in starting prices that are 13% lower than the prices we would have set based on a roll-over of current prices.

3.42 We have identified three main drivers of starting price adjustments (drivers of the difference between the prices we have set and prices we would have set based on a roll-over of current prices). These drivers are:

3.42.1 the WACC rate for the coming five years is lower than the rate that applies to the current DPPs;

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

3.42.3 increases in CPRG forecasts for GDBs, relative to the forecasts we made for the 2013-2017 DPP.

Reduction in WACC

3.43 The WACC rate used for the 2013-2017 DPP was 7.44%. We have determined a WACC rate of 6.41% for the coming regulatory period.[53]

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

3.45 These changes are captured in Figure 3.4.

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

3.45.2 The right-hand side of the figure (bars in orange) highlights the effect of input parameters on the WACC rate since 2013.

3.46 The impact of these WACC changes on starting prices is shown in Figure 3.5. The chart compares the actual change in starting prices (on the left, in blue) to a scenario where the WACC (and cost of debt) are unchanged from our 2013 decision (on the right, in orange).

[53] [2017] NZCC 5 Cost of capital determination – GPBs DPP – 31 March 2017. The WACC rate we use in our calculations is a 'vanilla' (or pre-tax) rate.

Figure 3.4 Cumulative effect of changes on Vanilla WACC[54]

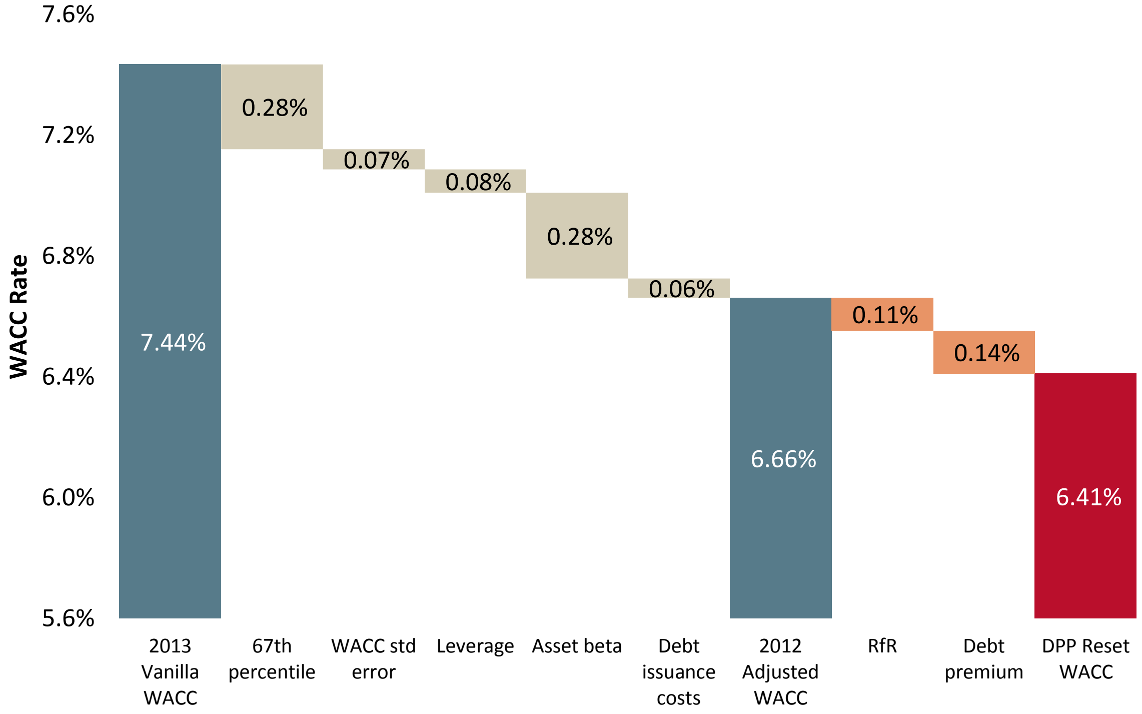
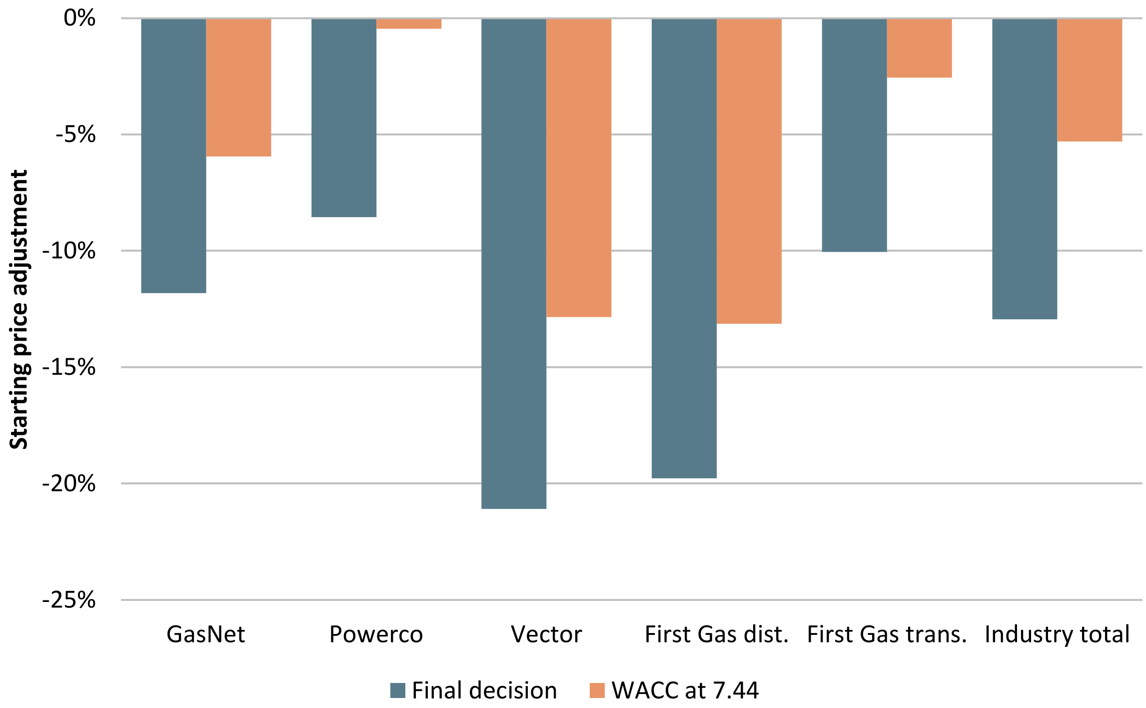


Figure 3.5 Impact of reset on price/revenue cap – WACC scenarios[55]



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54 The WACC was determined as at 1 March 2017, as required by the IMs. The chart is on a non-zero scale.

55 As in Table 3.2, this figure shows the difference between ANR in 2017/18 using a roll-over and our 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.

Opex forecasts

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

3.48 This is partly because actual historic opex (which we use as a starting point for our assessment of supplier forecasts) was lower than our 2013 forecasts. In some cases it is also because our opex forecasts are lower than what suppliers forecast in their AMPs.

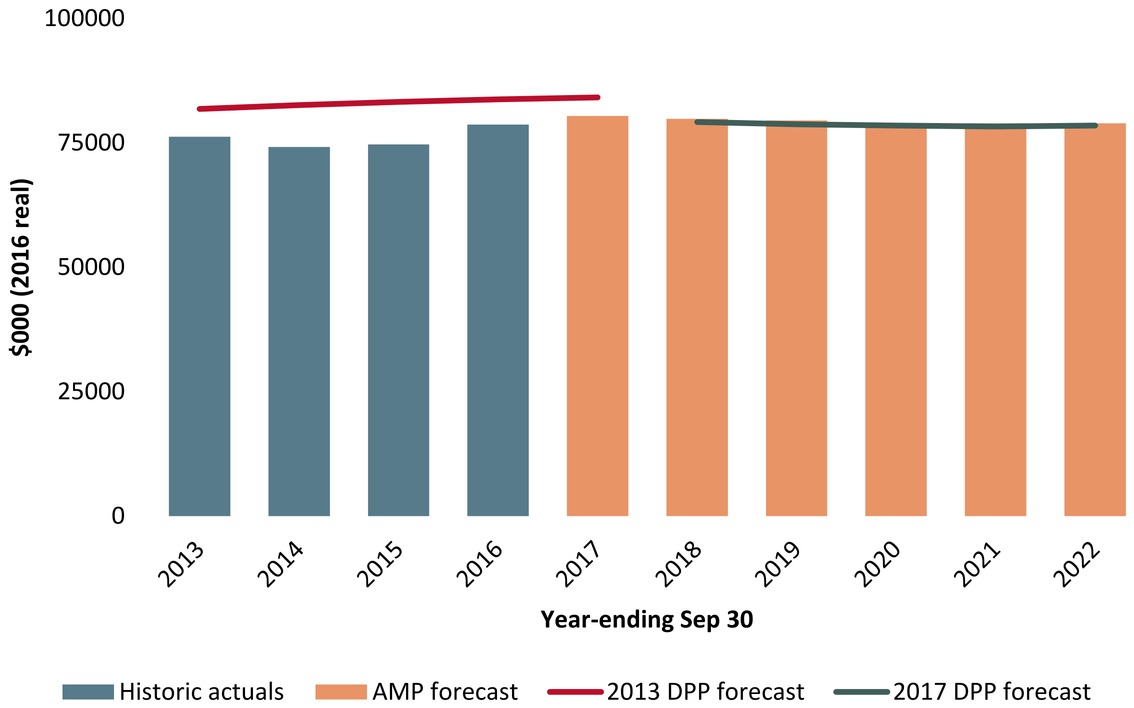
3.49 We have forecast opex using supplier's' AMP opex forecasts as a starting point. We then scrutinised these supplier forecasts, and after making adjustments (as described in Chapters 4 and 5) set our final opex forecasts. In the previous Gas DPP we used a step and trend method to set opex forecasts.[56]

3.50 As outlined in Figure 3.1 above, opex is an independent building block in our BBAR modelling, meaning every dollar of opex allowed is incremental to the BBAR.

3.51 Figure 3.6 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.

[56] This step and trend method is described in Attachment H.

Figure 3.6 Comparison of industry total opex forecasts[57]



Capex forecasts

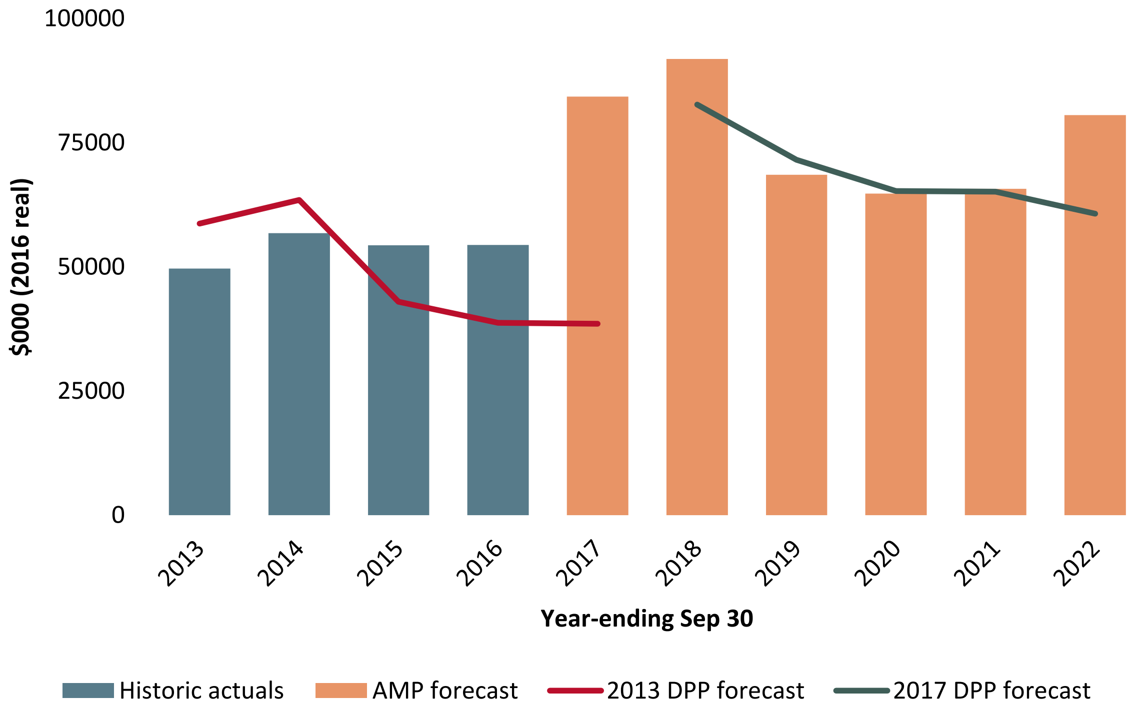
3.52 Both the Commission and suppliers are forecasting a significant increase in capital expenditure over the 2017-2022 regulatory period, relative to the 2013-2017 period.

3.53 Forecast capex is added to the forecast RAB we use to determine the return on capital (WACC) and return of capital (depreciation) for the regulatory period. Because of this, capex forecasts have a less material impact on starting prices than opex forecasts do (and in this case a countervailing, positive impact).

3.54 Figure 3.7 below presents our industry total capex forecasts (from the 2013 DPP reset and the 2017 DPP reset), as well as suppliers' AMP forecasts and historic actual expenditure.

[57] 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. We have changed the way we accounted for inflation of the 2013 DPP forecast to better reflect the impact of opex changes on starting prices.

Figure 3.7 Comparison of industry total capex forecasts[58]



Acceptance of supplier AMP forecasts

3.55 Our expenditure assessment process has led to us accepting the majority of suppliers' opex and capex forecasts. Table 3.4 outlines opex and capex average annual expenditure acceptance rates.[59]

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[58] 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. As with opex, we have changed the way we accounted for inflation of the 2013 DPP forecast.

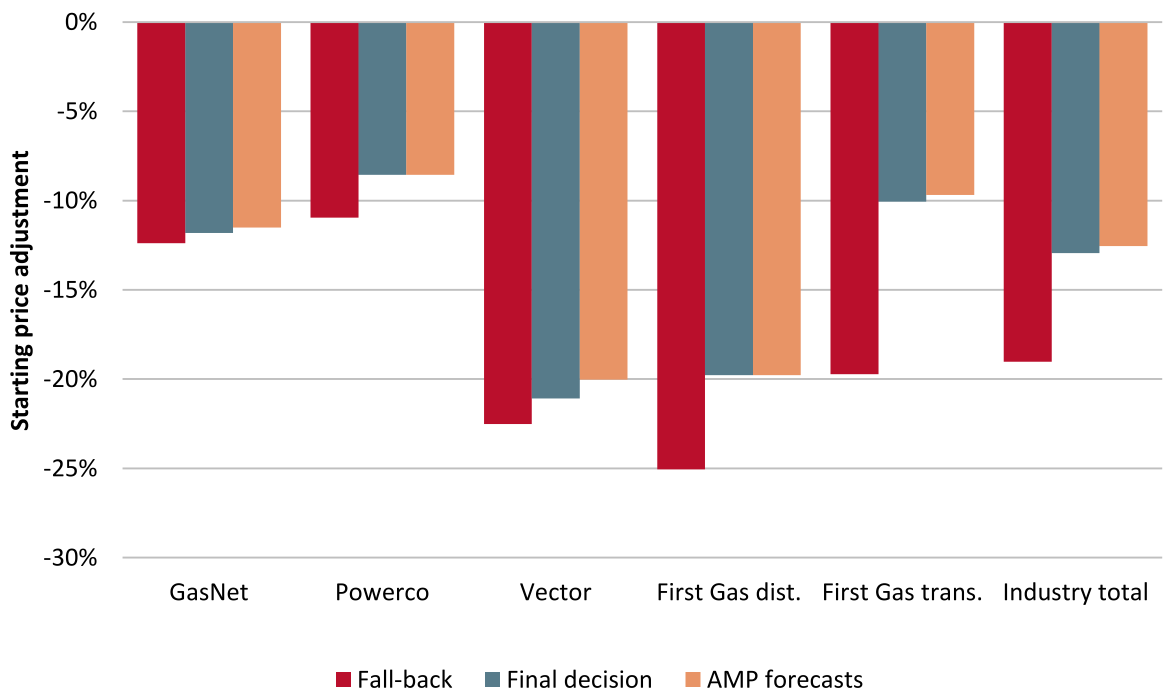
[59] Acceptance rate is the proportion of opex and capex proposed by the Commission relative to what suppliers submitted in their AMPs.

Table 3.4 Opex and capex average annual expenditure acceptance rates

Supplier	Opex	Capex
GasNet	100%	90%
Powerco	100%	100%
Vector	96%	99%
First Gas distribution	100%	100%[60]
First Gas transmission	99%	82%
Industry total	99%	92%

3.56 The impact these decisions have on starting prices is represented in Figure 3.8 below.

Figure 3.8 Impact of DPP reset on price/revenue cap – expenditure scenarios[61]



3.57 Figure 3.8 compares our final decision (in the centre, in blue) to scenarios where we accepted all of suppliers' AMP forecasts (on the right, in orange) and none of suppliers' forecasts above business as usual (**BAU**) levels (on the left, in red).

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[60] This is compared to First Gas' forecasts as updated for consumer connections in their submission on our draft decision.

[61] As in Table 3.2, this figure shows the difference between ANR in 2017/2018 using a roll-over and our final decision across the three expenditure scenarios.

CPRG forecasts under a weighted average price cap

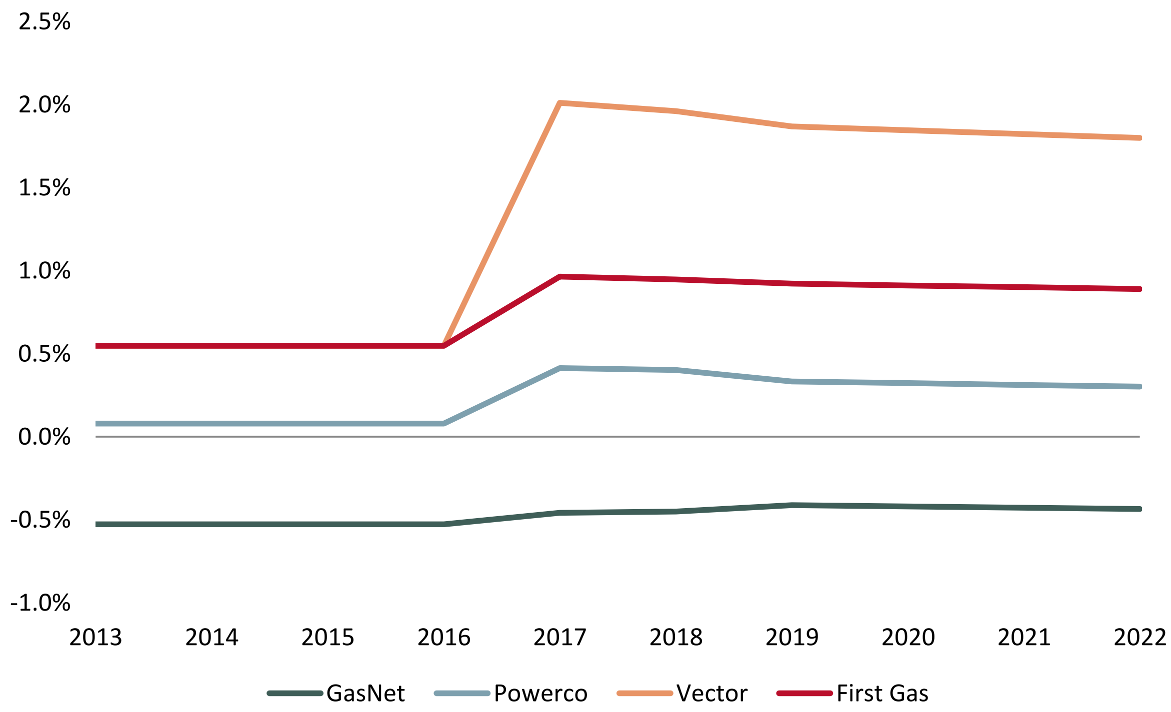
3.58 We are forecasting higher CPRG for all GDBs in the 2017-2022 period than we forecast for the 2013-2017 period. Figure 3.9 illustrates this change.

3.59 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.

3.60 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 over the period. Chapter 6 gives a detailed overview of our proposed approach to forecasting CPRG.

3.61 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%.

Figure 3.9 Comparison of CPRG forecasts[62]



[62] 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.

Other price-path considerations

Rate of change

3.62 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 (either in New Zealand or including overseas markets). We refer to this rate of change in productivity as the 'X-factor'.

3.63 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.

3.64 In the 2013 Gas DPP, we needed to forecast productivity changes both to set the X-factor and as a component of our 'step and trend' approach for forecasting opex.[63] As we have not set opex based on a step and trend method for the 2017 reset, we have taken a simpler approach to setting the X-factor.

3.65 Because of the less material impact of productivity growth forecasts, we have based our decision on the X-factor on recent productivity studies in Australia and North America and historic evidence from New Zealand.[64] This analysis indicates an X-factor of 0% is appropriate.

3.66 Submitting on our draft decision, First Gas (supported by Vector in its cross-submission) suggested we could use the X-factor to smooth price decreases over the period by setting an 'alternative rate of change'.[65]

3.67 While we have the power under the Act to set an alternative X-factor, the circumstances in which we can set one are limited to: [66]

3.67.1 minimising price-shocks to consumers;

3.67.2 minimising undue financial hardship for suppliers; or

3.67.3 as an incentive to improve quality of service.

3.68 As we have no evidence that the starting prices we have set will impose undue financial hardship on suppliers, we see no need to set alternative rates of change.

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63 The X-factor is set based on an estimate of total factor productivity growth, while the step and trend forecasts of opex were set using opex partial productivity growth forecasts.

64 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.

65 First Gas "Submission on the Gas DPP Draft Decision" (10 March 2017), page 12; Vector "Cross-submission on the Gas DPP Draft Decision" (24 March 20-17), paras 5-7.

66 Commerce Act 1986, s53P(8)(a).

Regulatory period

3.69 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.

3.70 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.[67]

Timing assumptions

3.71 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 (such as opening RAB and tax values) for the financial model. As a result of this we needed to adjust the expenditure forecasts by time-shifting those three months.[68]

[67] Commerce Act 1986, s53P(8)(a).

[68] This has been achieved through time shifting the First Gas distribution AMP data with the formula: ID $year_t = (AMP_t * 0.75) + (AMP_{t-1} * 0.25)$. The reverse applies for ID data from MDL.

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 the DPP for the 2017 to 2022 regulatory period.

Expenditure forecasts

4.2 Our expenditure forecasts for each supplier are key inputs for determining starting prices.

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 final 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 In response to submissions on the approach as set out in our August 2016 policy paper,[69] we made significant updates and clarifications to our approach at the draft decision stage. The issues raised in these submissions are discussed in Attachment C.

4.5 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

4.6 We have developed a series of steps for forecasting expenditure that applies to all GPBs based on the principles outlined in paragraphs 4.79 to 4.114.

