HOUSTONKEMP Economists

# Comment on the Commerce Commission's cost of capital update paper

A report for Powerco

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## Disclaimer

# Contents

# 1. Introduction

The New Zealand Commerce Commission ('the Commission') is reviewing the cost of capital input methodologies (IMs). As part of that review, the Commission has released an update paper on the cost of capital in which it calls for new economic evidence on selected cost of capital issues that would feed into its review of the cost of capital IMs.[1]

Powerco has asked HoustonKemp to prepare this report responding to the Commission's cost of capital update paper. In particular, we have been asked to collect and assess evidence in relation to:

- asset beta, and evidence of the extent to which asset betas differ between:
  - firms that are subject to different forms of regulatory control; and
  - electricity distribution businesses ('EDBs') and gas pipeline businesses ('GPBs'); and
- costs associated with raising debt and maintaining the credit rating assumed by the Commission; and
- incentives to apply for a customised price-quality path ('a CPP') for electricity and gas suppliers currently regulated under a default price-quality path ('a DPP').

Each of these areas responds directly to requests by the Commission in its cost of capital update paper for new evidence. A brief summary of our conclusions on these matters follows:

1. There are strong theoretical and empirical reasons suggesting that the form of regulatory control will have an immaterial effect on the systematic risk and asset beta of a supplier.
2. There is evidence that the use and transport of gas in New Zealand is subject to greater systematic risk than the use and transport of electricity. There is also evidence that empirical evidence from the United States as to the relative systematic risk of electricity and gas utilities may not be relevant in the New Zealand context. However, there is limited information available to establish the extent of the quantitative effect of these differences on asset beta.
3. Efficient debt raising practice involves the staggered issuance of debt. To the extent that the IMs set a risk free rate that is fixed for the duration of the regulatory control period, it will likely be efficient for suppliers to hedge their debt exposure to this benchmark, regardless of the term of their debt, to mitigate the mismatch with this allowance.
4. A supplier with benchmark cost of capital characteristics, including a BBB+ credit rating with Standard & Poor's, would need to maintain liquidity ratios and refinance its debt obligations before they fall due. Achieving these benchmarks comes at a cost that is not allowed for under the current IMs.
5. To the extent that the Commission decides it is appropriate to enhance the current incentives to apply for a CPP, practicable options to achieve this include:
   i. adopting the DPP cost of capital as the cost of capital under the CPP; or
   ii. adopting a cost of capital framework that allows changes in the estimated cost of capital to flow more regularly through to the allowed cost of capital.

The remainder of this report is set out as follows:

- section 2 assesses the economic evidence as to how asset betas differ between electricity network businesses and gas pipelines, and whether the form of control matters;
- section 3 considers the Commission's current allowance for debt issuance costs under the IMs and identifies additional expenses associated with prudent debt issuance and refinancing; and

[1] Commerce Commission, *Input methodologies review: Update paper on the cost of capital topic*, 30 November 2015

- section 4 reviews the incentives to apply for a CPP, and a report prepared by Dr Martin Lally of Capital Financial Consultants (CFC).

# 2. Asset beta

We have been asked by Powerco to collect and assess evidence of the extent to which asset betas differ between:

- firms that are subject to different forms of regulation; and
- EDBs and GPBs.

In our assessment, there are compelling reasons to believe that firms subject to different forms of regulation, and, in particular, the weighted average price cap and revenue cap forms of control, do not have materially different systematic risk and asset betas. This view is consistent with empirical findings established in the United States, where the measured asset beta on utilities experiencing rate of return regulation have been compared to those with prices determined under incentive regulation.

Historically, the Commission has estimated a higher asset beta for GPBs than for EDBs on the basis of largely qualitative analysis of the extent of systematic risk faced by GPBs. We source updated data showing that the basis for this assessment is unchanged, or even strengthened. Furthermore, we show that the empirical results based on United States data showing that gas suppliers do not have materially higher asset betas than electricity suppliers is likely to reflect, at least partially, differences in the use of gas between New Zealand and the United States that make gas supply relatively more exposed to systematic risk compared to electricity supply in New Zealand than it is in the United States

## 2.1 Differences in asset beta by form of control

The Commission has called for evidence indicating how the asset beta is affected by the regulatory form of control. This may be important in assessing:

- the relevance of international evidence of the asset beta for New Zealand; and
- whether asset betas should differ within New Zealand due to differences in the form of control.