4.7 The four steps, as set out in Figure 4.1, are:

4.7.1 BAU variance tests;

4.7.2 AMP evidence;

4.7.3 supplier evidence; and

4.7.4 fall-back and alternative forecasts.

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

4.8 In these steps, we categorised the expenditure forecast by suppliers as either 'supported' or 'unsupported'. Supported expenditure was accepted and included at that level in our forecast. For categories of unsupported expenditure, we forecast an amount using the fall-back methods described in paragraphs 4.55 to 4.72, or in some cases using an alternative forecast, as discussed briefly in 4.76 and in detail in Chapter 5.

4.9 Overall, submissions on our draft expenditure framework were supportive, following changes announced in October 2016.[70] However, stakeholders raised concerns with specific aspects of the framework and our application of it. These have been addressed throughout this chapter where appropriate.

4.10 In addition to submissions on the framework, stakeholders provided feedback on how the expenditure assessment process could be improved for future resets.[71] We intend to take these suggestions into account in planning for future resets.

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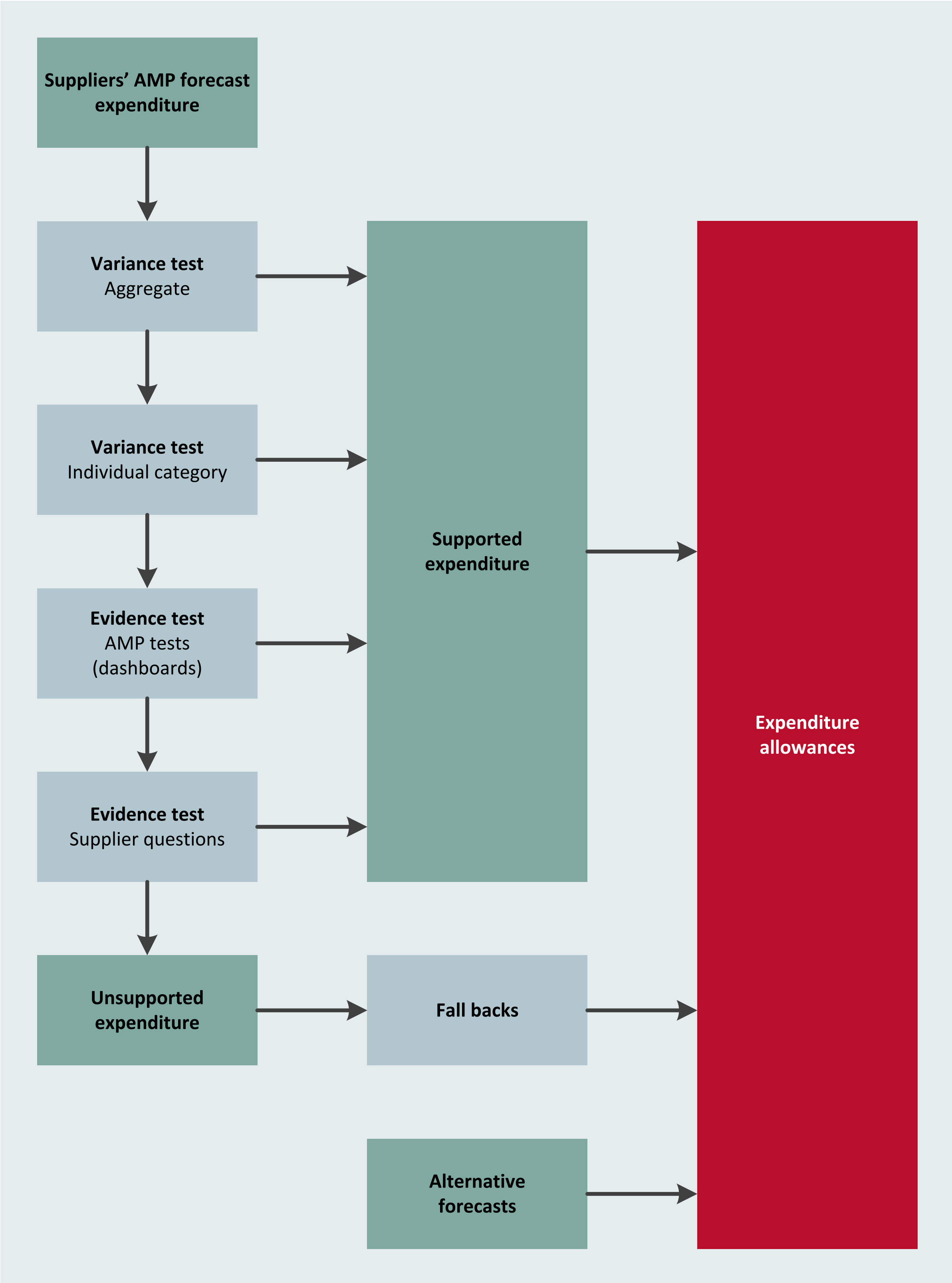
70 Powerco "Submission on the Gas DPP Draft Decision" (10 March 2017), para 7; Vector "Submission on the Gas DPP Draft Decision" (10 March 2017), paras 5-6; First Gas "Submission on the Gas DPP Draft Decision" (10 March 2017), page 20; GasNet "Submission on the Gas DPP Draft Decision" (10 March 2017), page 1.

71 Powerco "Submission on the Gas DPP Draft Decision" (10 March 2017), para 8; Vector "Submission on the Gas DPP Draft Decision" (10 March 2017).

Figure 4.1 Expenditure forecasting steps



Supplier AMP forecasts

4.11 The starting point for our forecasting was suppliers'' own forecasts.[72] Each supplier''s forecast provides a good starting point because suppliers have access to the best information on:

4.11.1 current and future demand drivers for its services;

4.11.2 how to efficiently meet demand for its services;

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

4.11.4 the costs incurred in maintaining and operating the assets.

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

4.12 Our first step in forecasting expenditure was to compare each supplier''s forecast annual expenditure against BAU levels of expenditure.

4.13 We applied variance tests, both at aggregate level and at a category level, of:

4.13.1 a 5% increase above historical average opex; and

4.13.2 a 10% increase above historical average capex.

4.14 For each supplier, we accepted any year of its forecast aggregate opex or forecast aggregate capex as supported expenditure if it was less than the BAU level.[73]

4.15 For suppliers with forecast aggregate opex or forecast aggregate capex above the BAU level, we considered those years of expenditure on an individual expenditure category basis. We accepted any years of individual categories of expenditure as supported expenditure if they were less than the BAU level for that category.

4.16 We applied a more detailed assessment to the categories of expenditure that we did not accept because they were above BAU levels. This assessment was based on the evidence tests described in paragraphs 4.37 to 4.53.

[72] 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 and expenditure models, which have been published as part of our final decision.

[73] All forecasts were assessed in 2016 ID year dollars; June 2016 dollars for GasNet and Vector, September 2016 dollars for First Gas and Powerco.

Calculation of historic baselines

4.17 To derive the BAU variance levels, we needed to calculate supplier's historic average expenditure. For GasNet and Powerco, we applied a standard approach. We have had to estimate or adjust historic baselines for the other suppliers, to account for First Gas' purchase of transmission and distribution assets.

Standard approach for GasNet and Powerco

4.18 Our standard approach to calculating BAU levels was to compare a multi-year annual average of historic expenditure, plus the 5% (for opex categories) or plus 10% (for capex categories) against annual expenditure forecasts for the proposed regulatory period.[74]

4.19 For each supplier where the data was available, we used four years of historic expenditure data as published by suppliers under our ID regime (2013 to 2016). This is a change from our draft decision, where we used a three-year average, as data for 2016 was not available for all suppliers in time for the draft decision.[75]

Combining data for First Gas transmission

4.20 For First Gas transmission, we adjusted the historic baseline by summing the historic expenditure data of the Vector and Maui Development Limited (**MDL**) transmission businesses (accounting for the different year-ends used by Vector, MDL, and First Gas).

4.21 We use a three-year average, as full four years of data was not available for the MDL network.

Backcasting for Vector and First Gas distribution

4.22 For Vector and First Gas distribution, we had to apportion the historic 'old' Vector distribution expenditure between 'new' Vector and First Gas. We needed these values both for use in Strata's dashboard analysis, and to create category BAU levels for the two suppliers. We refer to this as 'backcasting' the suppliers' expenditure.

4.23 The allocation of aggregate opex, network capex, and non-network capex between the two businesses was provided in responses to our 53ZD information request.

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74 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. We have updated this adjustment in our final decision to use inflation figures matched to the year-ends suppliers use for their ID disclosures, rather than December year-end figures in all cases.

75 We signalled this change in our draft reasons paper; Commerce Commission "Gas DPP 2017 – Draft Reasons Paper" (10 February 2017), para 4.27. This was supported by Powerco in their submission; Powerco "Submission on the Gas DPP Draft Decision" (10 March 2017), para 26.

4.24 For the draft decision, we estimated historic expenditure using a combination of Vector and First Gas' 2016 AMP forecast expenditure categorisation and Vector's historic categorisation.

4.25 Our intent with this method was to take into account all available information. However, the complexity of this method introduced uncertainty, and in Vector's view, 'relied too much on the Commission's judgement rather than audited supplier filings'.[76]

4.26 Additionally, the draft method did not recognise how First Gas had re-categorised expenditure. In response to these issues, our approach for the final decision is to use a simpler method based on:

4.26.1 Vector and First Gas' aggregate expenditure breakdowns provided in response to our 53ZD request, to provide the total level of expenditure in each year; and

4.26.2 the proportions of category level opex and network capex from 2016 ID disclosures.[77]

4.27 This approach has resulted in different BAU levels for First Gas and Vector compared to our draft decision. These changes and the impact they had on our decisions are discussed in Chapter 5.

Selection of variance levels

4.28 The variance levels of +5% for opex and +10% for capex strike an appropriate balance between:

4.28.1 identifying areas that require further evidence;

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

4.28.3 recognising the potential reasonable variation in expenditure over time.

[76] Vector "Submission on the Gas DPP Draft Decision" (10 March 2017), para 12.
[77] As non-network capex was itemised separately in the 53ZD request and in the suppliers' responses, we did not need to estimate historic proportions for this category of capex.

4.29 It is appropriate for the variance test level to be higher for capex than for opex because:

4.29.1 capex is more variable than opex;

4.29.2 opex forecasts have a greater impact on the prices consumers pay; and

4.29.3 the incentives to over-forecast opex are stronger than for capex.

4.30 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, while still representing BAU expenditure by the supplier.

4.31 Forecast opex is all recovered through prices during the regulatory period it is forecast to be spent, so any over-forecast of opex has a direct effect on prices. Capex however, is recovered over the entire life of the assets it is spent on. As the RAB we use at each DPP reset is based on actual capex, the impact of over-forecasting capex is more limited.

4.32 As a result of this difference, there is a stronger incentive for suppliers to over-forecast opex than there is to over-forecast capex.

4.33 Responding to our draft decisions, Chris Harvey Consulting (**CHC**) in the course of reviewing First Gas' forecasts submitted:[78]

> The Commission's approach to assessing capex using the historic average of three years with a 10 per cent margin as a threshold and fall-back makes some practical sense as a mechanism to keep the regulatory review process low cost. However, it needs to be recognised that the 10 per cent margin is arbitrary and that capex programs are inherently lumpy, and even regular capex typically has frequencies of much longer than 3 years. Variations from year to year can swing significantly, by as much as 50 per cent or more.

4.34 While we accept that capex especially will show year-to-year variance beyond the 10% threshold, the role of the variance test was to screen expenditure categories for further scrutiny. We chose the 10% threshold to strike a balance between extensive (and high-cost) scrutiny of small variations and the need to gain comfort that supplier forecasts were reasonable.

4.35 Powerco accurately summarised our intent behind the variance tests, submitting on our draft decision that the choice of 5% and 10% thresholds was a "pragmatic and low-cost approach to determine categories of forecast expenditure that require further scrutiny".[79]

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78 CHC (on behalf of First Gas) "Review of First Gas's opex and capex forecasts" (March 2017), para 24.
79 Powerco "Submission on Gas DPP Draft Decision" (10 March 2017), para 12.

Individual categories of expenditure

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

Table 4.1 Individual categories of expenditure

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

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

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

4.37 Prior to the draft decision, we engaged Strata, as consulting engineers, to help us scrutinise evidence for the areas of expenditure that we did not accept under the BAU test. This scrutiny is what we have called the ‘AMP evidence’ and ‘supplier evidence’ steps of our forecasting process.

4.38 For the draft decision, Strata made recommendations to us on whether there were reasonable explanations for expenditure above the BAU variance levels. We considered evidence provided by suppliers (in their AMPs and in response to requests) as well as 'Strata's recommendations for each supplier and accepted or rejected the expenditure on that basis.

4.39 Following the draft decision, we repeated this process if suppliers provided additional evidence in support of their forecasts. The outcomes of these additional assessments are detailed in Chapter 5.

Expenditure objective for assessing evidence

4.40 At all stages, we were assessing the reasonableness of explanations for expenditure against the following expenditure objective:

> 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.

4.41 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 expenditure is prudent and efficient (as is done for a CPP application).

4.42 The expenditure objective is explained in more detail in paragraphs 4.90 to 4.96.

Asset management plan evidence

4.43 The AMP evidence step involved performing a review of the supplier AMPs. Relevant metrics and ratios of data derived from the AMPs were used to explore credible and reasonable quantitative explanations for the individual categories of expenditure that were above the upper variance level. For example, for suppliers with increasing levels of consumer connection expenditure, reasonable ICP growth forecasts were a suitable piece of quantitative evidence.

4.44 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.

4.45 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.

4.46 We did not change these metrics between the draft and final decisions, as submissions on the metrics were limited to a single category (First Gas distribution submitting on the drivers of system growth capex, discussed in Chapter 5).

4.47 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.

4.48 We targeted our efforts on the areas of expenditure that had the greatest variances relative to 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.[80]

Supplier evidence

4.49 Where 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 suppliers. It was voluntary for suppliers to respond, and had they not responded we would have forecast those areas of expenditure at the fall-back levels described in paragraphs 4.55 to 4.72.

4.50 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.

4.51 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.

[80] 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.

4.52 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'.

4.53 When developing 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.

4.54 This process was extended after our draft decision, either through additional requests to suppliers, or where suppliers used their draft decision submissions as an opportunity to provide further and better evidence in support of their forecasts. This included having Strata review updated information.

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

4.55 For individual areas of expenditure that were 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 BAU level.

4.56 However, we also provided for two alternative fall-backs for particular situations.

4.56.1 The step and trend model was available as an alternative fall-back level for opex categories if the standard fall-back level would make aggregate opex lower than the step and trend model and if the supplier forecast was originally higher than the step and trend model.[81]

4.56.2 We have applied an additional fall-back for projects or programmes that we rejected because they are better suited to a CPP application.

4.57 The fall-backs are described below in paragraphs 4.58 to 4.72.

Standard fall-back: upper bound of variance test

4.58 We have set the standard fall-back level at BAU level. This is 5% above the historic average for opex and 10% above the historic average for capex.

[81] The step and trend model for opex is described in Attachment H.

4.59 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.[82]

4.60 We agreed that the fall-back positions should be clear and consistent, and the fall-back policy we chose (as communicated in our October 2016 forecasting update) helped to reduce uncertainty prior to the draft decision, and to clarify the discretion that we applied when setting our expenditure forecasts.

4.61 In its draft decision submission, First Gas warned against a mechanistic application of these fall-back positions.[83] We agree with First Gas' view, and have allowed for a degree of flexibility in how we apply the framework, as discussed below in paragraphs 4.73 to 4.77.

4.62 Other submissions were generally supportive of our approach.[84]

Opex step and trend model as an alternative fall-back

4.63 As an alternative to the standard fall-back, we would not have forecast aggregate opex lower than the forecasts from our step and trend model unless the 'supplier's own forecast was 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.

4.64 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.

4.65 We reassessed whether this alternative fall-back applied for our final decision. For all suppliers, either their AMP forecasts were below the step and trend forecast in the first place, or the forecast we set was above the step and trend forecast.[85] As a result, we did not use the step and trend fall-back to set opex forecasts for any suppliers.

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[82] 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.

[83] First Gas "Submission on the Gas DPP Draft Decision" (10 March 2017), page 20.

[84] Powerco "Submission on the Gas DPP Draft Decision" (10 March 2017), page 3; GasNet "Submission on the Gas DPP Draft Decision" (10 March 2013), page 1.

[85] GasNet, Powerco, and Vector all forecast opex in their AMPs below the step and trend forecasts. Our forecasts for First Gas distribution and transmission are above the step and trend forecasts.

4.66 In response to our draft decision, First Gas submitted that "opex may be better suited to analysis at an aggregate level and through the application of a 'step and trend' type model", and that, were we not to accept its opex forecasts for its transmission business, we ought to use the step and trend forecast instead.[86]

4.67 We agree with this submission. However, as we have accepted First Gas' transmission opex based on further information provided in its submission, the step and trend fall-back does not apply.

4.68 For further discussion on our step and trend approach, please refer to Attachment H.

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

4.69 The CPP fall-back acknowledges that if we did not accept expenditure forecasts from suppliers because they represent projects or programmes that should be considered in a CPP application, by implication 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.

4.70 The amount we have included for a CPP fall-back is $800,000 (in 2016 dollars), spread evenly over the period. This figure was chosen:

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

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

4.70.3 because some of the costs can be recovered through the recoverable cost term.

4.71 We applied the CPP fall-back as opex, regardless of whether the expenditure that we 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. We have only applied a maximum of one CPP fall-back for each supplier for the proposed regulatory period.

4.72 Submissions that addressed the CPP fall-back were supportive of its inclusion in our framework.[87]

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[86] First Gas "Submission on the Gas DPP Draft Decision" (10 March 2017), page 22.
[87] Powerco "Submission on the Gas DPP Draft Decision" (10 March 2017), paras 14-16.

Alternative forecasts for supplier-specific circumstances

4.73 In addition to the alternative fall-backs we built into our framework, in some circumstances, there were alternative forecasts which better reflected forecast expenditure over the DPP period than either suppliers' AMP forecasts or our fall-back forecasts.

4.74 As First Gas pointed out in its submission on the draft decision:[88]

> While we broadly support this expenditure review process, the draft decisions highlight that in some cases a mechanistic application will not best achieve the [expenditure objective]

4.75 First Gas further pointed to the effects a rigid application of the framework could have on suppliers' incentives to provided unbiased forecasts and on incentives for efficiency.[89]

4.76 Our expenditure framework was not intended to be mechanistic. Where there was clear evidence (which we could assess in a low-cost way) for a need to make pragmatic adjustments, and where the impact of the decision on starting prices was material, we have done so.

4.77 These forecasts were in most cases either proposed by suppliers in the submission on the DPP draft decision, or were a response to issues raised in submissions on the draft. The situations where we used such alternatives are described in Chapter 5.

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

4.78 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.

Context and principles that underpin our approach

4.79 This section discusses the context for our decisions on expenditure forecasts, and the principles that underpin our approach.

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[88] First Gas "Submission on the Gas DPP Draft Decision" (10 March 2017), page 20.
[89] Ibid.

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

4.80 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.

4.81 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.

4.82 However, under periodic resets, there is now an incentive for suppliers to inflate 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.

4.83 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.[90] Our approach to limiting this problem in the initial GPB DPPs would partially continue this incentive if used repeatedly over multiple resets.[91]

4.84 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:

4.84.1 developed principles that we anticipate will be reasonably stable over multiple DPP resets;

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

4.84.3 implemented this process with specific conditions and parameters that are appropriate for this reset.

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90 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” (1 October 2012), page 12.

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

4.85 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.

4.86 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.

Principles that underpin our approach

4.87 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.

4.87.1 *Expenditure objective* – the expenditure forecasts we set should reflect an explicit expenditure objective that suppliers are being assessed against.

4.87.2 *Low-cost DPP* – we must set DPPs in a relatively low-cost way.

4.87.3 *Tailoring* – a greater level of tailoring in the way we set DPPs can help better promote the long-term benefits of consumers.

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

4.88 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.[92] These principles are key to understanding why we have forecast expenditure using the approach set out in this chapter.

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

[92] 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).

Expenditure objective

4.90 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.

4.91 Establishing an overarching objective that guides our assessment of suppliers'' expenditure forecasts is important. In a process that required 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.

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

4.92.1 right investments (consideration of alternatives);

4.92.2 right timing (not in advance or deferred);

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

4.92.4 right resources to deliver (delivery plan).

4.93 The outcome we are promoting with this expenditure objective remains the same in a DPP and in a CPP. What differs is:

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

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

4.93.3 the level of departure from a BAU level of expenditure we are willing to accept, as a result of these first two points.

4.94 These differences are crucial, and have a material impact on the type of process we implement. Many submissions on our policy paper focused on the similarity of the objectives, while overlooking these differences.[93]

4.95 First Gas, in its cross-submission on our policy paper, rightly identified this issue:[94]

> 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.

4.96 We agree with the Major Gas Users Group's (**MGUG**) view, expressed in response to our policy paper, that:[95]

> 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 DPP in a relatively low-cost way

4.97 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.

4.98 Our process for forecasting expenditure is relatively low-cost. This is because it applied 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.

4.99 Assessing supplier AMPs, and asking for clarification to support expenditure forecasts not described or sufficiently supported in the AMPs is a relatively low-cost way for us to be satisfied that supplier forecasts are likely to meet the expenditure objective.

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[93] 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.

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

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

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

4.101 The metric and ratio approach (described in paragraphs 4.43 to 4.45 and in 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.

4.102 Overall, we applied a much lower level of scrutiny (and therefore cost) in setting the DPPs than we would apply when considering a CPP application.

4.103 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.

4.104 Because of these features, we did not agree with the objections raised in submissions on our policy paper 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

4.105 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.

4.106 Tailoring, when combined with appropriate scrutiny, can promote the long-term benefit of consumers. As set out in our policy paper: [96]

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

4.106.2 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

4.106.3 CPP applications that might otherwise be necessary may be avoided.

4.107 It remains our position that these goals are worth promoting, and that tailoring in a DPP is an effective means of doing so.

4.108 In submissions on our policy paper, stakeholders raised concerns about the implications of greater tailoring and scrutiny. At the same time several were broadly supportive of the principle of tailoring.[97]

4.109 In particular, Powerco expressed its concerns as follows:[98]

> 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…

4.110 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.

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96 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.

97 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.

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

4.111 We did not agree that our forecasting process gives any primacy to tailoring. As discussed in paragraphs 4.12 to 4.36, the variance tests avoided 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. Similarly, we made the decision following submissions on our draft decision to include expenditure in some categories using alternative forecasts to further this objective.

Proportionate scrutiny

4.112 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.

4.113 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.

4.114 We applied 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

4.115 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.

Suppliers are limited in their ability to extract excessive profits

4.116 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.

4.117 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.

4.118 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

4.119 Our 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.

4.120 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.

4.121 The Electricity Networks Association (**ENA**) and Aurora were correct when they pointed out in their submissions on our policy paper that our forecasts should not represent ‘stretch targets’ that build in an expectation of efficiency gains before they have been made.[99]

4.122 GasNet identified this potential problem as a ‘conflation of efficiency incentives and expenditure forecasting objectives’, stating:[100]

> … 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.

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

4.124 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.

4.125 Submissions on our policy paper generally acknowledged the need for scrutiny,[101] although as noted in paragraphs 4.97 to 4.104, many submitters had strong views on the form this scrutiny should take and the costs involved.

[99] ENA “Submission on Gas DPP policy paper” (28 September 2016), para 17; Aurora “Cross-submission on Gas DPP policy paper” (12 October 2016), page 3.

[100] GasNet ENA “Submission on Gas DPP policy paper” (28 September 2016), para 22.

[101] 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.

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

4.126 Incentives for quality of service are principally promoted (within the regime) by the quality standards we set. The expenditure forecasts we set should be adequate to meet these standards.[102] However, they should also take into account other regulatory and commercial requirements for quality of service levels.

[102] 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 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 expenditure forecasts for the proposed regulatory period

5.2 Our forecasts of total supplier expenditure for the proposed regulatory period are provided in Table 5.1.

Table 5.1 Our expenditure forecasts ($000, 2016)[103]

Supplier	Opex	Capex	Total
GasNet distribution	$7,950	$4,104	$12,054
Powerco distribution	$81,503	$66,788	$148,291
Vector distribution	$56,367	$85,936	$142,303
First Gas distribution	$35,305	$49,946	$85,251
First Gas transmission	$212,177	$138,613	$350,790
Industry total	$393,301	$345,388	$738,689

5.3 The remainder of this chapter:

5.3.1 compares our forecasts with historic levels of expenditure and with suppliers' own forecasts;

5.3.2 discusses how we arrived at our forecasts, including situations where we have made adjustments to supplier forecasts, and how these have changed since our draft decision; and

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

Comparisons of expenditure forecasts

5.4 Our expenditure forecasts differ both from historic expenditure levels, and from suppliers' AMP forecasts. This section compares these expenditure levels.

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[103] Sum of expenditure over the regulatory period in 2016 ID-year real prices.

Comparison against historic levels of expenditure

5.5 Table 5.2 compares our forecasts of average annual expenditure over the regulatory period against the historic levels of expenditure (in real $2016 terms). The historic levels of average annual expenditure are based on the four years of 2012/2013 to 2015/2016 where possible.

Table 5.2 Our expenditure forecast: change from historic average[104]

Supplier	Opex	Capex	Total
GasNet	-1%	13%	4%
Powerco	6%	21%	12%
Vector	4%	1%	2%
First Gas distribution	10%	52%	31%
First Gas transmission	2%	53%	18%
Industry total	4%	29%	14%

5.6 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' AMP forecasts

5.7 As described in Chapter 4, our forecasts are based on suppliers' own forecasts with adjustments either:

5.7.1 where high levels of expenditure are unsupported;

5.7.2 where expenditure increases are unsuitable to be considered under a DPP; or

5.7.3 where for other reasons the supplier's circumstances warrant it.

5.8 Table 5.3 shows our expenditure forecasts as a proportion of the suppliers' own forecasts (as a percentage of the total in real $2016 terms).

[104] Comparison made on annual average expenditure, in 2016 ID-year end real prices. For distribution businesses the historic average is a four-year, year-ending 2013-2016 average. For transmission it is an average of the sum of MDL's 2012-2015 and Vector transmission's 2013-2015 disclosures (adjusted for differing the year-ends to a common September year-end).

Table 5.3 Forecast expenditure as a percentage of suppliers' own forecasts[105]

Supplier	Opex	Capex	Total
GasNet	100%	90%	96%
Powerco	100%	100%	100%
Vector	96%	99%	98%
First Gas distribution	100%	100%[106]	100%
First Gas transmission	99%	82%	92%
Industry total	99%	92%	96%

Adjustments to supplier forecasts

5.9 Our final expenditure forecasts are a combination of:

5.9.1 supplier AMP forecasts;

5.9.2 fall-back forecasts based on historic average expenditure; and

5.9.3 alternative forecasts for supplier-specific circumstances.

5.10 In most cases, we have accepted suppliers' AMP forecasts. This section discusses:

5.10.1 the forecasts we have not accepted (excluded expenditure);

5.10.2 expenditure categories we excluded at our draft decision, but have now accepted in our final decision;

5.10.3 expenditure we accepted in the draft , reconsidered following submissions and additional information, but have still accepted in our final decision; and

5.10.4 other adjustments we have made to expenditure forecasts.

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105 Comparison made on 2016 ID year-end constant price basis.

106 This is compared to First Gas' forecasts as updated for consumer connections in their submission on our draft decision.

Excluded expenditure

5.11 Based on our assessment of supplier forecasts, we have declined supplier AMP forecasts of:

5.11.1 GasNet's asset replacement and renewal capex; and

5.11.2 Vector's expenditure on non-network assets.

5.12 We have also rejected First Gas' transmission asset replacement and renewal (**ARR**) capex to the extent that it relates to the White Cliffs project. This adjustment is discussed separately below in paragraphs 5.55 to 5.57.

GasNet's asset replacement and renewal capex

5.13 Consistent with our draft decision, we have not accepted GasNet's ARR capex forecast. For the reasons set out in Strata's report on GasNet's additional information prior to the draft, we are not satisfied that increases in GasNet's ARR capex above the BAU tolerance have been adequately explained.[107]

5.14 We received no submissions on this decision, and so have not changed it for our final decision. However, the fall-back forecast we have used has changed to $1.98 million in our final decision from $1.91 million in the draft decision, as we have included 2016 ID data in calculating the historic average.[108]

Vector's expenditure on non-network assets (capex)

5.15 Consistent with our draft decision, we have not accepted Vector's forecast expenditure on non-network assets.

5.16 Vector's forecast in this category was significantly above the annual BAU level of $1.13m.[109] Vector offered two principal drivers of this increase. The first (set out in its 2016 AMP) was an increase of costs attributable to its Auckland network, given the sale of its North Island distribution network to First Gas:

> $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.[110]

[107] Strata "Recommendations Following Supplier Evidence Assesment Responses – GasNet" (28 November 2016), page 2.

[108] Total expenditure over the 1 Oct 2017 to 30 Sep 2022 period, in 30 Jun 2016 real prices.

[109] Vector and First Gas itemised this category in their response to our July 2016 s53ZD request. We have relied on this data and not relied on our 'backcast' method described in Chapter 4.

[110] Vector "Gas Distribution Asset Management Plan 2016 – 2026" (August 2016) section 9, page 6.

5.17 The second (cited in Vector's response to supplier evidence questions) was increased IT expenditure, in particular cyber security measures: [111]

> Vector is also putting more emphasis on maintaining high cyber security and making sure critical infrastructure is well-protected. As such Vector is anticipating an additional $0.2m p.a. due to IT capex.

5.18 Vector reiterated this driver, with added detail, in its cross-submission on our draft decision.[112]

5.19 Strata recommended not accepting these forecasts, because the spending increases were not clearly linked to the drivers in a quantified way.

5.20 This recommendation, combined with the loss of economies of scale has led us to not accept Vector's AMP forecast in this category.

5.21 In its cross-submission, Vector noted that its expenditure on non-network assets in ID year 2016 was artificially depressed due to project deferrals during the sale of its assets to First Gas.[113] Our use of an alternative fall-back for this category in response to this evidence is explained in paragraph 5.80.

Expenditure accepted following submission on our draft decision

5.22 Based on stakeholder submissions on our draft decision, additional supplier evidence, and updated ID information, we have accepted supplier AMP forecasts in these categories that we had rejected in our draft decision:

5.22.1 Vector's business support opex;

5.22.2 Vector's system operations and network support opex;

5.22.3 First Gas' distribution consumer connection capex;

5.22.4 First Gas' distribution system growth capex;

5.22.5 First Gas' transmission routine and corrective maintenance and inspection opex; and

5.22.6 First Gas' transmission asset replacement and renewal capex (excluding White Cliffs).

[111] Vector "Response to Commerce Commission questions regarding Vector's 2016 asset management plan for our Auckland gas distribution business" (1 Feb 2017), page 2.

[112] Vector "Cross-submission to the Draft Reasons paper for Default Price-Quality Paths for Gas Pipeline Businesses from 1 October 2017 to 30 September 2022" (24 March 2017), para 9.

[113] Vector "Cross-submission to the Draft Reasons paper for Default Price-Quality Paths for Gas Pipeline Businesses from 1 October 2017 to 30 September 2022" (24 March 2017), para 10.

Vector's business support opex

5.23 We have accepted Vector's business support opex forecast as it is now below the BAU tolerance level, based on our updated backcasting method and the inclusion of 2016 ID data.[114]

5.24 We have still adjusted Vector's business support opex for losses in economies of scale, as discussed in Attachment E.

Vector's system operations and network support opex

5.25 We have accepted Vector's system operations and network support opex forecast. This is because, on balance, we consider that its AMP forecasts in this category are a better reflection of Vector's likely prudent and efficient costs during the regulatory period than our fall-back forecasts, which were based on our backcast estimate of its historic costs.

5.26 Our assessment of Vector's forecasts against the backcast estimates showed a significant increase (both in the draft and final assessments) over historic levels, beyond the BAU tolerance boundary.

5.27 To explain these apparent increases, Vector cited:

5.27.1 re-classification of opex between categories;[115]

5.27.2 increased resourcing across its business to deal with growth in Auckland, some of which is allocated to gas distribution; and [116]

5.27.3 increased health and safety and cyber security costs (which do not scale down despite the sale of the non-Auckland network).[117]

5.28 Strata's review of these reasons suggested they are plausible explanations and in particular represented an efficient approach to sharing costs across Vector's different regulated and unregulated services.[118] However, due to a lack of quantification and linking of drivers to costs, Strata recommended not accepting the AMP forecasts.

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[114] Our updated backcasting method and our reasons for changing it are discussed in Chapter 4, paras 4.22 to 4.27.

[115] Vector "Cross-submission to the Draft Reasons paper for Default Price-Quality Paths for Gas Pipeline Businesses from 1 October 2017 to 30 September 2022" (24 March 2017), paras 12-15 and 17.

[116] Ibid, para 16.

[117] Ibid, para 17.

[118] Strata "Recommendations Following Supplier Evidence Assessment Responses – Vector" (28 November 2016), pages 2-3.

5.29 While we consider our updated backcasting method a reasonable starting point for assessing Vector's expenditure, we acknowledge Vector's concerns with using a method based on estimated historical levels, rather than on audited supplier disclosures to set a final expenditure forecast.[119]

5.30 Given the difficulties inherent in establishing objective historic BAU levels, and the plausible reasons for increases cited by Vector (including losses in scale), on balance we consider Vector's AMP forecasts acceptable.

5.31 We consider that the most plausible explanation for increases in this category compared to our backcast estimates is a loss of economies of scale. To that end, Vector's AMP forecasts may represent the prudent and efficient costs of running the network at its reduced scale.

5.32 As with business support opex, we have made what we consider an appropriate adjustment to Vector's AMP forecasts to account for this lost scale during the first part of the regulatory period. This is discussed in Attachment E.

First Gas' distribution consumer connection capex

5.33 We have accepted First Gas' distribution consumer connection capex forecast based on the updated forecasts for this category First Gas provided in response to our draft decision.

5.34 Our concern with First Gas' original AMP forecasts was that they were based on an overestimate of likely ICP growth in the coming regulatory period. In its assessment, Strata stated:[120]

> The growth forecasts are explained as being based on medium level ICP forecasts from COVEC economic consultants and forecast average p.a. ICP growth at 3.3%. However, the COVEC economic consultant report dated 12 August 2014, is focused on forecasting ICP growth in Auckland only.

5.35 First Gas submitted in response to this that they see merit in applying a consistent approach to consumer connection capex and CPRG.[121] In support of this approach they provided updated COVEC forecasts of growth outside Auckland, reviewed by CHC.[122]

[119] Vector "Submission GPB DPP Draft Reasons Paper" (10 March 2017) para 12.
[120] Strata "Supplier evidence assessment in support of draft decision – First Gas" 10 February 2017, page 2.
[121] First Gas "Submission on draft decision" (10 March 2017), page 4.
[122] Chris Harvey Consulting (on behalf of First Gas) "Review of First Gas's opex and capex forecasts" (March 2017), page 1 and 11-12.

5.36 However, First Gas still saw our fall-back forecasts as inadequate to cover its expenditure in this category. They cited a change between its capital contributions policy compared to the previous owners, with First Gas requiring less of the connection cost to be recovered up front through contributions, and more included in the RAB.[123, 124]

5.37 First Gas provided updated consumer connection forecasts in Appendix J of its draft decision submission.[125] These forecasts are higher than our draft decision, but lower than its original AMP forecasts.

5.38 We consider that these updated forecasts are reasonable and consistent with our forecasts of growth used for setting CPRG, and so have accepted them.

First Gas' distribution system growth capex

5.39 We have accepted First Gas' AMP system growth capex forecast based on its justification in its submission on our draft decision. First Gas cited two reasons for apparent increases in system growth capex compared to our BAU level:

5.39.1 system growth capex is in large part driven not by ICP growth forecasts but by peak demand forecasts;[126] and

5.39.2 in anticipation of the sale of the assets, Vector had deferred capex in response to increasing peak demand on the North Island network.[127]

5.40 CHC's report on First Gas' AMP and forecasts supported this view; and that First Gas' approach "is good industry practice and provides a robust basis for planning capacity expansions".[128] From our review of First Gas' information, we agree with CHC's assessment.

5.41 MGUG acknowledged that First Gas' approach to growing the network was consistent with MGUG's view that greater participation and diversifying gas demand is needed.[129]

5.42 Given the reasons cited by First Gas, and the assurance we have taken from its consultants, we have accepted its AMP forecast in this category.

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[123] First Gas "Submission on draft decision" (10 March 2017), page 38.
[124] As we forecast capex net of capital contributions, a reduction in forecast capital contributions of the kind First Gas have pointed to presents as an apparent increase in net capex compared to historic levels.
[125] First Gas "Submission on draft decision" (10 March 2017), Appendix J.
[126] Ibid, page 34.
[127] Ibid, page 35.
[128] Chris Harvey Consulting (on behalf of First Gas) "Review of First Gas's opex and capex forecasts" (March 2017), pages 10-11.
[129] MGUG "Cross-submission on Gas DPP Draft decision" (24 March 2017), paras 15-17.

First Gas' transmission routine and corrective maintenance and inspection opex

5.43 We have accepted First Gas' transmission routine and corrective maintenance and inspection (RCMI) opex forecasts based on the additional information in support of it that First Gas provided in response to our draft decision. In reaching this decision we have also considered submissions from some consumer stakeholders citing the asymmetric risks consumers face with regard to interruptions.

5.44 In its submission, First Gas cited four drivers for the increase in RCMI opex:

5.44.1 re-categorisation of MDL opex into the RCMI category;[130]

5.44.2 increased expenditure for previous unreported MDL off-pipeline assets;[131]

5.44.3 increased geohazard investigation costs necessary to assess the risk profile of its assets over the next ten years and to meet regulatory requirements;[132] and

5.44.4 remediation work as a consequence of these geohazard investigations.[133]

5.45 All of these factors were supported by CHC's review of First Gas' forecasts.[134]

5.46 First Gas also submitted that because of re-categorisation, it is more appropriate to look at its opex forecast in aggregate, rather than at a category level.

5.47 We find these reasons for increased expenditure in the RCMI opex category persuasive, in particular, the need to increase monitoring activity in response to geohazard risk.

5.48 Given MGUG's concerns about the costs and asymmetric risks its members face with regard to outages on the gas transmission system,[135] we consider that a prudent approach to monitoring and remediating geohazard risks reflects consumer demands, and benefits consumers in the long-term.

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130 First Gas "Submission on draft decision" (10 March 2017), pages 22 and 31-32.
131 Ibid, pages 31-31.
132 Ibid.
133 Ibid.
134 Chris Harvey Consulting (on behalf of First Gas) "Review of First Gas's opex and capex forecasts" (March 2017), pages 1, 3, and 8.
135 MGUG "Cross-submission on the Gas DPP Draft Decision" (24 March 2017), para 5.

First Gas' transmission asset replacement and renewal capex

5.49 In response to additional information from First Gas, and based on other stakeholder submissions, we have accepted some but not all of First Gas' increases in ARR capex.

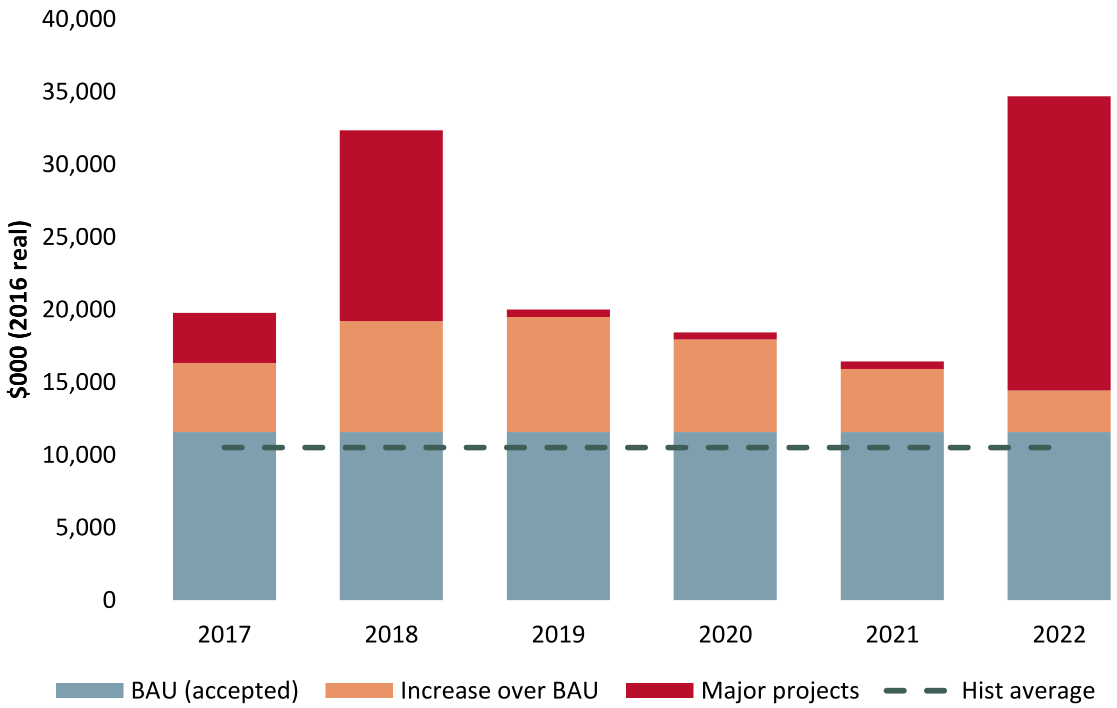
5.49.1 As previously signalled, we have accepted the (urgent) need for First Gas' Gilbert Stream project.[136]

5.49.2 Also as previously signalled, we have not accepted expenditure related to the White Cliffs realignment project.[137]

5.49.3 Based on substantial further evidence provided in submissions, we have accepted First Gas' other programmatic increases in ARR capex.

5.50 The levels of expenditure for each of these major projects, along with the other substantial increases in ARR capex are illustrated in Figure 5.1.

Figure 5.1 First Gas transmission asset replacement and renewal forecasts



[136] Commerce Commission "Updated draft decision on Gilbert Stream expenditure" (23 March 2017).

[137] Commerce Commission "Default price-quality paths for gas pipeline services from 1 October 2017 – Process and issues paper" (29 February 2016), para 3.43; Commerce Commission "Gas DPP 2017 – Draft Reasons Paper" (10 February 2017), para 5.13.

Gilbert Stream

5.51 Alongside our draft decision, the Commission requested additional information from First Gas to justify its Gilbert Stream capex project. This information concerned:[138]

5.51.1 the risk analysis and evidence of the marine erosion effects that have underpinned the Gilbert Stream project being considered a pipeline integrity risk;

5.51.2 details of any industry consultation, discussions and support for the proposed Gilbert Stream pipeline realignment expenditure;

5.51.3 details of any alternatives that were considered for the Gilbert Stream pipeline realignment project; and

5.51.4 details of the economic impact of a pipeline failure in the Gilbert Stream vicinity, estimated outage duration, and any cost benefit analysis that has underpinned the decision to carry out the investment.

5.52 First Gas provided this information to the Commission on 17 February 2017. This information demonstrated:

5.52.1 erosion rates of 0.375 metres/year on average are observed in this location and that pipeline is now 9.6 metres from the cliff edge;

5.52.2 episodic slips may eliminate 10 metres of the cliff at this location supporting First Gas' view of a 10 metres proximity investment trigger;[139]

5.52.3 industry consultation, although not explicit industry support;[140] and

5.52.4 a comprehensive consideration of alternative remediation options and costs.[141]

5.53 While no explicit economic benefit calculation was provided, First Gas referred to the 2011 Pukearuhe incident report which estimated an economic cost of $200 million (a five day outage at $40 million/day).[142]

5.54 Based on this information, we accepted the Gilbert Stream expenditure in an updated draft decision, released on 24 February 2017.[143]

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[138] Commerce Commission "Gas DPP – Commission questions – First Gas" (13 February 2017).
[139] First Gas "Gas DPP – First Gas response to Commission questions – Appendix B" (17 February 2017), page 16.
[140] Ibid, pages 30-50.
[141] Ibid, pages 72-120.
[142] First Gas "Gas DPP – First Gas response to Commission questions" (17 February 2017), para 1.4.

White Cliffs preparatory works

5.55 The White Cliffs project is more suited to a CPP. Applying the proportionate scrutiny approach, expenditure on the level of this project (and the impact accepting it would have on prices) requires scrutiny beyond what can be provided in a DPP. Additionally, a CPP would provide for:

5.55.1 consideration of alternative options;

5.55.2 a greater degree of consumer consultation; and

5.55.3 a contingent project mechanism, where expenditure is not passed through to prices until it is undertaken.

5.56 First Gas transmission forecast approximately $82 million of capex for the White Cliffs project, some of which falls within the 2017-2022 regulatory period. In its response to our request for additional information, First Gas itemised this expenditure, as set out below.[144]

Table 5.4 White Cliffs expenditure ($000, 2016)

Network	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Kapuni system	$750	$2,500	$250	$250	$250	$7,650
Maui system	$750	$4,100	$250	$250	$250	$12,600
Total	$1,500	$6,600	$500	$500	$500	$20,250

5.57 First Gas have acknowledged the need for this project to be the subject of a CPP.[145]

Other programmatic ARR capex

5.58 Even without the Gilbert Stream and White Cliffs projects, there is still a significant forecast (shown in the orange bars in Figure 5.1) increase in ARR for First Gas.

5.59 We have accepted First Gas' other ARR capex because we consider that, on balance, First Gas have demonstrated that it meets our expenditure objective.

5.60 We are willing to accept that these investments are necessary, based on the additional information provided by First Gas and reviewed by CHC. We consider that the costs (to consumers) of an outage due to under-investment over the regulatory period outweigh the risk that some of these investments may not be least-cost.

143 Commerce Commission "Updated draft decision on Gilbert Stream expenditure" (23 March 2017).
144 First Gas "First Gas response to Commission questions – 17 February 2017" (24 February 2017).
145 First Gas "Submission on draft decision" (10 March 2017), page 30.