In assessing differences in asset beta between different forms of control, it is important to note that only systematic risk will affect asset beta. Showing that the form of control would affect the asset beta requires establishing that any differences in risk between different forms of control are:

- systematic risks that they cannot be diversified away; and
- material risks that warrant different levels of compensation.

### 2.1.1 Weighted average price cap and revenue cap regulation

One comparison of forms of control is between a weighted average price cap and a revenue cap approach to regulation. Gas transmission businesses in New Zealand are presently subject to a revenue cap, although this of an asymmetric form, so that forecast-related shortfalls in revenue cannot be recovered, while revenue overruns are netted off the following year's regulatory allowance. EDBs and GPBs more generally are subject to a weighted average price cap.

A weighted average price cap determines a set of prices that, based on the quantity of services that the Commission expects to be provided, will return expected revenues equal to a business' building block allowance over a regulatory control period. If the quantity of the various services actually provided are greater than or lower than expected, the surplus or shortfall is retained by the business and not immediately shared with consumers.

Under a revenue cap, if the quantity of services actually provided are greater or lower than expected when determining the prices, the revenue surplus or shortfall may be added to an 'overs-and-unders' account, which is used to adjust subsequent prices such that the business is eventually made whole only for the building block allowance. This means that under a revenue cap, the revenue received by a supplier over time is not directly linked to the regulators' forecast of quantities.

In our opinion, there are compelling reasons to believe that there are no material differences in systematic risk between these forms of control, for the reasons set out below.

The revenue cap approach shields a service provider from a particular form of risk that the weighted average price cap does not – being the revenue consequences of the quantity of services actually provided during the regulatory period being higher or lower than those forecast by the regulator, when setting the allowed price path, immediately prior to the commencement of the regulatory period. This risk is a function of the regulatory forecasting process, the structure of tariffs, and the intrinsic variability of demand for services over the length of each regulatory period. These risks are quite distinct from the ordinary revenue consequences of cyclical variations in business demand, which relates to financial susceptibility to changes in the services provided.

It may be suggested that one component of these risks – the intrinsic variability of demand for services – has some systematic properties. Both electricity and gas services are inputs into other economic activity and demand for these products may be related to the volume of economic activity more generally – although, to different extents.

However, there is no reason to expect that the risk of error in forecasting the various quantity dimensions (ie, customer connection, capacity and volumes distributed) of electricity and gas distribution services – irrespective of their sensitivity to macroeconomic cycles – over a five year period has systematic properties. For this to be the case, it would need to be established that regulatory forecasts – as the basis on which forward-looking allowed revenues were set – systematically under-estimated demand in macro-economic up cycles, and over-estimated demand in down cycles. In our experience, wider industry-specific trends – such as the uptake of demand-side or energy efficiency measures, and the rates of penetration of domestic gas connections – are likely to be much more important sources of forecast uncertainty.

These observations are consistent with the actions and views of the Australian Energy Regulator (AER) in setting asset beta before and after a change in the form of regulatory control. The AER determined that standard control services for the New South Wales distribution businesses will be regulated between 2014 and 2019 under a revenue cap approach, whereas previously and for other electricity distribution businesses a weighted average price cap was used.[2]

In its final decision, the AER set out extensive reasoning for its position on the cost of capital that it allowed to the New South Wales distribution businesses. Its final decision was to allow an equity beta of 0.7.[3] The approach that the AER took to estimating equity beta was to source empirical estimates of Australian energy network firms. Using this information it formed a view that a reasonable range for equity beta was 0.4 to 0.7, and that it should adopt the number at the top of this range.[4]

Notably, the AER did not adopt a view that its approach to determining equity beta should change to take into account the new form of control that was applied to the New South Wales businesses. Indeed, it specifically rejected the view that differences in the form of control motivates a different allowed cost of capital for electricity businesses.[5]

[2] AER, *Stage 2 Framework and approach: Ausgrid, Endeavour Energy and Essential Energy*, January 2014, p 10.

[3] AER, *Final decision: Ausgrid distribution determination 2015−16 to 2018−19: Attachment 3 – Rate of return*, April 2015, p 13.

[4] Ibid, p 36.

[5] Ibid, p 387.

In the following section we discuss quantitative evidence of the extent to which the form of control affects systematic risk and estimates of asset betas.

### 2.1.2 Quantitative evidence

Most quantitative evidence establishing whether there are differences in asset beta based on the form of control comes from the United States, which has by far the greatest number of listed and regulated utility firms amongst developed countries. The evidence that addresses cross-sectional comparison of betas finds that the form of control does not have a significant association with differences in asset betas between firms.