5.61 Given the relatively low-cost nature of the DPP, there is a limit to the amount of scrutiny we can apply to a supplier's forecasts. Within these limits, we are satisfied with the expenditure First Gas has forecast in this category.

5.62 Additionally, to the extent that First Gas can spend less than forecast while delivering the same outputs, such efficiencies will eventually be shared with consumers at the next reset.

5.63 In its additional evidence, the drivers of this general increase First Gas cited were:[146]

5.63.1 increased in-line inspections;

5.63.2 compressor station upgrades;

5.63.3 geohazard remediation;

5.63.4 replacing assets no longer supported by manufacturers;

5.63.5 modifying piping due to safety concerns;

5.63.6 replacing leaking valves; and

5.63.7 pipeline corrosion prevention system replacements.

5.64 First Gas (supported by their owners First State) stated that a reduction in its ARR capex forecasts would mean a reprioritisation of work and an increase in risks.[147]

5.65 First Gas considered that their increased investment relative to historic levels was in part caused by historic under-investment in the network.[148]

[146] Ibid, pages 2 and 28.
[147] Ibid, pages 19; First State "Submission on Gas DPP draft decision" (10 March 2017) para 48.
[148] Ibid, page 21.

5.66 CHC, in reviewing First Gas asset replacement and renewal plans concluded:

5.66.1 that the transmission ARR capex has been adequately explained by the First Gas supplementary information once the Gilbert Stream and White Cliffs project expenditures are removed;[149]

5.66.2 it is reasonable that White Cliffs should be subject to a CPP;[150]

5.66.3 a fall-back is both arbitrary and unsatisfactory as a basis for forecasting lumpy capex;[151]

5.66.4 that capitalising in-line inspection costs is consistent with industry practice;[152] and

5.66.5 that geohazard remediation works are required for geohazard assessment and costs seem reasonable.[153]

5.67 Some consumer stakeholders supported First Gas' analysis of the need for the expenditure. Nova cross-submitted that by declining the expenditure the Commission risks under-estimating the importance of security and reliability on the network.[154]

5.68 MGUG supported First Gas' reasoning based on First Gas' use of the AS/NZS 2885 risk assessment standard.[155] MGUG also expressed support for CHC's conclusions when reviewing First Gas' forecasts.[156]

5.69 On the other hand, Methanex stated that the uplift was not sufficiently justified, particularly with regards to efficiency, and was more suitable for a CPP.[157] We acknowledge Methanex's concerns regarding efficiency, but have placed more weight on the risk faced by consumers in the event of an outage. Additionally, to the extent that First Gas spends less than forecast, at the next price-path reset any efficiency gains will be shared with consumers.

149 First Gas "Gas DPP – First Gas response to Commission questions – Appendix B" (17 February 2017), page 1.
150 Ibid, para 29.
151 Ibid, para 33.
152 Ibid, para 34.
153 Ibid.
154 Nova "Cross-submission on Gas DPP" (24 March 2017), page 1.
155 MGUG "Cross-submission on Gas DPP" (31 March 2017), paras 9-13.
156 MGUG "Cross-submission on Gas DPP" (31 March 2017), para 12.
157 Methanex "Cross-submission on the Gas DPP" (31 March 2017), page 1. Methanex also expressed concerns that it would not benefit from much of the proposed capex as the capex would be spent downstream from where Methanex connects to the pipeline. As we set expenditure forecasts (and the resulting revenue allowances) at a system-wide level, any concerns about how costs are allocated are outside the scope of the DPP decision.

Accepted expenditure forecasts we have reconsidered but not changed

5.70 Between our draft and final decisions, we have reconsidered some accepted expenditure, but retained our decision from the draft. This applied to:

5.70.1 First Gas' distribution ARR capex; and

5.70.2 Vector's consumer connection capex.

First Gas' distribution asset replacement and renewal capex

5.71 We reassessed but have still accepted First Gas' distribution ARR capex after it exceeded the BAU threshold based on our updated backcast. We have accepted First Gas' AMP capex, based on additional information they provided in response to questions from the Commission.[158]

Vector's consumer connection capex

5.72 We accepted Vector's AMP consumer connection capex in our draft decision, but have not accepted an increase above the AMP forecast. Following technical consultation submissions, Vector enquired about whether it could provide additional evidence in support of forecasts above its 2016 AMP forecasts, as Vector considered these amounts may no longer be consistent with the consumer growth it is anticipating.

5.73 Given the limited time remaining, we were not able to provide a level of scrutiny proportionate to the increase Vector indicated. As such, we have not changed our draft decision.

5.74 We note that the consumer connection forecasts we accepted are broadly consistent with our CPRG forecasts, so to the extent that Vector grow its network above forecast level, it will benefit through higher ANR growth under a price cap.

Other adjustments to supplier forecasts

5.75 In most cases, we have either accepted supplier forecasts or used a standard fall-back. However, in exceptional cases (with both clear evidence and a material impact on starting prices) we have used neither our standard fall-back nor the supplier's unadjusted AMP forecast, for the reasons discussed in Chapter 4.

[158] This information is available on our website at: http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

We have included a CPP allowance for First Gas transmission

5.76 We have included an additional $0.8m in First Gas' transmission opex over the regulatory period. This is because we have declined First Gas' forecast White Cliffs capex on the basis that it is more suited to a CPP.

5.77 Our reasoning for the inclusion of a CPP fall-back is discussed in Chapter 4, paragraphs 4.69 to 4.72

Updated consumer connection capex forecasts for First Gas distribution

5.78 We have used the updated consumer connection forecasts (that are more consistent with forecast ICP growth) provided by First Gas in its submission on the draft decision.[159]

5.79 Our concern with the original forecasts First Gas distribution provided in its AMP was that they were based on an overestimate of forecast ICP growth. In response to this concern, First Gas produced forecasts consistent with the ICP growth forecasts we have used to forecast CPRG.

Supplier-specific fall-back for Vector's expenditure on non-network assets

5.80 We have forecast Vector's expenditure on non-network assets using a three-year (2013-2015) average, rather than the standard four-year (2013-2016) average. While we have not accepted Vector's AMP forecasts in this category, we agree with Vector's submission that 2016 represented an outlier year.[160] As such, excluding 2016 from the calculation of the fall-back is reasonable.

Reduction of Vector's non-network opex to account for economies of scale

5.81 We have reduced Vector's non-network (business support and system operations and network support) opex in the first four years of the regulatory period to account for identified losses in economies of scale.

5.82 This issue is discussed fully in Attachment E.

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[159] First Gas "Submission on Gas DPP Draft Decision" (10 March 2017), Appendix J.
[160] Vector "Submission on Gas DPP Draft Decision" (10 march 2017), page 45.

Exclusion of forecast White Cliffs expenditure for First Gas Transmission

5.83 We have accepted most of First Gas transmission's forecast ARR capex programme based on the additional evidence it provided both after additional questions from the Commission, and in its submission.[161] However, as previously signalled, we do not consider expenditure on the scale and with the uncertainty of options and timing of the White Cliffs realignment appropriate for a DPP. As such, we have deducted this expenditure from our forecasts.

Exclusion of Compressor fuel costs for First Gas' Maui transmission system

5.84 Consistent with our decision in the IM review to make the cost of compressor fuel on the Maui transmission system a recoverable cost,[162] we have excluded the portion of First Gas' forecast compressor fuel opex attributed to the Maui system from our opex forecasts.

Cost of financing

5.85 We have now included the cost of financing works under construction in our capex forecasts for all suppliers.

5.86 We have made this decision to ensure consistency between the approach to capex in our expenditure modelling and the definition of capital expenditure in the IMs. This omission was identified by Vector in an email to Commission staff following our technical consultation draft.[163] The approach we have taken is consistent with our approach in the EDB DPP 2015. [164]

5.87 Our capex forecasts for the draft were built up from category level capex forecasts. As a result, those forecasts excluded cost of financing, which are only included in AMPs at an aggregate level, in nominal terms. We took this approach based on the 2012 EDB DPP and 2013 GDB DPP reset, where we did not make an explicit allowance for the cost of financing.[165]

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161 First Gas "Gas DPP – First Gas response to Commission questions – Appendix B" (17 February 2017); First Gas "Submission on Gas DPP Draft Decision" (10 March 2017); Chris Harvey Consulting (on behalf of First Gas) "Review of First Gas's opex and capex forecasts" (March 2017)

162 See Attachment B

163 Email from Kelvin Binning (Principal regulatory advisor, Vector) to Joseph Highet (Senior Analyst, Commerce Commission), "FW: Commissioned assets forecast 2017 Vector AMP update" 10 May 2017.

164 Commerce Commission "Low cost forecasting approaches – Final decision – EDB DPP 2015 to 2020" (28 November 2014), paras 4.28-4.30.

165 Our reasons for doing this are discussed in: Commerce Commission "Final reasons paper for resetting the 2010-2015 default price-quality paths for 16 electricity distributors" (30 November 2012), paras B26-B27

How we have forecast cost of financing

5.88 We have taken the same general approach to the cost of financing works under construction as we took to capital expenditure categories.

5.88.1 Where the supplier's forecast cost of financing (as a percentage of capex) was less than 10% above historic levels we have accepted the AMP forecasts.[166]

5.88.2 Where the supplier's forecast cost of financing was more than 10% above historic levels, we have set a fall-back forecast at the historic average +10%.[167]

5.89 To implement this allowance, we have taken cost of financing as a percentage of total AMP (or historic +10%) capex, and multiplied that by our real capex forecasts. The resulting forecasts are set out in the 'totals' worksheet of our expenditure model.

5.90 The resulting forecasts are set out below.

Table 5.5 Capex allowances for cost of financing ($000, 2016)

	2017/18	2018/19	2019/20	2020/21	2021/22
GasNet	$0	$0	$0	$0	$0
Powerco	$46	$45	$41	$45	$42
Vector	$86	$88	$87	$90	$84
First Gas dist.	$94	$73	$83	$83	$87
First Gas trans.	$1,157	$838	$687	$683	$591

Treatment of GasNet-First Gas Bay of Plenty asset sale

5.91 First Gas purchased the gas distribution assets built by GasNet in the Bay of Plenty prior to GasNet commissioning the assets.[168] We have accounted for this transaction in our final DPP decision taking into account the costs provided by First Gas in our forecast of the First Gas 2017 capex.

166 This applies to GasNet, Powerco, and Vector.

167 This applied to First Gas distribution and First Gas transmission. The historic values for First Gas distribution come from its 2016 ID disclosures. The historic values for First Gas transmission are based on Vector transmission historic IDs (MDL did not include costs of financing in its disclosures).

168 We are also assessing whether the acquisition raises concerns under section 47 of the Commerce Act.

5.92 This forecast capex (as with all other suppliers' 2017 forecast capex) will be subject to the capex wash-up mechanism provided for in the IMs. The net result will be that the value of these assets up to the point of commissioning, excluding any goodwill which is valued at nil in the IMs, will eventually enter the First Gas RAB when the Bay of Plenty gas distribution assets are commissioned.[169]

5.93 We have not sought to adjust our forecast capex downwards in our final DPP decision by taking account of goodwill included in First Gas' costs, as we do not have details about amounts of goodwill or about other adjustments between purchase and commissioning.

Update from our technical consultation paper

5.94 In our technical consultation paper we indicated we were reconsidering our draft decision, which was to include the full purchase price of the assets in the First Gas forecast capex for the setting of the DPP, because we considered this outcome to be inconsistent with the policy intent of the IMs.

5.95 This reconsideration was due to concerns that First Gas had purchased the gas distribution assets at a price substantially in excess of GasNet's cost to construct them. Had GasNet commissioned the assets prior to sale, clause 2.2.11(1)(e) of the IMs would have restricted First Gas to only including the RAB value of the assets that would have been applied in GasNet's closing RAB value, namely, the cost to construct the assets plus any associated financing and commissioning costs.[170]

5.96 We have not changed our draft decision by applying clause 2.2.11(1)(e) of the IMs (the 'RAB limitation'), as we consider that this clause does not apply to this asset purchase, as at the time of purchase the assets had not yet been used to provide regulated services.[171]

5.97 We consider that the 'RAB limitation' on asset sales between regulated parties cannot be read as applying to sales of assets prior to their commissioning based on a proper interpretation of the IMs.

5.98 The purpose of the IMs is to provide certainty for suppliers and consumers. As such, we consider that First Gas, GasNet, and the Commission must apply the IMs as properly interpreted, even where this may be inconsistent with the policy intent behind them.

[169] Clause 2.2.11(1)(a) of the IMs.
[170] The Major Gas Users Group also cited this concern in its submission on the draft DPP decision.
[171] Refer to clause 2.2.11(1)(e)(ii) of the IMs.

5.99 Accordingly, we consider that the assets must be valued based on GAAP under the general rule in clause 2.2.11(1) of the IMs. However, clause 2.2.11(1)(a) of the IMs provides that the cost of an intangible asset is nil, unless it is a finance lease or an identifiable non-monetary asset. Accordingly, any cost in respect of an intangible asset must be excluded from the GAAP value unless it qualifies to be included under clause 2.2.11(1)(a).

5.100 Under clause 1.1.4 of the IMs 'identifiable non-monetary asset' has the same meaning as under GAAP, save that goodwill is excluded. This means that goodwill must be valued at nil for the purposes of valuing the RAB. We will have the opportunity to test compliance by First Gas with clause 2.2.11(1)(a) at the time it submits its ID for the disclosure year 2017.

5.101 The relevant IM provisions may not fully reflect the policy intent behind them and changes to the IMs may therefore be warranted. This is an issue which requires broader, forward-looking consideration outside the DPP setting process. We will consider amending these rules following the experience we have gained in considering the GasNet-First Gas transaction.

Impact on GasNet

5.102 GasNet did not commission the Bay of Plenty assets prior to sale, so they were not in GasNet's RAB, and so have had no impact on the starting price we have set for GasNet. It did not include any expenditure related to the assets in its AMP expenditure forecasts, so we have not needed to make any changes to GasNet's forecast capex to account for the sale.

Impact on First Gas

5.103 We have included an estimate of the costs of the assets in our capex forecasts for First Gas. This estimate is based on costs provided by First Gas, which we consider the closest available approximation of the value of the assets First Gas will commission, consistent with GAAP.

5.104 However, as noted above, we have not sought to adjust our forecast downwards in our final DPP decision to take account of any estimated goodwill that may be included in First Gas' costs. This is because we do not have details of the amount of goodwill, or what the impact of any other changes between purchase and commissioning may be. We have used the forecast capex to forecast the opening RAB value of the First Gas RAB for the start of the regulatory period.

5.105 The capex wash-up mechanism provided for in the IMs washes-up for any difference between the forecast capex in the final year(s) of the current regulatory period and the actual commissioned capex calculated in accordance with the IMs, to ensure that the opening RAB for the DPP period matches the opening RAB disclosed under ID. Any adjustment is given effect through a recoverable cost.

5.106 The value of this recoverable cost will be determined based on the First Gas ID for the disclosure year 2017. First Gas must apply the ID IMs when preparing these disclosures, including the provision which values any non-qualifying intangible assets (including goodwill) at nil.[172] We consider any amount of the purchase price paid by First Gas for non-qualifying intangible assets must not be included in the RAB and must not be recovered through prices.

[172] Clause 2.2.11(1)(a) of the IMs.

Chapter 6 Forecasting constant price revenue growth

Purpose of this chapter

6.1 This chapter explains the role of CPRG in the setting of a price-quality path for GDBs and sets out our decisions on CPRG for the 2017 Gas DPP.

CPRG forecasts

6.2 Table 6.1 below shows the CPRG forecasts.

Table 6.1 CPRG forecasts

GDB	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
GasNet	-0.46%	-0.45%	-0.41%	-0.42%	-0.43%	-0.44%
Powerco	0.41%	0.40%	0.33%	0.32%	0.31%	0.30%
Vector	2.01%	1.96%	1.87%	1.85%	1.82%	1.80%
First Gas distribution	0.96%	0.95%	0.92%	0.91%	0.90%	0.89%

6.3 These forecasts are higher than they were for the previous DPP for all suppliers.

6.4 This chapter outlines CPRG forecasts that are informed by both historical ID information and a forecast from Concept Consulting. The increased CPRG forecasts have been driven predominantly by increased trended historic growth captured through ID and an information request.

Changes since draft decision

6.5 We have updated our CPRG forecasts using the most recently available data from each supplier's ID disclosures. We have applied the same forecasting method, and used the same Concept Consulting demand forecasts as we did in our draft decision.

Impact of CPRG on starting prices

6.6 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 CPRG forecasts are used

6.7 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.[173]

6.8 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.[174, 175]

Context of CPRG decisions

Form of control decisions and the need for CPRG

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

6.9.1 maintain a weighted average price cap for GDBs and continue to use lagged quantities;[176] and

6.9.2 maintain a revenue cap for GTBs, but move to a pure revenue cap allowing for wash-up of over- and under-recovery.[177]

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

Forecasting approach

6.11 After considering the performance of the approach used in 2013 and the views of stakeholders, we have adopted a similar approach for GDBs to that used in the previous Gas DPP.[178]

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[173] 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/.

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

[175] 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.

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

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

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

6.12 The major change from 2013 is that we have further tailored CPRG forecasts to better reflect the operating environments of the individual GDBs. More specifically, we have used gas demand forecasts that relate to the region in which each gas business operates.

6.13 Concept Consulting, on behalf of the GIC, 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 and Lower North Island, Auckland, Non-Auckland, and Whanganui regions.

6.14 We have used 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.[179]

Why we are changing the 2013 approach

6.15 Our approach retains forecasting approaches where they remain fit for purpose. In the process and issues paper published on 29 February 2016, we stated that:[180]

> 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.

6.16 Submitters on the policy paper generally supported using this forecast prepared by Concept Consulting: [181, 182]

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

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

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

[181] First Gas "Submission on Gas DPP policy paper" (28 September 2016).

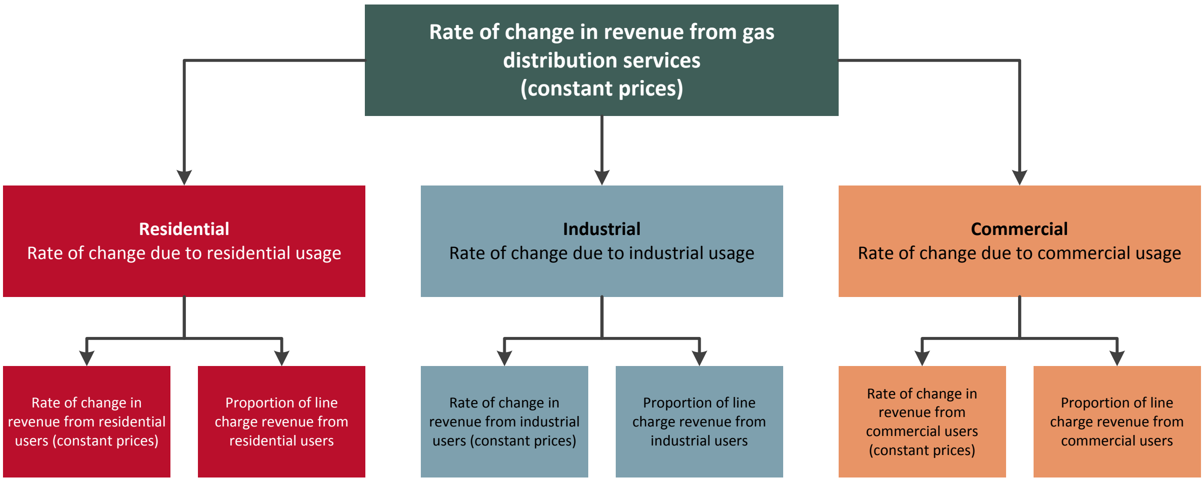
[182] Powerco "Submission on Gas DPP policy paper" (28 September 2016).

Structure of the CPRG model

Three gas user groups modelled for GDB CPRG forecasts

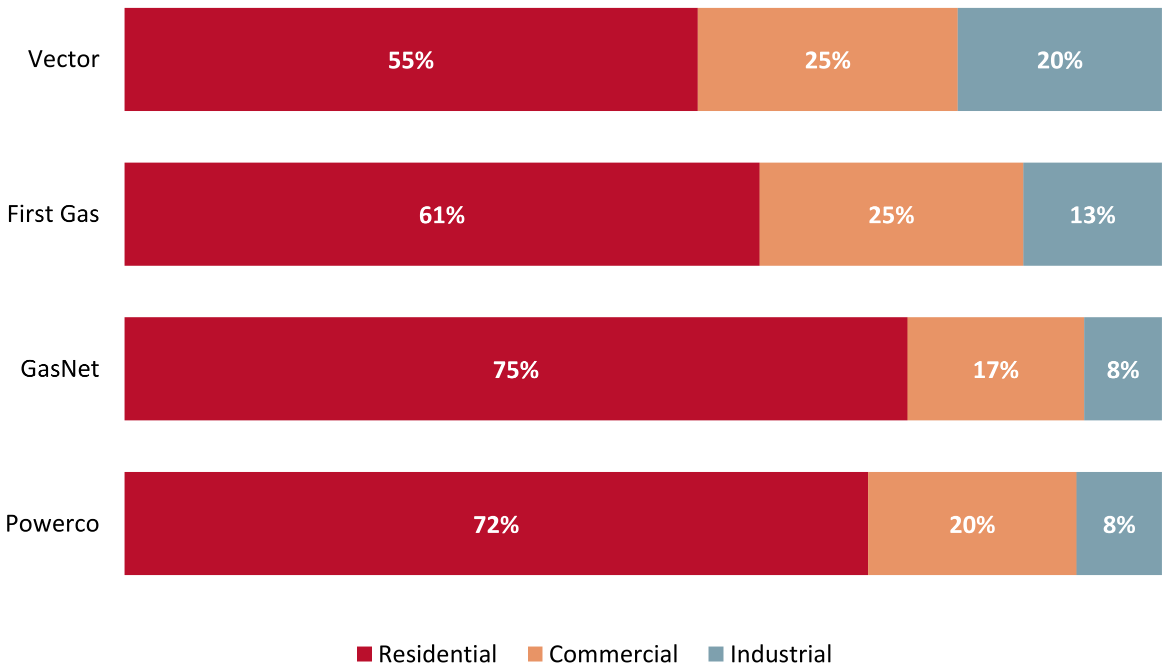
6.17 In line with the previous Gas DPP, we have modelled CPRG separately for each of the three gas user groups: residential, industrial, and commercial users. Once again, we have relied on load group information from suppliers' ID. Figure 6.1 highlights this approach.