Analysis of United States data has focused on comparisons between utilities regulated under a rate of return framework and those regulated under an incentive framework. These frameworks are quite distinct from those the revenue cap and weighted average price cap commonly discussed in New Zealand and Australia. The results of these comparisons should not therefore be interpreted as direct evidence about the differences in systematic risk between the revenue cap and the weighted average price cap, but rather the extent to which generally changes in the form of regulation that appear to shift risk between suppliers and consumers actually result in material changes in systematic risk. These studies include:

- an Allen Consulting Group report prepared in 2008 for the Energy Networks Association, Grid Australia and Australian Pipeline Industry Association found that there was not a significant difference between the relevered equity betas of the five firms that they found were subject to incentive regulation and the 21 firms that were subject to rate of return regulation;[6]
- a subsequent report by the Competition Economists Group prepared in 2013 for the Energy Networks Association similarly found that the form of regulation did not give rise to significant differences between asset betas for United States regulated utilities;[7] and
- Gaggero performed a much wider comparison of 170 firms operating in various utilities industries between 1995 and 2004, and found that across his sample the form of control did not result in different levels of risk to regulated firms.[8]

These findings contradict those of Alexander, Mayer and Weeds, who compared betas of the regulated electricity, gas, water and telecoms industries in the United Kingdom and rate of return regulated businesses in the same sectors in the United States.[9] This paper found a significant difference in asset beta between the United Kingdom and the United States for both electricity and gas utilities and concluded that this was due to the form of control. However, these conclusions are likely to be affected by the comparison of asset betas between countries and would likely lead the authors to have overestimated the effect of the form of control on the asset beta. Again, it is relevant to note that the forms of control considered in this study are quite different to the revenue cap and the weighted average price cap.

## 2.2 Differences in asset beta between sectors

The current IMs provide for a higher asset beta for gas network businesses over that allowed for electricity network businesses. The asset beta for gas network businesses is currently 0.44, as against 0.34 for EDBs and Transpower.[10]

Powerco has asked us to review the basis for the higher asset beta that is allowed for gas network businesses and to assess the strength of the evidence supporting this uplift. We find that there is continued evidence that the use and transport of gas in New Zealand is subject to greater systematic risk than the use

[6] ACG, *Beta for regulated electricity transmission and distribution*, 17 September 2008

[7] CEG, *Information on equity beta from US companies*, June 2013

[8] Gaggero, A. (2012). "Regulation and Risk: A Cross-Country Survey of Regulated Companies," *Bulletin of Economic Research*, 64(2), pp 226-238.

[9] Alexander, I., C. Mayer, and H. Weeds (1996). "Regulatory Structure and Risk and Infrastructure Firms: An International Comparison," World Bank Policy Research Working Paper No. 1698, December.

[10] Commerce Commission, *Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons paper*, December 2010, pp 160-161

and transport of electricity. There is also evidence that empirical evidence from the United States may not be relevant in the New Zealand context. However, there is limited direct empirical evidence on which to establish the extent of the effect of these differences on asset beta in New Zealand.

It is relevant to note that the sole piece of evidence cited by the Commission's cost of capital update paper[11] in connection with its intention to revisit the asset beta uplift for gas network businesses was a comment from Frontier, on behalf of Transpower, that:[12]

> The Commission itself adopts a beta premium of 0.10 for gas pipeline businesses relative to electricity distribution businesses, yet beta estimates do not differ between firms that are predominantly gas versus electricity businesses.

The comment quoted by the Commission was only a one sentence summary of Frontier's position. Frontier's complete discussion of on the relative risks for EDBs and GPBs suggested that there may be differences in risk profiles between electricity and gas networks and that the Commission's framework for determining the cost of equity is unable to adequately capture these.[13] This more complete elucidation of Frontier's position is a useful basis upon which to consider whether an asset beta uplift is required.

### 2.2.1 Discretionary nature of gas demand

It is important to consider these issues against the broader context in which electricity and gas are consumed within the economy. Electricity and gas are sources of energy that may be in competition with each other, and with alternative fuels, at customers' premises. The final price paid by customers includes the commodity cost of purchasing energy, the cost of transporting it to the premises, plus any retail margin. Long-term demand risks faced by suppliers of electricity and gas are therefore also experienced by networks, since they cannot readily be used for any other purpose.