Figure 6.1 Modelling constant price revenue for gas distributors



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

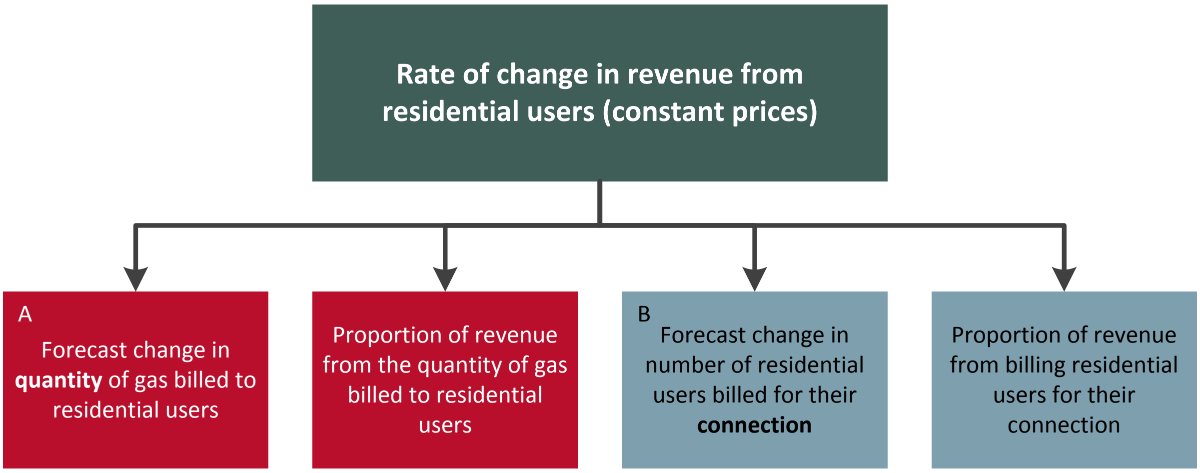
Figure 6.2 User group revenue breakdown by distribution business (2016 disclosure year)



Disaggregation of revenue by charging structure is retained

6.19 Our approach to modelling CPRG aligns 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

6.20 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. This disaggregation by user group is important as suppliers have quite different pricing profiles.

Figure 6.4 Composition of revenue from residential users (2016 disclosure year)

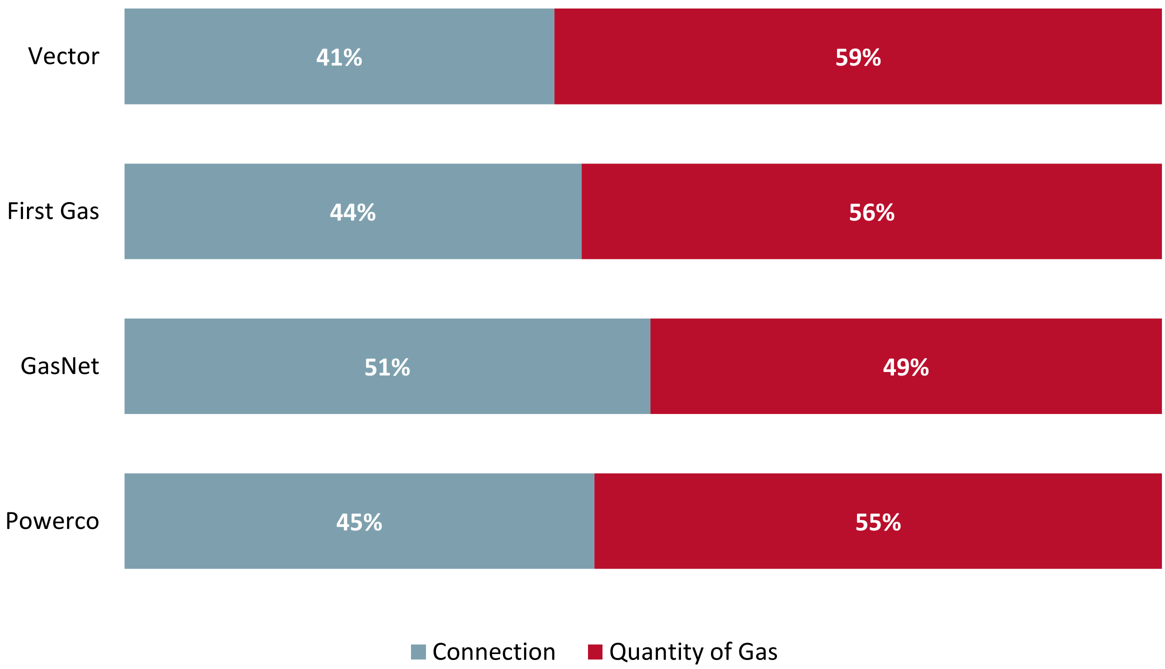


Figure 6.5 Composition of revenue from commercial users (2016 disclosure year)

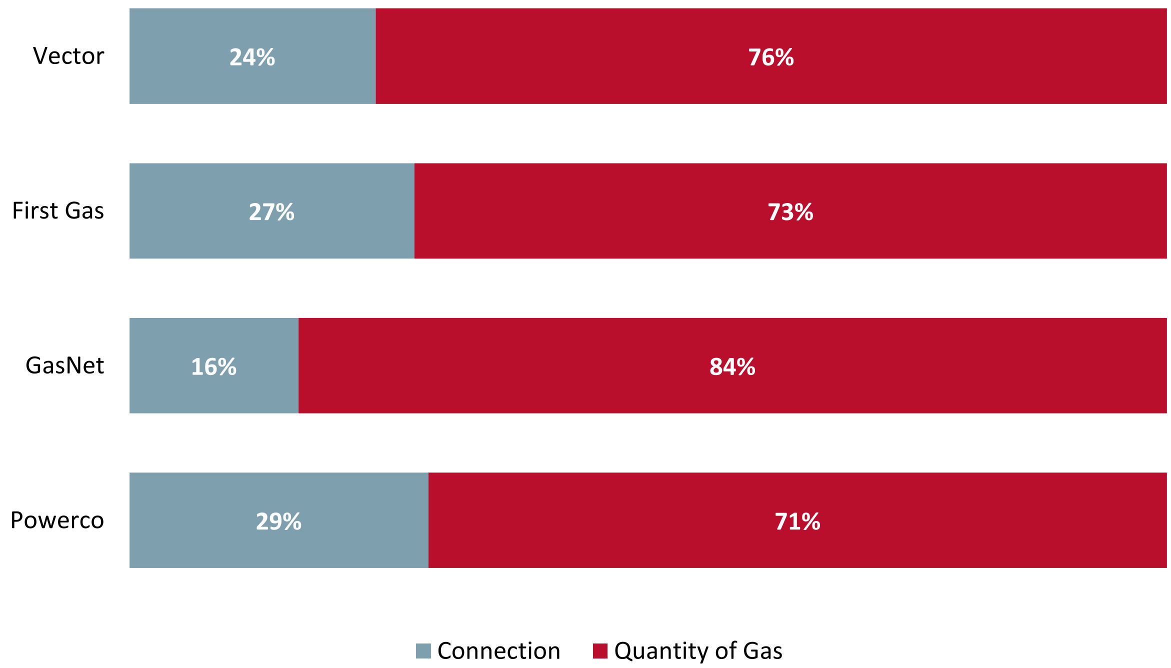
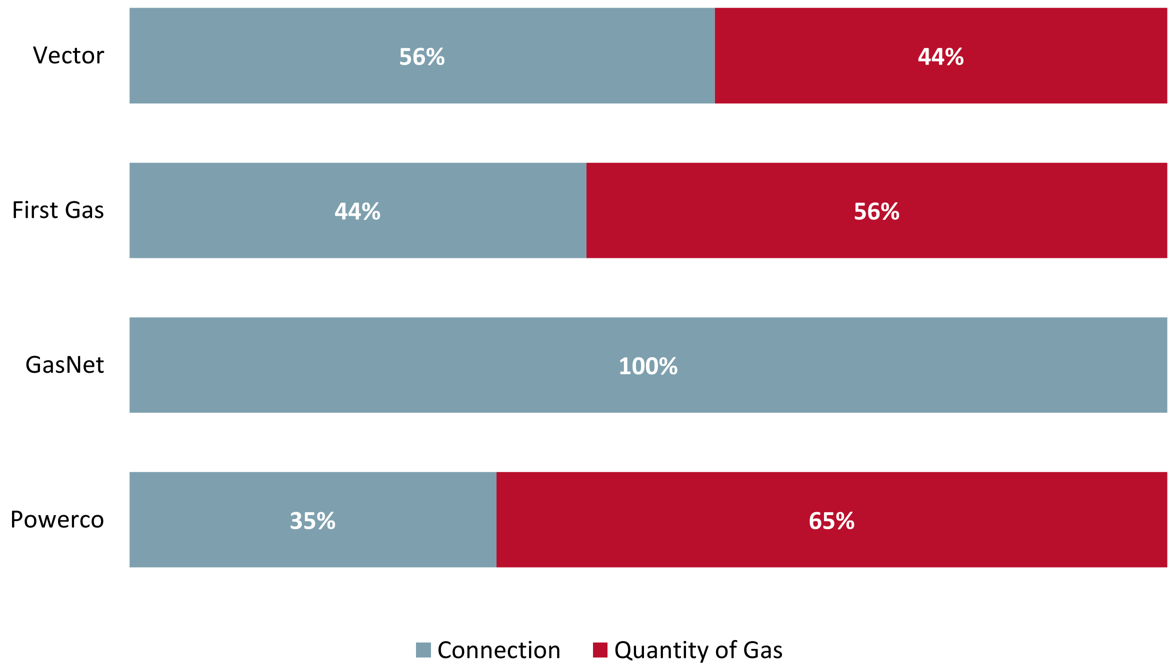


Figure 6.6 Composition of revenue from industrial users (2016 disclosure year)



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

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

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

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

6.22 These tailored, regional forecasts are representative of the following areas, which we have mapped to the GDBs networks:

6.22.1 Central North Island (Powerco)

6.22.2 Lower North Island (Powerco)

6.22.3 Auckland (Vector)

6.22.4 Non-Auckland (First Gas)

6.22.5 Whanganui (GasNet)

6.23 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.[183]

6.24 Figure 6.7 shows the forecast gas demand growth rates by region and at a total North Island level.

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

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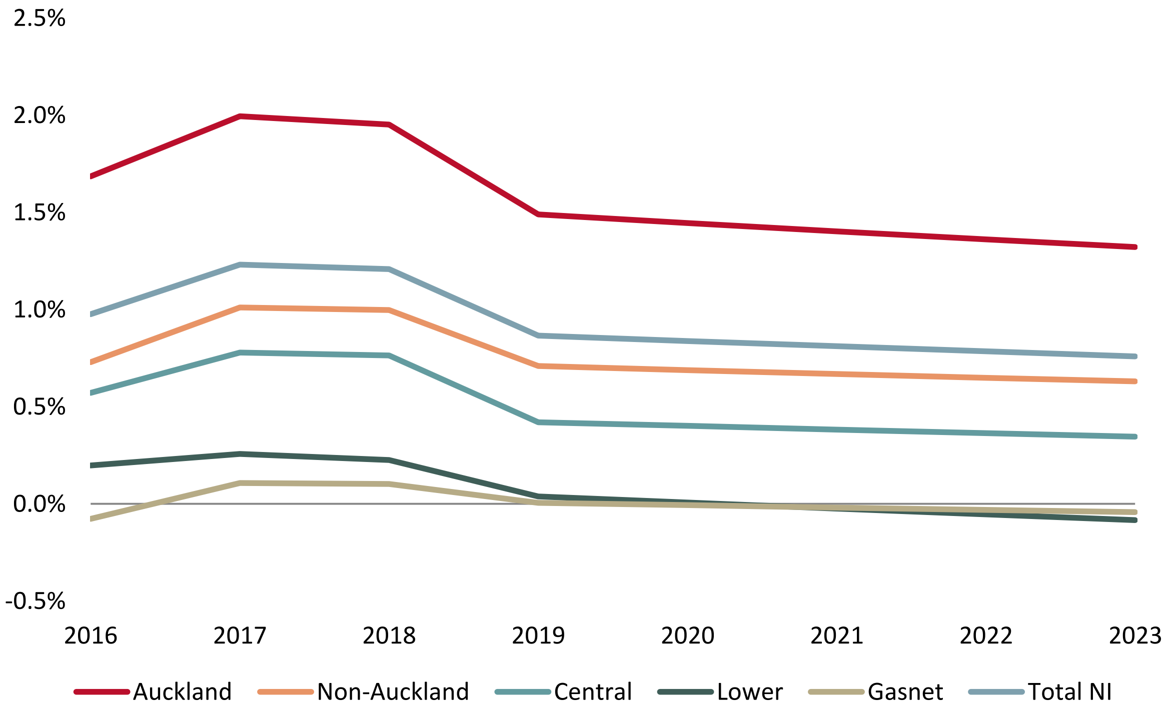
[183] In 2013 we had to make assumptions in order to apply Concept Consulting's moderate scenario – see Commerce Commission, "Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services" (28 February 2013), para E30.

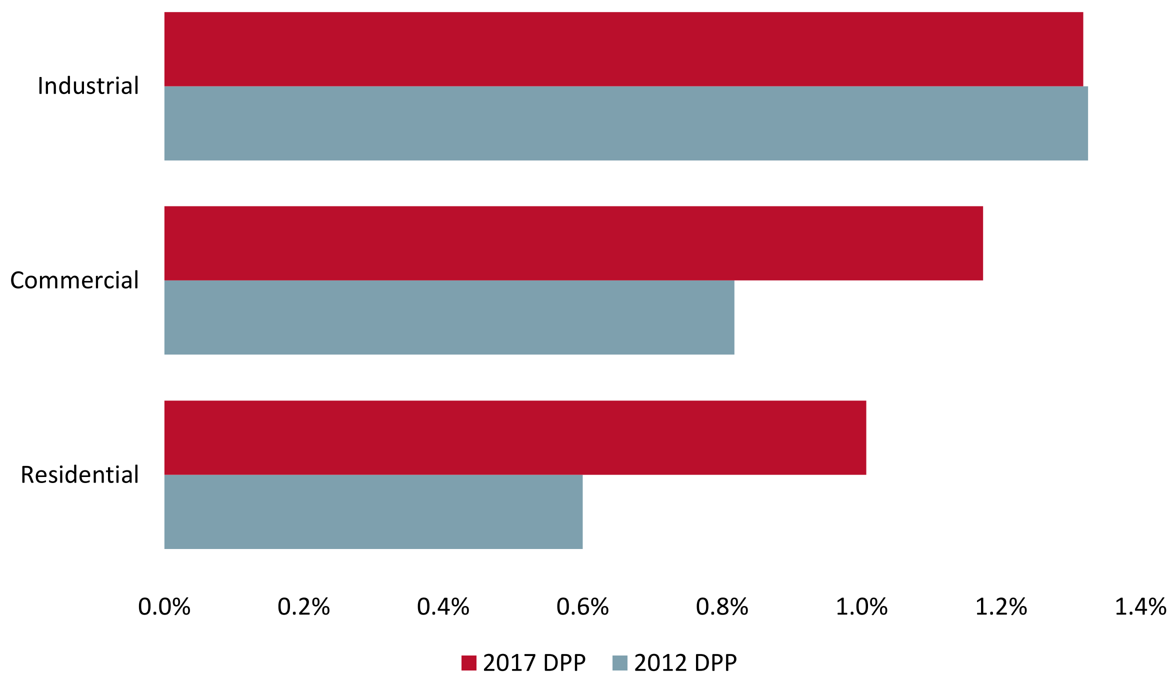
Figure 6.7 Forecast gas demand growth rates by region and total North Island – mid-scenario report by Concept Consulting



6.26 If we aggregated the Concept Consulting report to a total North Island level, as shown in Figure 6.8, the overall growth is broadly similar to that obtained from the gas demand report prepared by the GIC and used for the previous Gas DPP.[184]

[184] "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 2013 and 2017 Gas DPP resets



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

6.27 To forecast the change in revenue from per connection charges ('B' in Figure 6.3) we take the trend in the number of historical 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 2016.

Growth in suppliers' fixed and variable quantities from Information Disclosure

6.28 Figure 6.9 to 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 four years.[185] Where billed kWh increases while the number of ICP's decreases, it indicates that consumption per ICP is increasing.

[185] For the purposes of extrapolation, we have transformed the ID variables into natural log values and taken a trend to arrive at a robust estimate of trend growth.

Figure 6.9 Powerco ID data – trend in 2013 – 2016 logged values

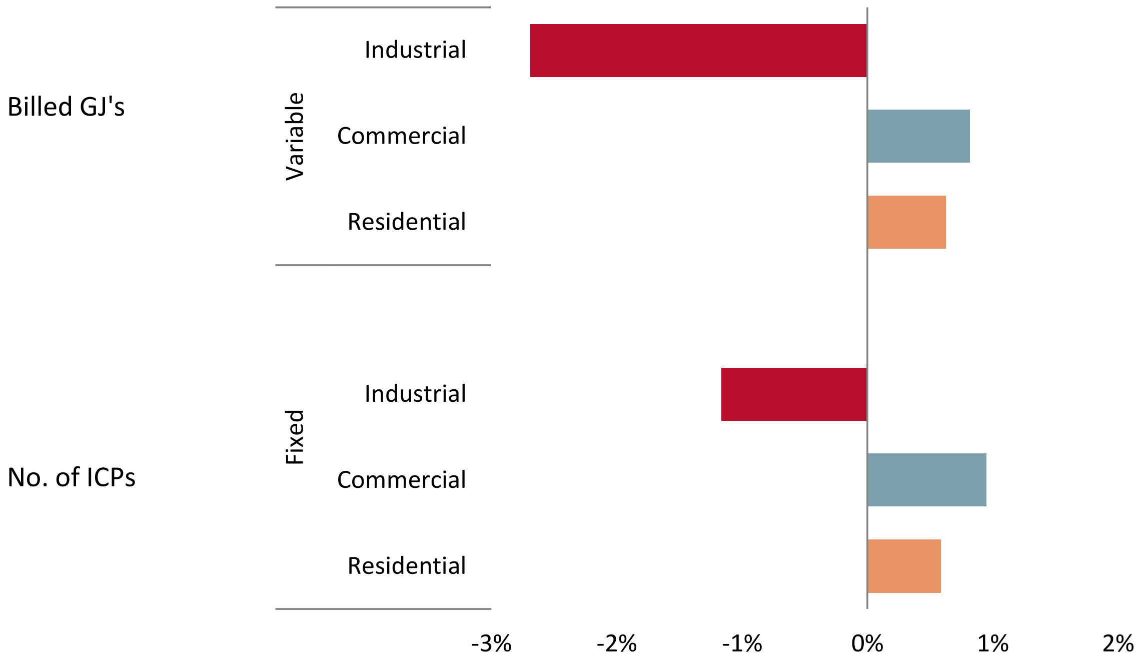


Figure 6.10 GasNet ID data – trend in 2013 – 2016 logged values

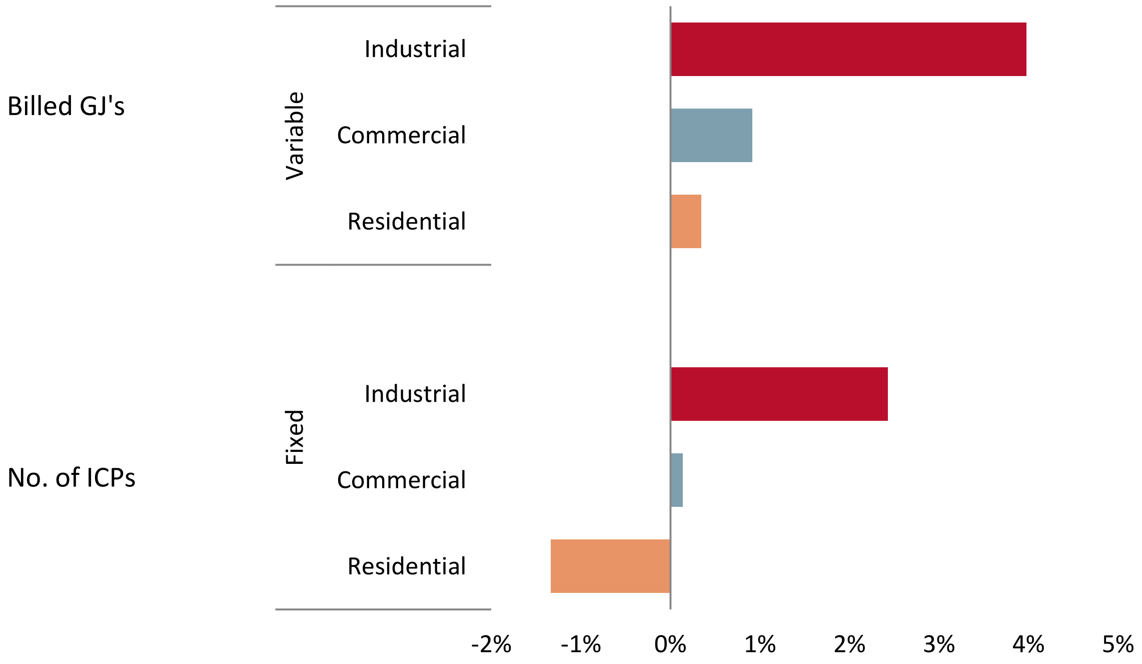


Figure 6.11 Vector ID data – trend in 2013 – 2016 logged values

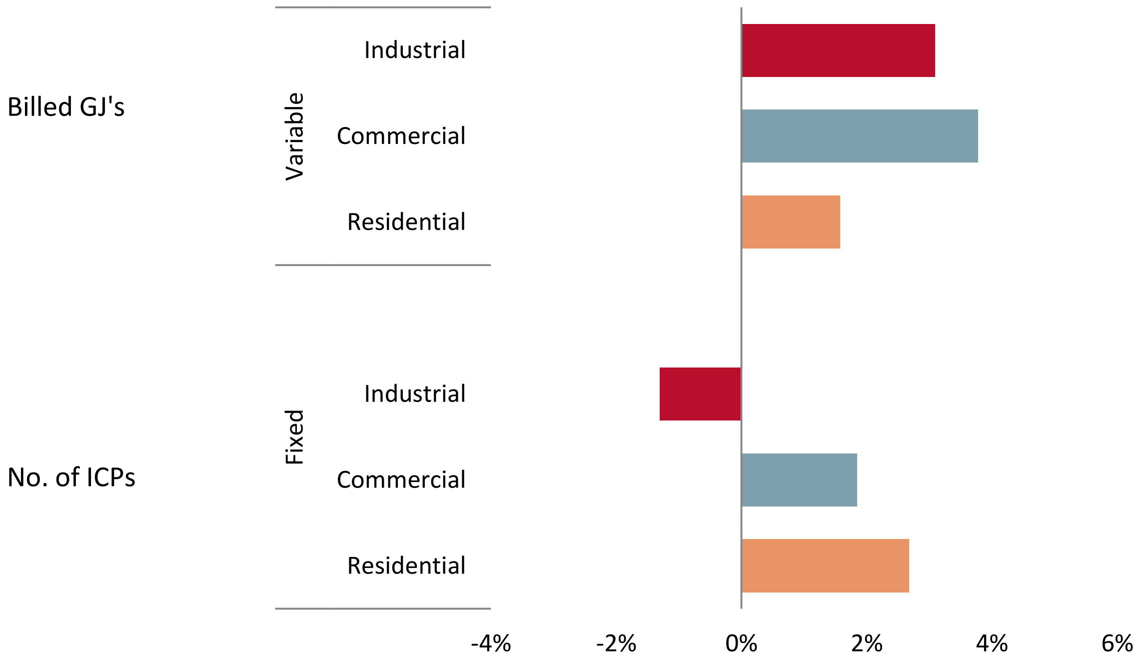
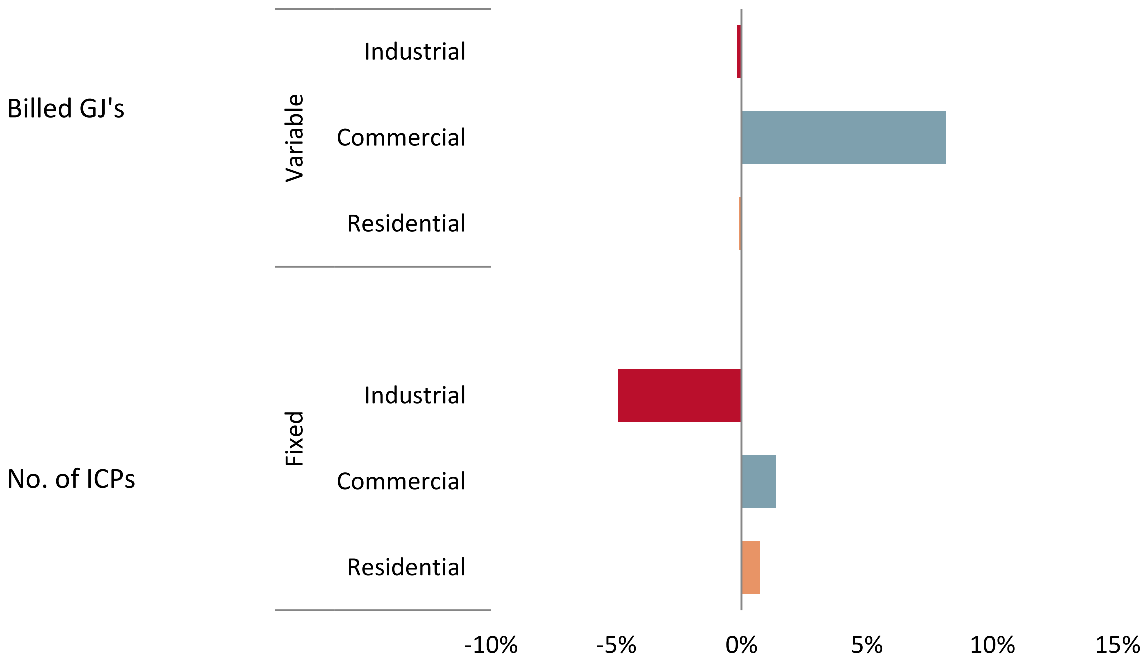


Figure 6.12 First Gas ID data – trend in 2013 – 2016 logged values



6.29 We have moved to a four-year logged trend, now that additional data for 2016 is available, and consistent with submissions suggesting that we do so.[186]

6.30 The large variances observed in the four-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

6.31 We acknowledge MGUG's submission on the policy paper that suppliers' own AMP forecasts be used in the CPRG forecasting process. We consider that this proposal, which would link expenditure forecasting with CPRG forecasting, has merit.[187]

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

Submissions on other factors we could consider in setting CPRG

6.33 Submissions on our draft CPRG method were generally supportive of our approach.[188] Most submissions focused on additional factors we could consider to refine our method.