There are good reasons to expect that New Zealand gas network businesses may face greater risks than New Zealand electricity network businesses. The most important of these is the discretionary nature of gas consumption for many uses. Many common appliances and industrial processes only use electricity. The primary uses of gas, for heating and cooking, compete with electricity and other fuels for all but a few industrial uses. This suggests that supply of gas to small customers, in particular, may be exposed to the risk of being displaced by electricity and other fuels. A fuller description of these risks is set out in Concept Consulting's report for Powerco.[14]

These risks are likely to be material. There is also some evidence that they may be systematic. Research into determinants of residential demand for electricity and gas in Australia has previously shown that the income elasticity of demand for gas is much higher than for electricity and is significantly greater than unity.[15] This suggests that, in Australia, gas as a "luxury good". This economic term describes a good for which demand increases more than proportionately with income. Other things being equal, we would expect luxury goods to be exposed to greater systematic risks than 'normal' goods, such as electricity, because changes in income are closely linked to economic growth.

We consider that the Australian empirical data provides relevant information in informing policy decisions in New Zealand. Results based on New Zealand data would be preferable, but we are not aware of any studies that investigate the income elasticity of demand for gas in New Zealand. Although Australia has a different

[11] Commerce Commission, *Input methodologies review: Update paper on the cost of capital topic*, 30 November 2015, p 8

[12] Frontier Economics, *Recommendations on priorities for review of cost of capital input methodology: A report prepared for Transpower New Zealand*, August 2015, pp 44-45

[13] Ibid, pp 51-52

[14] Concept Consulting, *Relative long-term demand risk between electricity and gas networks*, 23 January 2016

[15] Akmal, A. and Stern. D, 'Residential energy demand in Australia: an application of dynamic OLS', Working papers in ecological economics, October 2001

gas market context from New Zealand, it may nonetheless be more comparable than gas markets in other developed economies in North America and Europe.

### 2.2.2 Current basis for higher asset betas for GPBs

The higher asset beta for GPBs applied by the Commission is due to expectations that GPBs in New Zealand would be expected to have higher levels of systematic risk than EDBs. The original rationale for this difference was set out by the Commission's advisor, Dr Lally, in 2004.[16]

Dr Lally identified a number of factors that might be expected to influence systematic risk, and assessed the extent to which these factors may argue for different levels of systematic risk for EDBs and GPBs. He identified three factors that may give rise to some difference, being that:

- 30 per cent of gas is used as an intermediate product in the petrochemical industry, which suggests a higher income elasticity of demand for gas, and therefore higher systematic risk;
- while a large proportion of gas is used to generate electricity, some part of this is used in peaking supply. To the extent that this use is material, changes in electricity demand could give rise to much more significant changes in demand for gas for this purpose; and
- gas is more predominantly used by commercial and industrial users in the production of final goods and services than is the case for electricity – 82 per cent for gas (including the production of petrochemicals) as compared to 68 per cent for electricity. Since the demand for these final goods and services is likely to be more susceptible to macroeconomic shocks than final consumption of electricity and gas, this suggests that the supply and transport of gas has a greater systematic risk than the supply and transport of electricity.

Dr Lally considered that these three points, and particularly the last one, which he considered the most persuasive, were sufficient to justify an asset beta for GPBs ranging from 0.4 to 0.6, higher than the range of 0.3 to 0.5 that he had estimated for EDBs in a previous report.[17] Dr Lally did not explain the basis upon which he came to the view that an uplift of 0.10 in asset beta was a sufficient and reasonable additional level of compensation reflecting the risks faced by GPBs.

Our analysis based on updated energy statistics suggests that none of the facts relied upon by Dr Lally in coming to his view in 2004 have materially changed. The most recent energy use information available is for the year ending September 2015, from the Ministry of Business, Innovation and Employment's (MBIE's) Energy in New Zealand 2015 publication.[18] Using this information, we find that:

- 68 per cent of electricity consumption is used for commercial or industrial purposes; and
- 86 per cent of New Zealand's gas is used by commerce and industry, including:
  - 37 per cent of gas that is directly used by commerce and industry;
  - 32 per cent of gas is converted into electricity, of which 68 per cent is used by commerce and industry; and
  - 27 per cent of gas is used to produce methanol or urea.

Even if the gas used to produce methanol and urea is excluded from the calculation, a sensitivity examined by Dr Lally, the proportion consumed by commerce and industry is still 81 per cent. We note that these facts are consistent with similar analysis drawn from the MBIE dataset by Concept.[19] They contribute to a

[16] Martin Lally, *The weighted average cost of capital for gas pipeline businesses*, 14 May 2004

[17] Ibid.

[18] MBIE website, http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/publications/energy-in-new-zealand, accessed 19 January 2016

[19] Concept Consulting, *Relative long-term demand risk between electricity and gas networks*, 23 January 2016

conclusion that the supply and transport of gas in New Zealand is likely to be more exposed to systematic risk than the supply and transport of electricity.

### 2.2.3 Comparisons with the United States

Whereas energy statistics for New Zealand show that the consumption of gas for intermediate use is greater than electricity, energy statistics for the United States do not show differences to the same extent. Since this is a key rationale for a higher relative asset beta for gas network businesses in New Zealand, these data suggest that empirical results from the United States have diminished relevance for New Zealand and may tend to underestimate the difference in systematic risk.

Empirical analysis of differences between asset betas for electricity and gas network businesses has focused on the United States, where there are many listed energy utilities. This larger population of regulated utilities allows direct (cross-sectional) comparisons between the equity betas of gas and electric utilities.

For instance, the Competition Economists Group performed a survey of United States asset betas for the Australian Energy Networks Association in 2013.[20] Previous research was performed by PricewaterhouseCoopers for Ofgem in 2009.[21]

It is important to consider whether the results predominantly derived from United States comparisons are valid for New Zealand. To address this question, it may be helpful to apply Dr Lally's method for evaluating differences in systematic risk between electricity and gas in New Zealand to data sourced from the United States. We have completed this analysis using data from the Energy Information Administration (EIA), a unit of the Department of Energy and an authoritative source of energy data in the United States.

In the United States, consumption of electricity for commercial and industrial purposes is lower than New Zealand, at 62 per cent for the 12 months ending September 2015. The consumption of gas for commercial and industrial purposes over the same period was 69 per cent, consisting of:[22]

- 48 per cent directly used by commerce and industry; and
- 34 per cent used in the electricity generation sector, of which 62 per cent is ultimately consumed by commerce and industry.

These statistics suggest that the differences between consumption of electricity and gas are not as pronounced in the United States as they are in New Zealand. The total consumption of gas by the household sector is much more significant in the United States than it is in New Zealand, both directly and once the effect of consumption of gas-fired generation is accounted for.

In summary, these results indicate that there are some reasons to expect that differences in systematic risk between EBDs and GPBs are greater in New Zealand than in the United States. This suggests that empirical results from the United States may not be applicable in the New Zealand context and would underestimate the extent of differences in systematic risk in New Zealand.

[20] CEG, *Information on equity beta from US companies*, June 2013

[21] PwC, *Advice on the cost of capital analysis for DPCR5, Final Report to the Office of Gas and Electricity Markets*, 28 July 2009

[22] EIA website, http://www.eia.gov/totalenergy/data/monthly/index.cfm#consumption, accessed 19 January 2016. We used tables 4.3 and 7.6 to derive these estimates.

# 3. Debt issuance and transaction costs

Powerco has asked us to collect and assess evidence relating to specific debt issuance and transaction costs that it incurs, and that an efficient supplier operating consistently with the Commission's cost of capital framework would incur, but for which there is not an explicit allowance for under the current IMs. Specifically we have been asked to assess:

- the transaction costs of entering into interest rate swaps; and
- the costs incurred in complying with criteria applied by Standard & Poor's in assessing the credit ratings of businesses, including:
  - the requirement to maintain liquidity; and
  - the requirement to refinance debt facilities in advance of their maturity date.

A business seeking to match its actual cost of debt as closely as possible to the allowed cost of debt may enter into interest rate swaps. The costs of entering into these swap transactions has been estimated by the Commission in its recent decision for Chorus as eight basis points over the entire debt portfolio. However, the current IMs only allow swap transactions costs as part of the term credit spread differential allowance (TCSDA), for debt with terms of more than five years.

In our opinion, it is important that the Commission aligns its cost of debt framework with a coherent and prudent approach to debt raising. If the debt raising approach assumed by the Commission requires fixing interest rates immediately prior to the start of each regulatory control period, then suppliers will need to enter interest rate swaps to achieve this. The cost of entering such interest rate swaps should be reflected in allowed revenue.

The Commission's current IMs assume that the regulated entity maintains a BBB+ credit rating with Standard and Poor's. We note that maintaining a credit rating of any level requires a supplier to meet particular standards in respect of the liquidity that it must maintain and how it goes about refinancing its debt obligations. Meeting these obligations incurs costs, which are incurred in connection with the Commission's financing assumptions. In our view, these costs should be provided for in suppliers' allowed revenue.