6.33.1 Powerco suggested we should look into increases in emerging technologies like energy storage and solar photovoltaics.[189]

6.33.2 Vector suggested we should assess whether our CPRG forecasts are "achievable" given prevailing weather conditions.[190]

6.34 While we acknowledge that these factors could lead to changes in demand over the regulatory period, we have not made any changes in response to these suggestions, as a reliable means of forecasting them and factoring them into our CPRG calculations was not proposed in submissions.

[186] Powerco "Submission on the Gas DPP draft decision" (10 March 2017), para 26.
[187] MGUG "Submission on Gas DPP policy paper" (28 September 2016).
[188] Powerco "Submission on the Gas DPP draft decision" (10 March 2017), para 26.
[189] Ibid, para 24-25
[190] Vector "Submission on the Gas DPP draft decision" (10 March 2017), para 49.

Chapter 7 Setting standards for quality of service

Purpose of this chapter

7.1 This chapter:

7.1.1 sets out our 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 throughout the DPP consultation process, our view remains that reliability is the most important aspect of quality of service specifically, the avoidance of 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 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 We have used a decision-making framework that incorporated:

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 We are retaining the RTE quality standards for all gas suppliers.[191] In our view, the incentives we identified in our 2013 final decision remain relevant:[192]

> [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 and draft decision supported retaining the RTE quality standards.

7.8 Suppliers in general, have highlighted that they have the necessary systems and processes in place to report against the existing standards. However, Powerco suggested (in their submission on our policy paper) 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.[193]

7.9 We 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.

7.10 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.

7.11 The 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.

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[191] 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.

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

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

New quality standard based on major interruptions for suppliers

7.12 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.

7.13 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.

7.14 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.[194]

7.15 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 have introduced a new quality standard based on major interruptions for GTBs

7.16 We have introduced a new quality standard for GTBs. The standard will focus on major interruptions and incorporates a reporting obligation following such an event.

7.17 Submissions on our policy paper from GTBs and major users supported a quality standard relating to major interruptions for GTBs.[195] Submitters reiterated these views in response to the more detailed proposal we published in our draft decision.[196] Certain details where there were differing views are discussed below.

7.18 While interruptions in gas transmission are rare, they can have a large impact when they do occur.[197] In our view, introducing an interruptions standard is an appropriate measure to incentivise GTBs to maintain reliable gas transmission.

7.19 We discuss implementing the new quality standard for GTBs in paragraphs 7.27 to 7.65.

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

[195] 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.

[196] MGUG "Submission on Gas DPP draft reasons paper" (10 March 2017), para. 15.

[197] See: MBIE "Review of the Maui Pipeline Outage of October 2011" (October 2012), page 4. MBIE estimated the total cost of the five-day Pukearehu outage was $200 million.

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

7.20 We have not introduced a new quality standard based on major interruptions for GDBs.

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

7.21.1 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.[198] However, in Powerco's view there was no evidence that customers were dissatisfied with current service levels.

7.21.2 Similarly, Vector submitted that we should not proceed until we have clear evidence that customers are concerned with the current levels of risk management.[199]

7.21.3 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.[200]

7.22 In its submission on our policy paper, 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.[201]

7.23 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.

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198 Powerco "Submission on Gas DPP policy paper" (28 September 2016), para 122.
199 Vector "Submission on Gas DPP policy paper" (28 September 2016), para 92.
200 GasNet "Submission on Gas DPP policy paper" (28 September 2016), para 56.
201 MGUG "Submission on Gas DPP policy paper" (28 September 2016), para 34.

7.24 Historical data across the 19 years we have available shows few significant interruptions.[202] In their Gas Information Disclosure Regulation disclosures:

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

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

7.24.3 Vector did not identify any.

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

7.26 At this time, we consider that it is not necessary to introduce a major interruptions quality standard for GDBs. 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. This is because there have been few significant interruptions, and the likely smaller impact of interruptions.

Implementing the major interruptions quality standard for GTBs

7.27 The new quality standard for GTBs will focus on major interruptions, and incorporates a reporting obligation. This section sets out how we propose to implement the new standard, including:

7.27.1 specifying the quality standard that GTBs must meet;

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

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

Specifying the major interruptions quality standard

7.28 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.

7.29 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.[203]

[202] 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.

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

7.30 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.[204]

7.31 First Gas expressed support for aligning the definition of an interruption with the definition used for ID.[205] 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.[206]

7.32 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.[207]

7.33 We have linked the definition of an interruption to critical contingencies as follows:[208]

> 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.

7.34 Our reasons for this are:

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

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

7.34.3 we want to ensure any significant event that affects consumers who do not have an alternative fuel source is covered; and

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

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

205 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".

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

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

208 Critical Contingency has the same meaning as in Regulation 5 of the Gas Governance Critical Contingency Management Regulations 2008.

7.35 First Gas submitted that the major interruption quality standard should only apply to consumers above Band 2.[209] MGUG cross-submitted that this was inappropriate, as curtailments to major industrial consumers have significant commercial impacts.[210]

7.36 We agree with MGUG and it was always the policy intent that curtailments to consumers in Band 2 and above should be included in the major interruption quality standard.

7.37 We are excluding critical contingency events caused entirely by disruption upstream of the transmission system from the definition, as these are outside the GTB's control.

7.38 We are including events occurring on the network caused by third parties. While First Gas correctly points out that in many cases these will be outside its control, [211] 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.

7.39 As discussed below in paragraph 7.60.3, 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

7.40 Linked to the major interruptions quality standard, we have included 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.

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

7.41.1 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

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

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209 First Gas "Submission on the Draft reasons paper" (10 March 2017), section 4.1.

210 MGUG "Cross Submission Gas DPP 2017-Draft Reasons Paper 10 February 2017" 24 March 2017, paras 26-28

211 First Gas "Submission on the Draft reasons paper" (10 March 2017), section 4.1.1

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

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

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

7.42.3 the duration of the interruption;

7.42.4 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;

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

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

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

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

7.44.1 the CCMR is prepared by the CCO, not the GTB;

7.44.2 the focus of the CCMR is limited to the cause of the critical contingency, and the performance of the CCM system; and

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

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

7.45.1 the number of customers affected by the interruption;[212] and

7.45.2 the supplier's best estimate of the cost of the interruption to consumers.[213]

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

[213] Ibid, para 5.59.6.

7.46 First Gas submitted in response to this that the report should be limited to information that is available to it. First Gas noted that it:

7.46.1 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

7.46.2 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.

7.47 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 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

7.48 The report on the outage must be prepared within 60 working days of the end of the critical contingency, but the GTB can seek an extension to this timeframe. As signalled in our technical consultation paper, this is a change from our draft decision.

7.49 Having considered First Gas' submissions on the draft reasons paper we have decided to extend the time for the GTB to submit its report from 50 working days to 60 working days.[214] We have also decided that the 60 working days will commence from the time that the critical contingency leading to the major interruption is terminated by the CCO under CCM Regulation 60.

7.50 In our emerging view in the policy paper we initially 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.[215]

7.51 Having considered the matter further, our view was 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.

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[214] First Gas "Submission on the Draft reasons paper" (10 March 2017), section 4.1.2

[215] First Gas "Submission on Gas FPP policy paper" (28 September 2016), page 5.

7.52 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 60 working days from the end 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.

7.53 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 60 working days.

Enforcing the major interruptions quality standard

7.54 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.

7.55 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.

7.56 First Gas considered that this automatic breach for major interruptions 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 the treatment of breaches.[216] First Gas was also concerned that interruptions caused by third parties were included within the definition of the standard.[217]

7.57 Methanex was not convinced that an interruption that exceeded the limit being deemed a breach was the correct approach. Methanex suggested that the outcome of the report should determine whether a breach has occurred, and if further action is required.[218]

7.58 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.[219] 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.

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[216] Ibid, page 6.
[217] First Gas "Submission on the Draft reasons paper" (10 March 2017), section 4.1.1.
[218] Methanex "Submission on Gas DPP policy paper" (28 September 2016), para 18.
[219] MGUG "Submission on Gas DPP policy paper" (28 September 2016), para 43.

7.59 While every interruption that meets the definition set out above in paragraph 7.33 will be a breach of the quality standard, not every breach will trigger the same enforcement response.

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

7.60.1 the magnitude of the interruption;

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

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

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

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

7.60.6 the cost to the GTB of the interruption;

7.60.7 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

7.60.8 whether the GTB has previously breached the quality standards.

7.61 We consider that fault is a key consideration in deciding on any enforcement response to a failure to comply with the major interruptions quality standard.

No-action letters in response to quality standard breaches

7.62 In appropriate cases, the GTB may seek a no-action letter from us after a breach of the major interruptions standard, where we state that we do not intend to take enforcement action in response to a particular breach.

7.63 This is intended to provide comfort and some level of certainty for an applicant, on the basis that we do not foresee that we will take regulatory action in relation to their conduct.[220]

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[220] It is important to note that a no-action letter is not intended to affect the rights of third parties to take action in relation to any contravention.

7.64 If we provide such a letter to the GTB, it will still have to report that it has not complied with the major interruptions quality standard, but it will be able to state that the technical non-compliance was beyond its control, and that the Commission has accepted this view. It is likely that a GTB would apply for a no-action letter when a major interruption has been caused by a third party.

7.65 We see this option as the appropriate response to the reputational risks First Gas referred to in its submissions on the quality standard.[221]

Other drafting changes

7.66 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.

7.67 The final 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.

7.68 The final 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.

7.69 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 good industry practice (**GIP**)".

[221] First Gas "Submission on the Gas DPP Draft Decision " (10 March 2017), page 44.

Chapter 8 Assessing compliance with the price-path

Purpose of this chapter

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

8.1.1 the rules governing restructures of prices; and

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.

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-paths

8.3 GDBs and GTBs demonstrate compliance with their price-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.[222]

[222] 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 FAR.[223]

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[223] 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 our draft decision, we proposed an additional requirement that the average price increase between assessment periods must not exceed 10%. For reasons discussed in Attachment F we have removed this requirement from our final decision.

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.[224]

8.14 In our June 2016 Gas DPP implementation paper, we proposed that GTBs would have to demonstrate compliance with the revenue cap at two stages: [225]

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 the prices took effect.

8.16 PwC noted that requiring two separate compliance statements rather than one, and securing audit and certification of both, would increase costs. [226] It 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 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.

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[224] This has also been referred to as *ex ante* submission of compliance reports.

[225] Commerce Commission "Gas DPP – Implementing matters arising from the IM review draft decisions" (28 June 2016).

[226] 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.

8.18 To ensure that the DPP operates the way we intend it to, it is important that we have the necessary information to assess compliance prior to prices taking effect. This is so we can take any necessary action if forecasts are not reasonable, or if GTBs set prices in a way that will recover revenue in excess of allowable revenue.[227]

8.19 Therefore, suppliers must 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 have updated the price restructuring provisions of the GDB DPP determination 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 (a pure revenue cap), there is no need for price restructuring provisions.

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 We have adopted elements of the approach taken in the 2015 EDB DPP determination, issued on 28 November 2014.

[227] 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. The relevant changes to the GDB determination are found in clauses 8.5 to 8.8 of the determination.

8.26 In particular, we have:

8.26.1 introduced a definition of 'restructure of prices' in the GDB DPP;

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

8.26.3 provided guidance in the determination 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

8.26.4 clarified 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.[228]

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 relevant quantity information from the assessment period two years prior and any other available relevant information; and

8.34.3 use 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.

[228] 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.

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.[229]

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.[230] Powerco was generally supportive of the proposal to adopt elements of the approach taken in the 2015 EDB DPP.[231]

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.

8.39 We received no further submissions on our draft or technical consultation draft on these issues.

Treatment of transactions between suppliers

8.40 We have updated the transaction provisions for both GTBs and GDBs, providing greater certainty for suppliers about the treatment of different types of transactions, while retaining flexibility.

8.41 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, but does not contain rules setting out how transactions are to be treated.

8.42 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.

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

[229] GasNet "Submission on the Gas DPP Policy Paper" (28 September 2016), para 59.
[230] First Gas "Submission on the Gas DPP Policy Paper" (28 September 2016), page 7.
[231] Powerco "Submission on the Gas DPP Policy Paper" (28 September 2016), paras 143 to 145.

Table 8.1 Types of transactions under the DPP

Transaction type	Definition	Covered in	Treatment
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 GDBs combine completely by any other method	DPP Clause 10	As for amalgamations
Transfers (GDBs only)	GDB acquires or disposes of assets used in supplying consumers	DPP Clause 10 Schedule 6	Three alternatives: 1) GDBss agree transfer of ANR 2) GDBs 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

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

8.44.1 '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;

8.44.2 'mergers', where two GDBs combine to form a single economic entity by means other than an amalgamation; and

8.44.3 'transfers', where a GDB transfers some, but not all of its assets used to provide gas distribution services to consumers, to another person.[232]

[232] A transfer covers situations where a GDB transfers assets (and consumers) to another GDB, or a GDB transfers assets (and consumers) to a non-GDB, but does not cover the situation where a GDB acquires assets (and consumers) from a non-GDB.

Amalgamations

8.45 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.[233] The GDB DPP determination sets out how this applies in practice,[234] and includes a requirement for the GDBs to notify the Commission of the amalgamation.[235]

Mergers

8.46 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.[236] As such, the DPP determination requires GDBs to treat such a transaction the same as an amalgamation.

Transfers

8.47 GDBs may also engage in transactions where they dispose of or acquire assets used to supply consumers with gas distribution services, but where they 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.

8.48 As such, we are proposing an approach to these ‘transfers’ which provides for four options for GDBs to adjust their ANR:

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

8.48.2 in the second instance, where a GDB acquiring consumers is unable to agree an allocation with the other GDB party to the transaction, it applies the formula in paragraph 4 of Schedule 6 of the DPP determination to derive an allocation of ANR;

8.48.3 in the third instance, where a GDB transferring consumers is unable to agree an allocation with the other GDB party to the transaction, or the other party to the transfer is not a GDB, it applies the formula in paragraph 5 of Schedule 6 of the DPP determination to derive an allocation of ANR; and

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233 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.
234 Gas Distribution Services Default Price-Quality Path Draft Determination 2017, clause 10.
235 Gas Distribution Services Default Price-Quality Path Draft Determination 2017, clause 10.3.
236 Control in this situation means the acquisition of rights similar to ownership, such as a long-term lease.

8.48.4 finally, where a GDB cannot agree an allocation with the other GDB party to the transaction, or where the formulae in Schedule 6 do not work, or the application of the formulae would be inconsistent with the purpose of Schedule 6, a GDB may apply to the Commission to use an alternative methodology.

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

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

The transactions in the gas sector have highlighted areas for improvement

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

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

8.52.1 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;

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

8.52.3 requiring greater disclosure around the allocation of ANR or allowable revenue (**AR**) in situations of a partial network sale or purchase; and

8.52.4 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.

8.53 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.[237]

[237] Vector “Submission on the Gas DPP Policy Paper” (28 September 2016), para 96.

8.54 Our general approach in making our 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.

8.55 We also aim to ensure that:

8.55.1 compliance requirements are clear;

8.55.2 that no unintended price-quality path breaches occur simply as a result of an acquisition or divestment;

8.55.3 and that the costs of compliance are reasonable in the circumstances.

Notification provisions for transactions

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

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

Transaction provisions for GTBs

8.58 In the GTB determination, we are removing the detailed rules related to transactions, but have included a notification requirement for any kind of transaction (amalgamation, merger, or transfer) and the newly defined 'major transactions'.

8.59 As noted previously, we have not including any rules relating to the treatment of transactions for GTBs. 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 with prescriptions in a DPP determination. As such, the reopener provisions in the IMs are the appropriate way of dealing with transactions involving GTBs.

Treatment of 'major' transactions

8.60 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.[238]

8.61 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.

[238] 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.

Attachment A Key steps in the DPP process

A1 Table A1 below sets out the key steps in the DPP setting process

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
20 December 2016	Final decision on the IM review
10 February 2017	Draft decision
10 March 2017	Submissions on draft decision
23 March 2017	Updated draft decision on Gilbert Stream
24 March 2017	Cross-submissions on draft decision
31 March 2017	Further cross-submission on draft expenditure decisions
13 April 2017	Technical consultation on determination drafting
28 April 2017	Submissions on technical consultation
31 May 2017	Final decision

Attachment B Impact of the input methodologies review

Purpose

B1 This attachment sets out the IM decisions affecting GPBs that we changed as part of the recent IM review.[239]

IMs 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 Report on the IM Review.[240]

B4 The changes to the IMs are given effect through the IM amendments determinations.[241] 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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239 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.

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

241 *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 (**TCSD**) 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

Decision	Short title (amended if applicable)	Impact on the DPP
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

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
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
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
IR08	Incremental rolling incentive scheme (**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

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.[242] 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.[243] 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.[244] 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.[245] 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.

[242] 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).
[243] Commerce Commission "Gas DPP Reset 2017—Summary of question and answer session 14 September 2016" (22 September 2016).
[244] 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.
[245] 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).

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 the likely changes to our expenditure forecasting approach, as well as provide interim clarification before the February draft decision reasons paper.[246]

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 BAU 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.[247]

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[246] Commerce Commission “Gas default price-quality path reset 2017—Current views on forecasting expenditure” (31 October 2016).

[247] GasNet “Submission on Gas DPP policy paper” (28 September 2016) para 9.

C11 Vector and Powerco raised similar concerns about the perceived increased cost of our proposal.[248]

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 clarifications we have made, we are satisfied that the process is well below the cost of a CPP.[249]

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;[250]

C13.2 the types of evidence we would seek as part of supplier scrutiny;[251] 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.[252]

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.

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[248] 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.

[249] The only electricity distributor or gas pipeline to apply for a CPP so far has been Orion. Orion's CPP cost approximately $5 million, 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.

[250] 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" (28 September 2016), para 22 and 30.

[251] 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.

[252] Orion "Submission on Gas DPP policy paper" (28 September 2016), para 29.7; First Gas "Submission on Gas DPP policy paper" (28 September 2016), page 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.

C16 GasNet submitted that:

> 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).[253]

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.[254] 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”.[255]

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.

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[253] GasNet “Submission on Gas Pipeline Services 2017 DPP policy paper” (28 September 2016) para 32.

[254] 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.

[255] 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.

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 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.[256]

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. In the draft decision we 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.

[256] 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.

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.[257] 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.[258]

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 unrealistic.[259] 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.

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257 ENA "Default price-quality paths for gas pipeline services from 1 October 2017—Submission to the Commerce Commission" (28 September 2016) para 18.

258 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.

259 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.

C29 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. Further information provided between the draft and final decisions has been published on our website, or is available in supplier's submissions.

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.

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.[260] GasNet stated that "the Commission appears to be interpreting data in a particular way when other plausible interpretations are available".[261]

[260] 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.

[261] GasNet "Submission on Gas Pipeline Services 2017 DPP policy paper" (28 September 2016) para 71.

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.[262]

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 intended 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;[263]

C37.2 expenditure per TJ;[264]

C37.3 cost of interruptions;[265]

C37.4 revenue per TJ and revenue per ICP;[266] and

C37.5 capex and opex variation per ICP and per total gas supplied.[266]

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[262] 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.

[263] 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.

[264] 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.

[265] 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.

[266] 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.

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: [267]

> 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.

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[267] MGUG "Gas DPP reset 2017-Policy for setting price paths and quality standards for gas pipeline services" (28 September 2016) paras 13–14.

C41 Some submitters suggest extending the metric and ratio approach to benchmark GPBs against each other. However, Powerco disagrees with MGUG that benchmarking should be used to create downward price pressure on GPBs.[268] We are unable to take into account comparative benchmarking analysis when we set prices in the DPP.[269]

[268] 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.

[269] Section 53P(10) of the Commerce Act.