We discuss these issues in more detail in the remainder of this section.

## 3.1 Cost of interest rate swaps

A supplier seeking to match its actual cost of debt as closely as possible to the allowed cost of debt under the current IMs may enter into interest rate swaps. This type of hedging is likely to be a prudent response to the Commission's framework for determining the cost of debt under the current IMs. In our opinion, the Commission's review of the cost of capital IMs should investigate the transactions costs of interest rate swaps and provide for these costs in its cost of debt allowance. This is consistent with the position that the Commission has come to in its final decision on the cost of capital applying to Chorus' unbundled copper local loop and universal bitstream access services.

### 3.1.1 Debt issuance practices

Under the current IMs, the cost of debt allowance for the *majority* of suppliers is determined as the five year yield on BBB+ corporate bonds prevailing in a period prior to the beginning of the regulatory control period. The cost of debt is not updated during the regulatory control period and the transactions costs of interest rate swaps are not included in the cost of debt allowance.

For those suppliers that issue some debt at terms of more than five years, the current IMs provide for an additional TCSDA that takes into account on the qualifying debt only:

- different debt premiums between seven year and five year BBB+ bonds;
- transactions costs of swaps; and
- reductions in debt issuance costs as upfront expenditure is amortised over a longer term.

However, the compensation that the current IMs provide for five year debt is consistent with an assumption that suppliers raise their entire debt portfolio for an upcoming regulatory control period:

- during a narrow window prior to the beginning of the regulatory control period; and
- for a uniform term of five years such that the debt all falls due at approximately the same time.

These assumptions underlie the claims by the Commission and its advisor, Dr Lally, that compensation for the cost of debt is present value neutral, ie, that it satisfies the 'NPV=0' principle. This principle would indeed be satisfied if suppliers actually raised debt in a manner consistent with the assumptions above or if it were efficient for them to do so. If these assumptions could be sustained, then suppliers might seek to match the cost of debt allowance under the IMs by adopting a matching debt issuance strategy.

However, in practice, prudent debt management behaviour is not consistent with the assumptions that underlie the compensation for the cost of debt under the current IMs. It is common practice for businesses to engage in staggered debt issuance so that debt obligations do not fall due in a lumpy fashion that would expose a business to an unwarranted level of interest rate risk in seeking to refinance this obligation. Raising all debt each five years to fall due at the same time five years later is not a prudent debt issuance practice. Even if it could be assumed to be prudent for one supplier, it seems unlikely that it would be prudent (or indeed possible) for all suppliers to simultaneously issue their entire debt portfolio over five years prior to the regulatory control period.

The fundamental question facing the Commission in its review of the framework for the cost of debt is whether:

- the approach to regulation should inform an assessment of what is, or is not, a prudent and efficient debt raising practice, as it does under the current IMs; or
- prudent and efficient debt raising practices should inform an assessment of the approach to regulation.

Both of these approaches can be consistent with a present value neutral approach to determining the cost of debt. However, only the second reflects efficient behaviour that seeks to minimise risks in a commercially sensible way.

### 3.1.2 Requirement for interest rate swaps

For suppliers that engage in staggered debt issuance, a prudent response to the framework for setting the cost of debt under the current IMs might involve entering into interest rate swaps to fix the base rate exposure over the regulatory control period.

An interest rate swap is an instrument that allows a business to convert its exposure to floating rate interest payments into fixed rate payments, or vice versa. A supplier that issues fixed rate debt, but seeks to fix its base rate exposure over the regulatory control period, will enter into two sets of interest rate swaps and will therefore incur the costs of swaps twice:

- it will swap fixed rate debt into floating rate debt at or near issuance, ensuring that all debt is subject to floating rate exposure prior to the start of the regulatory control period; and
- it will swap this floating rate exposure back into a fixed rate exposure, fixed for five years, over a period consistent with when the Commission measures the risk free rate.

Entering into these arrangements will not allow a supplier to match the cost of debt allowance under the IMs. As noted above, this is not possible unless the supplier engages in lumpy debt issuance. However, interest rate swaps can allow a supplier to approximately match the risk free rate component of the cost of debt, leaving it exposed only to movements in the debt premium.

These transactions are consistent with the basis used by the Commission to estimate the transactions costs of swaps for Chorus in its recent final decision. In that decision, the Commission allowed for transactions costs of swaps of eight basis points on the basis of executing two swaps as described above.[23] The Commission reasoned that an efficient operator would seek to manage interest rate risk by entering into interest rate swaps that allow the operator to align the interest rate setting to the price setting.