Attachment D Expenditure forecasts

Purpose

D1 This attachment shows our expenditure forecasts for the 2017 DPP, based on our assessment of suppliers' forecasts by area of expenditure.[270]

Table D1 Our forecast capex for the proposed regulatory period ($000, 2016)

Capex category	First Gas trans.	GasNet	Powerco	Vector	First Gas dist.	Total
Asset relocation	$1,791	$98	$84	$627	$708	$3,308
Asset replacement and renewal	$92,011	$2,032	$13,950	$7,639	$18,166	$133,797
Consumer connections	$7,880	$525	$16,888	$63,322	$11,996	$100,611
Non-network assets	$17,644	$531	$5,708	$6,400	$2,083	$32,367
System growth	$0	$513	$8,333	$5,618	$16,576	$31,039
Reliability, safety, and environment	$15,459	$406	$21,606	$1,894	$0	$39,366
Cost of financing	$3,828	$0	$220	$436	$416	$4,900
Capex total	$138,613	$4,104	$66,788	$85,936	$49,946	$345,388

[270] The draft decision version of this table incorrectly displayed the figures for First Gas transmission. Opex figures were based on combining Maui and First Gas Distribution values, not Maui and Kapuni values. This error only affected the way this table was presented, and not our calculation of starting prices.

Table D2 Our forecast opex for the proposed regulatory period ($000, 2016)

Opex category	First Gas trans.	GasNet	Powerco	Vector	First Gas dist.	Total
Asset replacement and renewal	$0	$0	$15,044	$0	$0	$15,044
Business support	$61,177	$3,825	$33,369	$21,701	$8,236	$128,308
Routine and corrective maintenance and inspection	$85,536	$425	$10,336	$12,308	$9,227	$117,832
Service interruptions, incidents and emergencies	$3,262	$300	$2,073	$9,785	$11,353	$26,773
System operations and network support[271]	$36,449	$3,400	$20,681	$12,573	$6,489	$79,592
Compressor fuel	$22,002	n/a	n/a	n/a	n/a	$22,002
Land management and other activities	$3,751	n/a	n/a	n/a	n/a	$3,751
Opex total	$212,177	$7,950	$81,503	$56,367	$35,305	$393,301

[271] GTBs disclose 'System Operations' and 'Network Support' opex as separate categories. These categories have been combined in this table.

Attachment E Economies of scale

Purpose

E1 This attachment:

E1.1 describes how we considered efficiency gains and losses from changes in economies of scale that resulted from recent industry transactions;[272]

E1.2 sets out how we have identified gains or losses from changes in scale for the different transactions; and

E1.3 describes how we have adjusted our expenditure forecasts for lost economies of scale.

E2 As in our draft decision, we have identified losses in economies of scale for Vector distribution, but not for other suppliers. However, in response to submissions on the draft decision, we have changed how we adjusted our forecasts to account for these losses.

How we have considered changes in scale

E3 Consistent with our draft decision, we consider that it is reasonable for suppliers to enjoy the benefits or bear the costs of any gains or losses in economies of scale for a period of time

E4 However, in response to submissions on our draft decision, we have changed the period of time over which any gains or losses are shared from an effective six and a half year period to a five-year period.

Our approach to economies of scale in the draft decision

E5 For the draft decision, we said that consistent with the 2010 IM reasons paper, suppliers should be 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.[273]

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[272] 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. Additionally, in early 2017 GasNet sold distribution assets in the Papamoa area to First Gas.

[273] Commerce Commission "Input methodologies (electricity distribution and gas pipeline services) reasons paper" (22 December 2010), para 3.3.28.

E6 We proposed that the suppliers should temporarily retain any costs of 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.

Stakeholder submissions on our draft decision

E7 Vector submitted that our proposed treatment of gains and losses in economies of scale resulting from the transaction represented a departure from the approach set out in the 2010 IM Reasons Paper in relation to mergers and acquisitions. [274]

E8 According to Vector, the 2010 IM reasons paper set out that any benefit resulting from an acquisition would occur for the remaining duration of the DPP or CPP, at which point the Commission would reset prices to ensure that any benefit was shared with consumers.[275] Vector submitted that the proposal in the 2017 GPB draft reasons paper would defer such sharing for a further five years.[276]

E9 In its submission on behalf of Vector, CEG also argues that the proposed treatment of economies of scale in the 2017 draft Gas DPP is inconsistent with the IMs. According to CEG, the parties to the transaction would have negotiated on the expectation that any change in economies of scale would only be adjusted for during the regulatory period in which the transaction occurs. [277]

> Such a change in policy has a very large impact. Under the 2010 IM, Vector would only bear the loss of economies of scale for approximately 1.5 years, from the time when the transaction occurred in April 2016 until the beginning of the new DPP in October 2017. Similarly, FGL would receive the gains from economies of scale for the same timeframe of 1.5 years. Consequently, the two parties' negotiated sale price would rationally have reflected compensation to Vector for its loss of economies of scale for only 1.5 years, as well as an additional charge to FGL for its 1.5 years of surplus from the gains in economies of scale arising out of the combined MDL and Vector transmission businesses.
>
> Under the 2017 Draft Reasons Paper, however, Vector is now, after the fact, required to bear the loss of economies of scale for 6.5 years until the end of the 2017-2022 regulatory period, while FGL would also receive the benefits of economies of scale for 6.5 years. Even if the 2017 policy is symmetrical (which the Commission claims but which is unclear to us), this involves a very large after the fact transfer of wealth.

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[274] Vector "Submission to the Commerce Commission on the Default Price Quality Paths for Gas Pipeline Businesses Draft Reasons Paper" (10 March 2017) para 31.
[275] Ibid, para 32.
[276] Ibid, para 33.
[277] CEG "Treatment of changes in economies of scale due to transactions", (10 March 2017) paras 30-31.

E10 In commenting on the impact of the approach to economies of scale that we proposed in the draft reasons paper, First Gas stated in its cross-submission that:[278]

> The size of the adjustments proposed by the Commission are too small to materially affect a vendor's view of the economics of an asset sale. The Commission has proposed adjustments of $1.6 million to opex and $0.6 million to capex over the five year period, compared with a sale price received by Vector for its gas pipelines of $952 million.

Response to submissions

E11 Since the original IMs were determined in 2010, there have been a number of important developments in the implementation of price-quality regulation which have a bearing on the treatment of efficiency gains and losses and the period over which these effects should be taken into account.

E12 First, the introduction of the IRIS for EDBs allows suppliers to retain efficiency gains beyond the end of the current regulatory period. Although GPBs are not subject to an IRIS, the approach that we proposed in the draft had a similar effect in terms of allowing GPBs to retain any gain on economies of scale (or bear any loss of economies of scale) resulting from a merger or acquisition for a period beyond the end of the current regulatory period.

E13 In addition, the use of a building block approach to reset prices (as opposed to the 'banded' approach to resetting DPPs that was contemplated when we determined the IMs in 2010) ensures that in resetting prices, we are able to more explicitly take account of any efficiency gains and losses that are identified as a result of transactions such as the Vector-First Gas transaction.

E14 For these reasons, we consider that the approach we proposed in the 2017 draft Gas DPP is appropriate, and aligned with the policy intent expressed in the 2010 IMs of allowing regulated suppliers to retain benefits and bear losses from identifiable changes in economies of scale that result from a merger or acquisition for a period of time, rather than be shared with consumers immediately.

E15 However, for the purposes of the Final DPP Reset, we have assessed the effect of changes in economies of scale over a period of five years from the time of the transaction. This timeframe aligns with the retention period used in the case of the IRIS framework. Given the date of the transaction, this has involved an adjustment to those expenditure categories where a change in economies of scale has been identified, running effectively until April 2021.

[278] First Gas "Cross-submission default price-quality paths for gas pipeline businesses from 1 October 2017 to 30 September 2022, Draft reasons paper" (24 March 2017) page 7.

How we have identified gains or losses in scale

E16 This section discusses how we have identified:

E16.1 potential losses in economies of scale due to the Vector-First Gas distribution transaction;

E16.2 potential gains or losses in economies of scale due to the Papamoa transaction between GasNet and First Gas distribution; and

E16.3 potential gains in economies of scale due to the Vector-MDL-First Gas transmission transaction.

Vector and First Gas distribution

Network opex

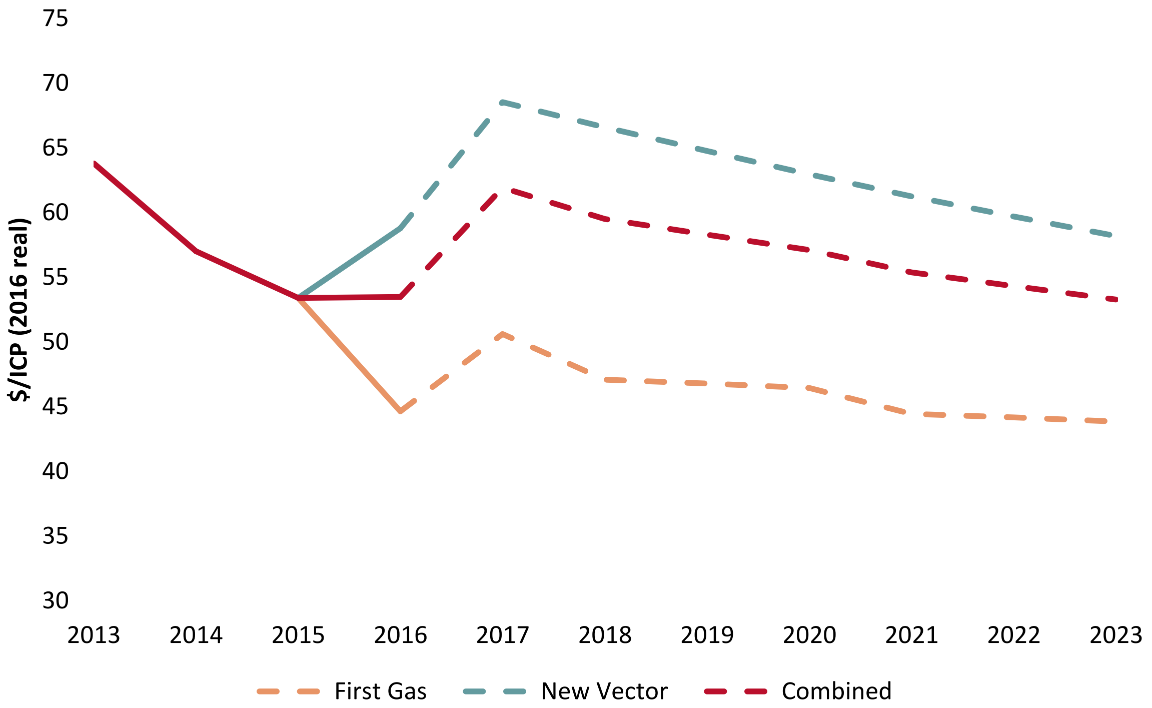
E17 We have not identified any losses in economies of scale for network opex. Total network opex across the First Gas and Vector distribution networks as forecast by the suppliers is similar during the proposed regulatory period to what it was before part of the network was sold to First Gas.

E18 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. As such, we have made no adjustments to network opex.

Non-network opex

E19 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 consider that this is evidence of an efficiency loss caused by reduced economies of scale.

Figure E1 Vector non-network opex/ICP



E20 We also considered the changes in non-network opex by each of the two relevant suppliers. We did this by comparing non-network opex per ICP before and after the transaction. As can be seen in Figure E1 for combined Vector and First Gas non-network opex between 2015 and 2017, there is an appreciable and persistent increase in per ICP opex.[279]

E21 It is clear from this analysis that this increase is caused by a one-off step-change in Vector's non-network opex, rather than an increase in both suppliers' opex or a temporary transitional increase.

[279] The decline from 2017 onwards is due to flat non-network opex in real terms, combined with continued ICP growth for both suppliers.

E22 High levels of non-network opex in these situations could be caused by higher supplier forecast relative to historic levels, rather than due to a loss of scale. However, Vector distribution also stated in its latest AMP that: [280]

> 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.

E23 This approach differs from our analysis at the draft decision, where we made use of our 'backcast' split in the historic expenditure of the original Vector distribution business into the two new networks using the expenditure proportions forecast by the two suppliers for 2016.[281]

E24 In response to our draft decision, Vector submitted that these backcast data relied too much on the Commission's judgement, rather than on supplier's audited filings.[282] Our analysis for the final decision makes use only of data provided by Vector and First Gas, and still clearly demonstrates a loss of economies of scale for Vector's non-network opex.

E25 The adjustment we have made as a result of these identified losses in economies of scale are discussed below in paragraphs E36 to E39.

Expenditure on non-network assets

E26 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.[283]

E27 This is a clearly identified impact of the reduced economies of scale. As discussed in Chapter 5, this has formed part of our reasoning for not accepting Vector's expenditure on non-network assets forecasts. However, we have made no additional adjustments for expenditure in this category.

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280 Vector "Gas Distribution Asset Management Plan 2016 – 2026" (August 2016) section 1, page 7.

281 The expenditure proportions were calculated from the responses to our 53ZD request for information from gas pipeline service suppliers, which were published alongside or draft reasons paper. The updated backcasting method is discussed in Chapter 4.

282 Vector "Submission GPB DPP Draft Reasons Paper" (10 March 2017) para 12.

283 Vector "Gas Distribution Asset Management Plan 2016 – 2026" (August 2016) section 9, page 6.

Bay of Plenty asset sale

E28 We have not 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.

Transmission

E29 We have not identified any clear efficiency gain by First Gas resulting from the merger of the transmission businesses previously owned by Vector and MDL. 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:

E29.1 non-network;

E29.2 services, interruptions, incidents and emergencies;

E29.3 routine and corrective maintenance and inspection; and

E29.4 asset replacement and renewal.

E30 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.

E31 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.

E32 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.

E33 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 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.

E34 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 seven to nine years after the previous AMPs were written.

E35 We do not see any clear indication of an efficiency gain from the merger being included in the forecast expenditure.

Adjustment for losses in economies of scale

We have set Vector's non-network opex based on historic economies of scale

E36 To implement the approach we discussed above in paragraphs E11 to E25, we have set Vector's non-network opex based on preserving its historic economies of scale for the first three and a half years of the 2017-2022 regulatory period.

E37 We have calculated this 'scale' forecast by:

E37.1 taking the 2013-2015 average per ICP non-network opex for Vector's pre-sale GDB business; and

E37.2 multiplying this by Vector's AMP forecasts of ICP growth for the 2017 regulatory period.

E38 We then take the difference between the 'scale' forecast and Vector's AMP forecasts to create an 'adjustment' which is applied in our expenditure model. This adjustment has been applied whole in the first three years of the period. In the fourth year of the period, we have deducted half the amount.

E39 The amounts we have deducted in each year of the regulatory period are set out in

Table E1 Adjustments for economies of scale – Vector non-network opex ($000, 2016)

Year ending June 30	2017	2018	2019	2020	2021	2022
Adjustment	$0	-$993	-$812	-$626	-$329	$0

Attachment F Price setting and wash-up processes for the pure revenue cap

Purpose

F1 This attachment sets out our decisions relating to the price setting and wash-up processes to be applied by GTBs.

Structure

F2 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 decisions on the price setting and the wash-up processes under the following sections:

F2.1 **Process sequence and timing:** In this section we set out the sequence and timing of the price setting and compliance assessment process and the wash-up calculations.

F2.2 **Price setting process and assessing compliance:** In this section we outline the price setting process and how compliance is assessed against the DPP determination. The flowchart presented in Figure F1 at the end of this attachment also sets out this process.

F2.3 **Wash-up calculation:** In this section we outline how the wash-up is calculated and how the relevant inputs to the calculation are determined. The flowchart presented in Figure F2 at the end of this attachment also sets out this process. For demonstration purposes, we have also prepared a form of control model on how the wash-up mechanism would work in practice.[284]

Background

Purpose of the wash-up mechanism

F3 The IMs 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. The purpose of the wash-up is to ensure that revenue is not under or over-recovered over time.

[284] Commerce Commission "Form of control demonstration model" available at: http://comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

Summary of decisions

F4 The GTB IMs set 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 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 not to specify such an annual maximum 'average price increase limit'. This is a change from our draft decision, and is discussed in paragraphs F21 to F28.

F4.2 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. This is discussed in paragraphs F47 to F51.

Process sequence and timing

F5 In this section we set out the sequence and timing of the price setting and compliance assessment process and the wash-up calculations by going through the process steps that must occur in each of the five assessment periods of the next regulatory period.

F6 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

F7 Only the price setting and compliance assessment process will be performed when setting prices for the first and second assessment periods of the next regulatory period. This is because, as outlined below in the process steps that must be followed for the third and subsequent assessment periods, setting prices and taking into account any amounts to be washed up requires two prior assessment periods.

Third and subsequent assessment periods of the regulatory period

F8 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. Three consecutive assessment periods will feature in each of these wash-up calculations. For this attachment we define names for each of these three assessment periods as follows:

F8.1 the 'assessment period to be washed up', will be the earliest of these three assessment periods;

F8.2 the 'calculation assessment period', will be the second of these three assessment periods;[285] and

F8.3 the 'assessment period for which prices are to be set', will be the last of these three assessment periods.

F9 The table below shows the three consecutive assessment periods. For the calculation assessment period it shows that this assessment period comprises four phases:

F9.1 waiting for data from the prior assessment period (such as quantities supplied) to become available;

F9.2 doing the wash-up calculation;

F9.3 with the results of the wash-up calculation available, setting prices for the subsequent assessment period; and

F9.4 the notice period for prices, being from the time that finalised prices are published to the time they take effect.

Table F1 Process timeline

Third and subsequent assessment period of the next regulatory period					
Assessment period to be washed up	**Calculation assessment period**				**Assessment period for which prices are to be set**
	Phase 1 Waiting for data from prior assessment period	**Phase 2** Wash-up of prior assessment period	**Phase 3** Price setting for forthcoming assessment period	**Phase 4** Notice period for prices	

[285] Prices are calculated, set, and notified by the GTB in advance of the assessment period in which those prices apply.

F10 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.

F11 A few months into the calculation assessment period, the necessary information for the GTB to perform the wash-up calculation will be available. This information would include:

F11.1 actual quantities of services provided in the assessment period to be washed up;

F11.2 prices;

F11.3 actual pass-through and recoverable costs;

F11.4 actual CPI values for the calculation of actual net allowable revenue; and

F11.5 other regulated income received.

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

F12.5 determining the 'revenue account draw-down amount', see paragraphs F28 to F32.

Price setting process and assessing compliance

F13 In this section we outline the price setting process and how compliance is assessed against the DPP determination.

Assessing compliance with the DPP Determination

F14 Compliance with the DPP determination requires forecast allowable revenue (including the recovery of forecast pass-through and recoverable costs) to be calculated, and a set of prices to be developed such that the forecast revenue from prices does not exceed the forecast allowable revenue.

Price setting process

Forecast allowable revenue

F15 The forecast allowable revenue must be the sum of:

F15.1 the forecast net allowable revenue;

F15.2 the forecast of the pass-through and recoverable costs (excluding any revenue account draw-down amount); and

F15.3 the opening balance of the wash-up account (this equals the revenue account draw-down amount, see paragraph F29).[286]

F16 We have calculated the forecast net allowable revenue for each assessment period of the regulatory period in the financial model, so these values are now available.[287] Each of the five values is listed in Schedule 2 of the DPP determination. [288]

F17 The GTB will prepare a forecast of the pass-through and recoverable costs during each price setting process. These forecasts will exclude a revenue account draw-down amount (which will itself be a recoverable cost).

F18 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.

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[286] 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.

[287] 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.

[288] For clarification, we note that the forecast net allowable revenue is referred to in the financial model as the maximum allowable revenue before tax, or MAR.

F19 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)).

Forecast revenue from prices

F20 The GTB will prepare a schedule of prices and forecast quantities. From these the GTB will calculate the forecast revenue from prices as the total of each price multiplied by its corresponding forecast quantity.

Removal of the limit on the increase in average prices

F21 As signalled in our technical consultation paper, we have not included a limit on the increase in average prices in the final GTB determination. The GTB IMs give us the option of adopting or not adopting the average price increase limit.[289]

F22 Our draft decision included a limit on the increase in average prices, set at 10% in real terms. The draft method for calculating the increase relied on the concept of a 'revenue class'.

F23 We consider that the revenue class approach would not be workable, given the likely range of forthcoming changes to the Gas Transmission Access Codes. First Gas stated:[290]

> One immediate challenge is that none of the proposed new price categories are the same as the price categories that currently exist under the VTC and the Maui Pipeline Operating Code (MPOC).

F24 If there are no common price categories between the two assessment periods, then the calculation method is likely to fail. If the lack of any common price categories means that there will be no common revenue classes, the average price increase will always be negative 100%, regardless of how high the prices are for the second of the two assessment periods.

F25 Even if one common revenue class could be identified in the final Gas Transmission Access Code that is eventually adopted, it is not clear that the calculated average price increase would be a reasonable measure, given the new price categories that First Gas has proposed.

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[289] *Gas Transmission Services Input Methodologies Amendments Determination* 2016 [2016] NZCC 26, clause 3.1.1(2).

[290] First Gas "Submission on the Gas DPP Draft Decision" (10 March 2017), page 6. "Revenue class" (in our determination) effectively equals "price categories" (in First Gas' submission).

F26 First Gas' proposed pricing approach was in its Feb 2017 paper "Gas transmission access code development: Proposed decisions and next steps", which was released via the GIC website a few days after our draft decision. It confirms First Gas' submission that there will be no common price categories between the current and proposed pricing structures.

F27 Our decision not to limit the increase in average prices will not result in any long-term wealth transfer between the GTB and consumers, relative to the draft decision approach. The average price increase limit mechanism in the draft decision would only smooth cash-flows. The draft decision approach effectively allowed the supplier to recover, over time, the impact of any limit in present value terms.

Revenue wash-up draw-down amount

F28 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.

F29 For calculating the actual allowable revenue and for calculating the closing wash-up account balance, we have set the revenue account draw-down amount 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.

F30 However, 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.

F31 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.

F32 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

F33 In this section we outline how the wash-up is calculated and how the relevant inputs to the calculation are determined.

Wash-up amount

F34 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 F47 to F51).

F35 The difference between the actual allowable revenue and the actual revenue reflects to what extent a GTB has under or over-recovered. Whether the difference is added to, or subtracted from, the wash-up account depends on whether the difference is a positive or negative amount.

F36 An amount of 'revenue foregone' may be subtracted from the difference to be applied to the wash-up account if the cap on the wash-up amount (as specified in the GTB IM) binds.[291]

F37 More details on calculating the revenue foregone are set out in the 'Cap on the wash-up amount' section below.

Actual net allowable revenue

F38 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

F39 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

F40 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.

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

F41 The actual allowable revenue for the first assessment period of the regulatory period commencing 1 October 2017 (new regulatory period) may include an amount to recover pass-through and recoverable costs from the regulatory period ending 30 September 2017 (current regulatory period) that has not been recovered during the current regulatory period.

F42 The recovery of these pass-through and recoverable costs will include multiple time value of money adjustments. The first will be for the year between the last assessment period of the current regulatory period and the first assessment period of the new regulatory period. Further time value of money adjustments will in effect apply as part of the wash-up process for the new regulatory period. These will be determined at the discount rate specified for this process.

F43 The first adjustment will be at a discount rate of 5.38%. This rate is the discount rate specified in the Schedule 6 of the DPP for the current regulatory period for time value of money adjustments in relation to pass-through and recoverable costs.

F44 In its submission on the technical consultation paper, First Gas queried why we would apply the discount rate from the current regulatory period, rather than the discount rate for the new regulatory period.

F45 We have chosen to continue to apply the 2013 DPP discount rate because this adjustment essentially applies until the first year of the new regulatory period, The standard time value of money discount rate for the new period then applies to the adjustments during the new period.

F46 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

F47 As discussed in paragraphs F8 to F10, 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.

F48 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.

F49 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 money adjustment as set out below.

F50 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.

F51 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

F52 As set out in the IMs, there is a cap on the wash-up amount.[292] 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. The implementation of this cap is through 'revenue foregone', which is the amount of permanent loss the GTB will incur if the cap binds.

F53 Calculating revenue foregone requires another parameter to be defined and determined: the 'revenue reduction percentage'. This reflects the extent to which actual revenue from prices are less than forecast revenue from prices. It is, in turn, the average reduction in quantities between forecast and actual values, using the prices as weights in the weighted average calculation.

F54 The formula for revenue reduction percentage is:

> Revenue reduction percentage = 1 - (actual revenue from prices ÷ forecast revenue from prices)

F55 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%.

F56 In this formula, the actual net allowable revenue is the value for the assessment period being washed up.

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[292] Commerce Commission "Input methodologies review – Topic paper 1" (20 December 2016), page 34.

F57 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

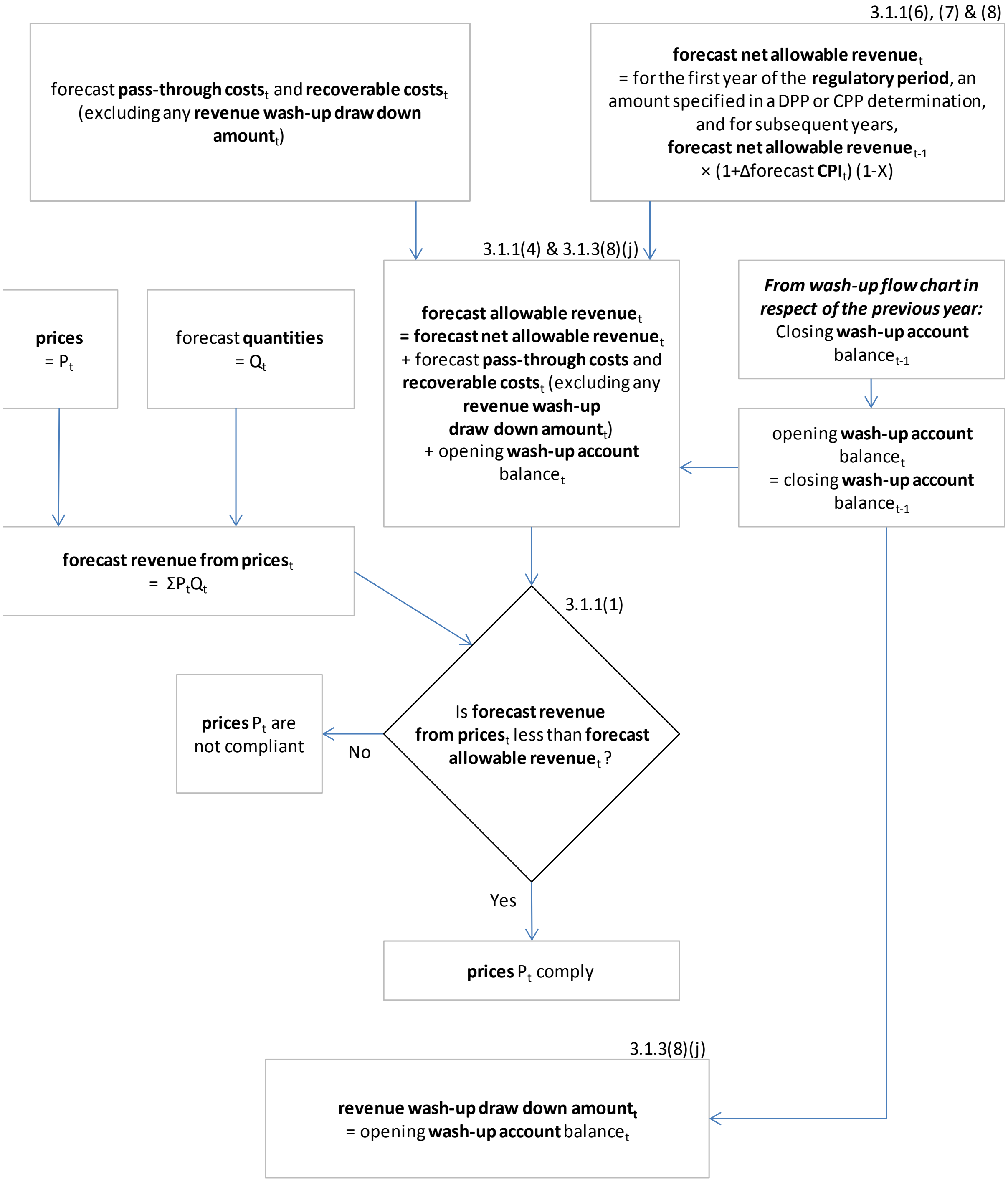
F58 We have designed the implementation of the IMs to make sure that the cap on the wash-up amount does not prevent pass-through and recoverable costs from being fully passed through and fully recovered.[293]

F59 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. This model is available on our website at.[294]

[293] Commerce Commission "Input methodologies review – Topic paper 1" (20 December 2016), para 156.
[294] Available at http://comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

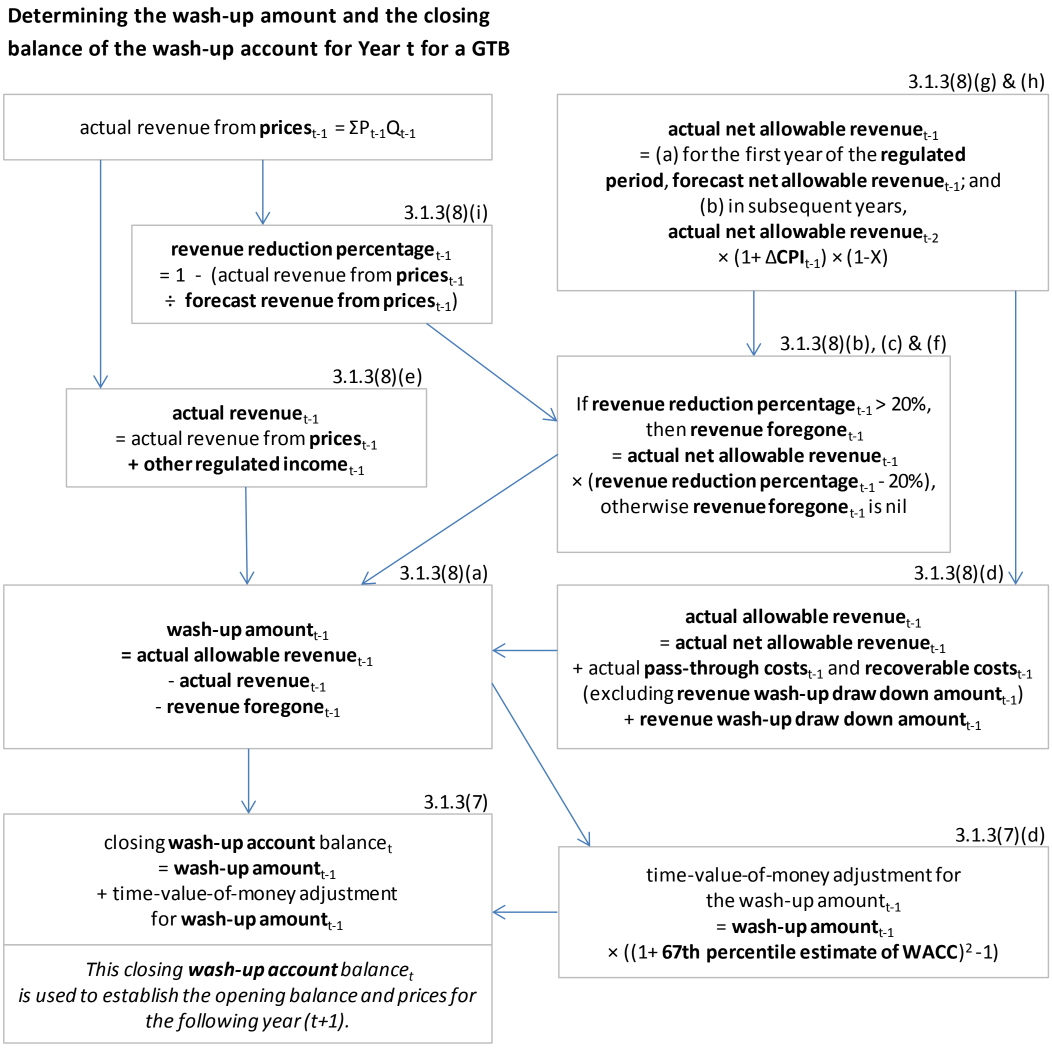
Figure F1 Setting prices and assessing compliance for Year-t

Setting prices and assessing compliance for Year t for a GTB



* The opening **wash-up account** balance for Year t is the total amount in the **wash-up account** available to be drawn down in setting prices for the pricing year t.

Figure F2 Determining the wash-up amount and the closing wash-up account balance



F60 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.

F61 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.

F62 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

F63 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 determination.

F64 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 F45.

F65 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:

G1.1 the data we used in the financial model.

G1.2 the data that we use to set our projections of data that are inputs to the financial model, including; opex, capex, CPRG, other regulated income, and disposals data; and

G1.3 estimations and adjustments we have made for financial modelling and supplier forecasting purposes.

Overview of data used in the financial model

G2 The data inputs to the financial model fall into four categories:

G2.1 inputs that are not supplier-specific, such as WACC and CPI;

G2.2 data based on supplier-specific information from AMP;

G2.3 data based on supplier-specific information from ID Schedules 1 to 10; and

G2.4 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

G3 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.

G4 To correct for this we have reflated expenditure forecasts in our expenditure model.[295] Opex forecasts are reflated using a combination of the Labour Cost Index (**LCI**) and the Produce Price Index (**PPI**) in a 60:40 ratio. Capex is reflated using only the PPI. Both of these indices were obtained from NZIER.

[295] Commerce Commission "Expenditure model". For the draft decision, these calculations were performed in a separate "Expenditure reflation model".

G5 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.[296]

Reflation adjustments for First Gas

G6 The September 2016 year-end for First Gas' AMP has affected how we reflate First Gas' opex and capex forecasts.

G7 The adjustment in the first year of the reflation series needs to account for less than a full year's inflation in the LCI and PPI series.

G7.1 For the Maui transmission network, the reflation calculation adjusts from September 2016 to December 2016 prices (one quarter of inflation).

G7.2 For the Kapuni transmission network and for First Gas distribution, the reflation calculation adjusts from September 2016 prices to June 2017 prices (three quarters of inflation).

G8 This is a change from our draft decision.

CPRG

G9 CPRG forecasts incorporate the growth in both the variable charge component (quantity of gas billed) and fixed charge component (number of ICP connections).

G10 To estimate the variable charge component we use supplier ID information to gain a historical view of the trend in our CPRG model.[297] We also used an independent study from Concept Consulting on behalf of the GIC.[298] A technical review of this study, commissioned by the Commerce Commission, was published alongside our policy paper on 30 August 2016.

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[296] 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.

[297] Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015) NZCC7, available at http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-information-disclosure/.

[298] 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/.

Consumer Price Index

G11 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.[299] The inputs to this model are the historical quarterly CPI data from Statistics New Zealand[300] and quarterly CPI forecasts from the Reserve Bank of New Zealand.[301]

G12 We have updated the CPI inputs used to those available when the WACC for the DPP was determined (1 March 2017).

G13 In submissions on our policy paper and draft decision, Vector questioned our method for forecasting CPI.[302]

G14 Vector submitted that it had "serious reservations about the inflation forecasts being considered for the DPP." Vector recommended "the Commission to consider the reasonableness of its inflation forecasts given the extended history of low actual inflation since the start of the decade."

G15 In the First Gas cross-submission on the draft decision, First Gas shared Vector's concerns with CPI forecasting.[303] It submitted that, while it appreciates that we is constrained by the IMs, it recommended we consider any pragmatic solutions available.

G16 As the calculation of CPI is determined by the IMs, we are not able to address this in the DPP. We do not consider there are "pragmatic solutions", as the IMs are prescriptive. Our response to Vector's and First Gas' concerns can be found in Topic Paper 1 for the final decision for the IM review.[304]

G17 We note that we have taken the same approach to extending the LCI and PPI inflation series we use to reflate expenditure forecasts beyond the end of the forecasts available from NZIER.

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[299] 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/.

[300] 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.

[301] 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.

[302] Vector "Submission on the Gas DPP draft decision" (10 Mar 2017).

[303] First Gas "Cross-submission on the Gas DPP draft decision" (24 March 2017).

[304] Commerce Commission "Input methodologies review – Topic paper 1" (20 December 2016), pages 56-69.

G18 While this does not act as a 'hedge' against the CPI forecasting concerns raised by submitters, there is a partial offset (an over-forecast of CPI in the financial model results in lower starting prices, an over-forecast of LCI/PPI results in higher starting prices).

Disaggregated data for previous Vector distribution network

G19 The former Vector gas distribution network has been split into two networks, one of which was sold to First Gas and the other retained by Vector.

G20 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.

G21 The data requirements were met through a combination of the suppliers' 2016 ID disclosures and their response to the 53ZD request received in August 2016.

G22 For supplier forecasting analysis we created 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. We called this backcasting in our expenditure model.

G23 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 in the supplier forecast analysis.

G24 For the final decision we amended the backcasting calculation approach after receiving 2016 actual expenditure data and also in response to the Vector submission[305] which stated that the draft decision backcasting approach was not transparent.

G25 The backcasting method used for the final decision contains the 2016 expenditure and calculates historical 2013-2015 category level expenditure levels based on ratios based on how Vector and First Gas allocated expenditure in 2016.

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[305] Vector "Submission on the Gas DPP Draft Decision" (10 March 2017), para 12.

Financial modelling of First Gas transmission

G26 In the DPP financial model, we have modelled the previous MDL and Vector transmission networks separately, calculating the MAR for each network for the pricing year ending 30 September 2018 (the first year of the new DPP period). We then add these two MAR values together to make the MAR for the First Gas transmission network as a whole.

G27 We have taken this approach because much of the input data for the financial model is from historical IDs, and this data is not readily aggregated into a single dataset for the combined network.

G28 A key reason the data was 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 we must apply in setting the DPP starting prices require many of the calculations to be performed on an ID year-end basis.

G29 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.

G30 The 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 quarters,[306] so we can shift the year-end time references for financial model input.

G31 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 Vector transmission Q3 expenditure for 2018 and added the Vector transmission Q3 data for 2017.[307]

G32 Splitting the forecast information into quarters like this assumes that seasonality has little impact on expenditure patterns throughout the year.

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[306] 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.

[307] 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/.

Other regulated income

G33 For the First Gas transmission business, we do 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 (see Attachment F).

G34 For GDBs, the financial model requires as data input a forecast of other regulated income for each BBAR year.

G35 A BBAR year is a 12-month period that coincides with an ID year for the supplier, such that some or all of the BBAR year is within the regulatory period. The year-end of these BBAR years varies between suppliers.

G36 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.

G37 We have 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.

G38 The first year value is 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.

G39 We consider that this revenue to the former Vector gas distribution network should not be treated as other regulated income for setting starting prices. We have projected a nil value of other regulated income for the First Gas and present Vector gas distribution networks.

Disposals

G40 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 has been projected constant in real terms.

G41 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 G37. Values are a historical average, and kept constant in real terms for the regulatory period.

G42 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.

G43 We have changed the way we account for disposals in the financial model. Our accounting for disposals in the final is:

G43.1 The BBAR formulae in financial model for the final decision do not now include terms for the RAB value of disposed assets.

G43.2 For GDBs, the data inputs model adjusts the value of other regulated income (ORI) by the gain/(loss) on disposal. This is no change from the draft decision.

G44 Taken together, these treat disposals appropriately, and compensate the supplier for the RAB value of disposed assets, consistent with the NPV=0 approach. This method is the same as the method used in the 2015 EDB reset.

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 final decision

G45 The final decision publications include the financial model with capex and opex forecast data inputs that have been updated since the draft decision.

G46 WACC information was determined as at 1 March 2017 as required by the IMs and is set out in our WACC determination.[308]

[308] Commerce Commission *Cost of capital determination – GPBs DPP* NZCC5 (31 March 2017), available at: http://www.comcom.govt.nz/dmsdocument/15302. Note the WACC determination has been amended.

G47 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 decision. We received AMPs from GasNet in June 2016; Vector in August 2016; and from both Powerco and First Gas in September 2016.

G48 Table G2 sets out the availability and date received of data from ID Schedules 1 to 10 used in the final decision.

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[309]	Final decision ID data to be used
GasNet	30 Jun	2015 ID data – 21 Dec 2015[310]	2016 ID data – 21 Dec 2016
Vector	30 Jun	2015 disaggregated 53ZD data – 31 Aug 2016[311]	2016 disaggregated ID data – 20 Dec 2016
Powerco	30 Sep	2015 ID data – 17 Mar 2016	2016 ID data – Feb 2017[312]
First Gas dist.	30 Jun	2015 disaggregated 53ZD data – 31 Aug 2016[313]	2016 disaggregated ID data – 19 Dec 2016
First Gas trans. (Maui)	31 Dec	2015 ID data – 30 Jun 2016[314]	2015 ID data – 30 Jun 2016
First Gas trans. (Vector/Kapuni)	30 Jun	2015 ID data – 23 Dec 2015[315]	2016 ID data – 19 Dec 2016

309 The financial model contains updates of all available ID data that was received up to 23 December 2016 except for forecast capex and opex.

310 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.

311 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.

312 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.

313 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.

314 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.

315 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 was available (but not applied in practice) as 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

$Opex_t$ = $opex_{t-1}$ * (1 + Δ due to network scale effects - Δ partial productivity for opex + Δ 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.

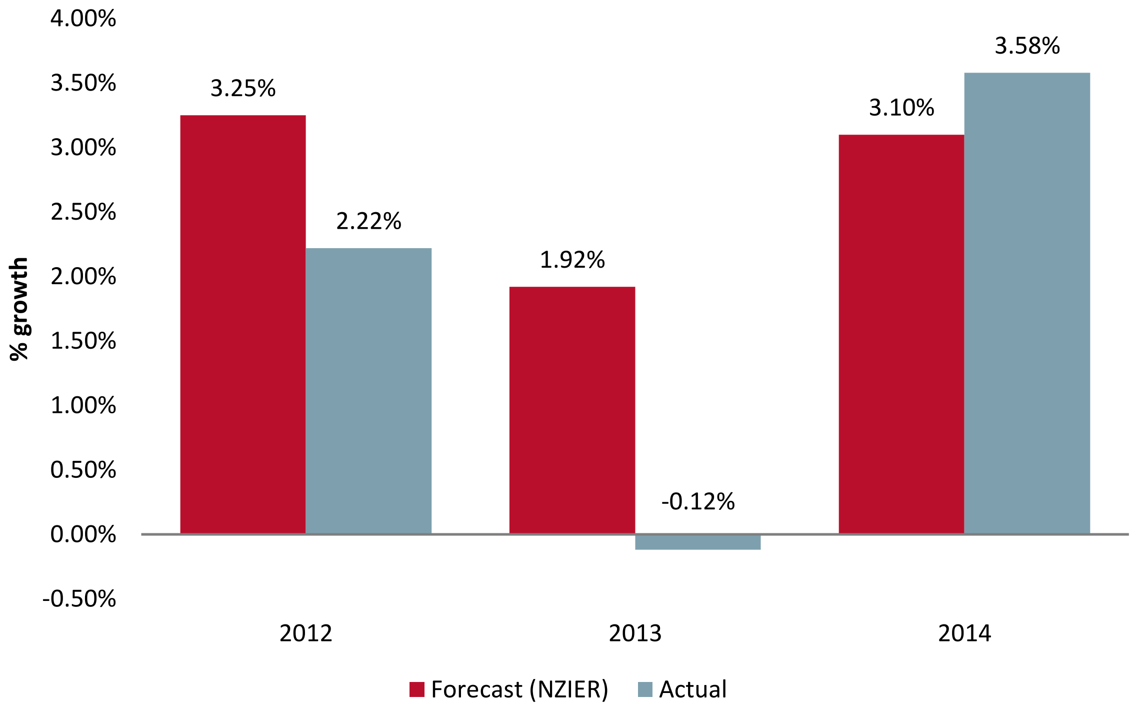
H5.2 partial productivity – improvements in opex partial productivity will reduce the amount of opex needed to provide a given level of service, eg, due to changes in technology.

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; and

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.[316, 317]

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.[318] The CPI forecasts are then adjusted with a premium of -0.17%, in line with advice from NZIER.[319]

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316 *Gas Transmission Services Input Methodologies determination* 2012 [2012] NZCC 28.

317 Email from Shamubeel Eaqub (Principal Economist, NZIER) to the Commerce Commission on extending NZIER forecast horizons (1 October 2010).

318 CPI forecast extended beyond IM guidance by one year.

319 Email from Shamubeel Eaqub (Principal Economist, NZIER) to the Commerce Commission on extending NZIER forecast horizons (1 October 2010).

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 costs by Australian GDBs.[320] 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.[321] 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.[322]

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[320] 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).

[321] Commerce Commission “Low cost forecasting approaches final decision EDB DPP” (November 2014), paras 3.5 and 28.

[322] 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.

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.[323]

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 replicated Castalia's analysis for 2010 and 2012. The 2010 coefficient did not change significantly using real data instead of nominal data.[324, 325, 326]

H23 We have combined the two years and used a pooled approach to estimate the opex scale elasticity. The pooled opex scale elasticity is 0.95, compared with 0.98 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.

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[323] Commerce Commission "Reasons for setting default price quality paths for suppliers of gas pipeline services" (28 February 2013), para C20.

[324] 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

[325] Economic Insights "Relative Opex Efficiency and Forecast Opex Productivity Growth of Jemena Gas Networks" (25 March 2015), page 43.

[326] 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.

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.[327]

Out of trend factors

H28 We have not identified any out of trend factors that need to be applied to the 2017 DPP.

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

List of abbreviations

Abbreviation	Definition
AMP	Asset Management Plans
ANR	Allowable notional revenue
AR	Allowable revenue
ARR	Asset replacement and renewal
BAU	Business as usual
BBAR	Building blocks allowable revenue
CCM	Critical Contingency Management
CCMR	Critical Contingency Management Report
CHC	Chris Harvey Consulting
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
ENA	Electricity Networks Association
FAR	Forecast allowable revenue
FCM	Financial capital maintenance
FRP	Forecast revenue from prices
GDB	Gas distribution businesses
GIC	Gas Industry Company
GPB	Gas pipeline businesses
GTB	Gas transmission businesses
ID	Information Disclosure
IM	Input methodologies
LCI	Labour Cost Index
MAR	Maximum allowable revenue
MDL	Maui Development Limited
MPOC	Maui Pipeline Operating Code
NPV	Net present value
NR	Notional revenue
ORI	Other regulated income
PPI	Produce Price Index
RAB	Regulatory asset base
RCMI	Routine and corrective maintenance and inspection
RPO	Reasonable and Prudent Operator
RTE	Response time to emergencies
WACC	Weighted average cost of capital