The Commission's reasoning for Chorus was in the context of its assumed term for the cost of debt of seven years. However, consistent with our reasoning above, we recommend that the Commission provide for the transactions cost of swaps where it has also fixed the risk free rate over the term of the regulatory control period – regardless of the assumed term of debt.

### 3.1.3 Estimating the transactions costs of swaps

In the current IMs and in its final determination for Chorus, the Commission estimates the cost of a swap transaction as half the spread between the ask yield and the bid yield for five year interest rate swaps – that is, the mid to ask spread. In the Chorus determination it estimates this as four basis points for each swap transaction.

In our view, this basis for determining the transactions cost of swaps is not likely to give rise to an estimate that reflects the achievable costs of any supplier engaged in interest rate swaps. Using the mid to ask spread is consistent with an assumption that the supplier engages directly in the market for interest rate swaps and that it incurs no additional costs in doing so. In practice, there are additional costs for engaging in this market, including:

- execution spreads payable to a broker (usually a bank) for its costs in completing the transaction; and
- credit spreads payable, reflecting the risk of transacting with the supplier.

In respect of the second point, we note that interest rate swap yields are quoted on the basis of bank-to-bank transactions. Where the broker (a bank) transacts these on behalf of a supplier, it takes on the credit risk of the supplier and therefore charges to cover for this.

We understand that the Commission is collecting a large amount of debt information from suppliers, and that this information will include data about the costs of engaging in interest rate swaps. We consider that the best estimate of the transactions costs of interest rate swaps are likely to come from this source, rather than a synthetic estimate based on spreads for instruments that cannot be directly transacted by EDBs and GPBs.

## 3.2 Costs associated with credit rating requirements

The current IMs assume that EDBs and GPBs maintain a credit rating of BBB+ with Standard & Poor's.[24] This assumption is a key factor determining the allowance that the Commission provides for the cost of debt.

Standard & Poor's sets out rating methodologies and criteria that determine whether EDBs and GPBs, as well as other businesses, are rated BBB+. Complying with these requirements imposes costs on suppliers and would impose costs on the hypothetical supplier modelled by the Commission. We consider that the costs associated with achieving and maintaining the credit rating assumed for the regulated supplier should

[23] Commerce Commission, *Final pricing review determination for Chorus' unbundled bitstream*, 15 December 2015, p 109; and Commerce Commission, *Final pricing review determination for Chorus' unbundled copper local loop service*, 15 December 2015, p 124

[24] Commerce Commission, *Gas Distribution Services Input Methodologies Determination 2012*, 16 December 2013, p 53, para 2.4.4(1), and Commerce Commission, *Electricity Distribution Services Input Methodologies Determination 2012*, 15 November 2012, p 60, para 2.4.4(1).

be estimated and provided for in suppliers' revenue allowance, since they reflect costs that are efficiently incurred in maintaining a financing structure consistent with the regulatory framework.

The Commission's current IMs review is an opportunity to review how costs associated with maintaining an appropriate credit rating is provided for in the IMs. Two of these requirements that we quantify in this report relate to liquidity and how businesses should seek to refinance their debt obligations. We present an approach to calculating these costs and estimate their magnitude in section 3.2.1 and section 3.2.2 below.

### 3.2.1 Cost of maintaining liquidity

A key requirement for achieving a BBB+ credit rating is to maintain sufficient liquidity or 'headroom' so that suppliers are able to absorb adverse movements in cash flows without breaching financial covenants. To assess whether a business has sufficient liquidity, Standard & Poor's considers the relationship between sources of liquidity (designated as 'A') and uses of liquidity (designated as 'B'). Potential sources and uses of liquidity are set out in Table 1 below.

Table 1: Sources and uses of liquidity

| A: Sources of liquidity[25] | B: Uses of liquidity[26] |
|---|---|
| Cash and liquid investments | Forecasted funds from operations, if negative |
| Forecasted funds from operations (FFO), if positive | Expected capital spending |
| Forecasted working capital inflows, if positive | Forecasted working capital outflows, if negative |
| Proceeds of asset sales (when confidently predictable) | All debt maturities either recourse to the company or which it is expected to support (including outstanding CP maturities) |
| The undrawn, available portion of committed credit facilities maturing beyond the next 12 months. | Any required cash-based, postretirement employee benefit top-up needs |
| Expected ongoing support | Credit puts that cause debt acceleration or new collateral posting requirements in the event of a downgrade of up to three notches |
| | Contracted acquisitions and expected shareholder distributions under a stress scenario, including expected share repurchases |

*Source: Standard & Poor's*

Standard & Poor's methodology for determining corporate credit ratings sets out that a business must maintain an 'adequate' level of liquidity in order to qualify for a BBB+ rating.[27] 'Adequate' liquidity means that a company is able to withstand adverse market circumstances over the next 12 months while maintaining sufficient liquidity to meet its obligations.[28] For a business to be considered to have 'adequate' liquidity by Standard & Poor's, it must:[29]

- have a ratio of sources to uses of liquidity (the A/B ratio) of at least 1.2 over the upcoming 12 months;
- maintain sources of liquidity higher than uses (A-B), even if forecasted EBITDA declines by 15 per cent;

[25] Standard & Poors, *Criteria* | *Corporates* | *General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers*, 17 December 2014, clause 23.

[26] Standard & Poors, *Criteria* | *Corporates* | *General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers*, 17 December 2014, clause 30.

[27] Standard & Poors, *Criteria* | *Corporates* | *General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers*, 16 December 2015, para 10.

[28] Standard & Poors, *Criteria* | *Corporates* | *General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers*, 16 December 2015, para 37.

[29] Standard & Poors, *Criteria* | *Corporates* | *General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers*, 16 December 2015, para 37.

- retain sufficient covenant headroom for forecasted EBITDA to decline by 15 per cent without the company breaching coverage tests, and debt is at least 15 per cent below covenant limits (or, if not, the related facilities are not material);
- maintain sound relationships with banks;
- retain a generally satisfactory standing in credit markets – this can be assessed from equity, debt, and derivative trading data relative to peers' and market averages; and
- adopt generally prudent risk management – to meet this assessment, the company needs to show evidence that its management anticipated potential setbacks and took the necessary actions to ensure continued adequate liquidity, as well as demonstrate sufficient intra-year liquidity management.

However, it is still possible for a business to achieve a BBB+ credit rating without meeting the liquidity tests in the first two points above where the company has:[30]

- an anchor rating – based only on financial risk and business risk profiles and before other factors – of at least BBB-;
- well established and solid relationships with banks;
- a generally high standing in credit markets;
- generally prudent risk management; and
- a credible plan that will result in the A/B and A-B tests meeting the minimum requirements set out above at least three months before the refinancing date.

Maintaining liquidity for a BBB+ credit rating requires an efficient supplier to incur costs. These costs typically relate to headroom facility fees, since undrawn headroom facilities are the principal method that regulated businesses employ to ensure liquidity. Headroom facility fees are paid to financiers to compensate them for agreeing to a legally binding commitment to provide funds at the borrower's request. Since headroom facility fees are an additional consequence of maintaining an acceptable headroom rating, it follows that these costs should be included the cost of debt allowance. However, headroom facility fees are not currently compensated as part of the allowance for the cost of debt.

The required headroom facility and associated headroom facility fees can be quantified based on data from the Commission's price path determinations and general assumptions concerning leverage, and debt retirement, as detailed in Table 2 below.

Table 2: Components to calculate headroom facility fees

| A: Sources of liquidity | B: Uses of liquidity |
|---|---|
| **Liquidity from operations**<br>Calculated from maximum allowable revenue less operational expenses based on the data from the Commission's DPP determinations for EDBs and GPBs. | **Capital expenditure**<br>Based on the data from the Commission's DPP determinations for EDBs and GPBs. |
| **Liquidity from headroom facilities**<br>Calculated from the required facility for 'adequate' liquidity taking into account the liquidity from operations, capital expenditure and debt repayments. | **Debt repayments**<br>Calculated from 44 per cent debt financing of RAB and assuming 1/5 debt retirement each year. RAB is based on the data from the Commission's DPP determinations for EDBs and GPBs, while leverage is based on the IMs parameter value. |

To calculate the size of the headroom facility required to have 'adequate' liquidity, we first consider the required A/B ratio of 1.2. This can be expressed in terms of the components detailed in Table 2:

[30] Standard & Poors, *Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers*, 16 December 2015, para 38 and para 39.

1.2 = (liquidity from operations × 0.85 + liquidity from headroom facilities) / (capital expenditure + repayments)

Rearranging the equation above for liquidity from headroom facilities we obtain the required liquidity from headroom facility:

Required liquidity from headroom facility = 1.2 × (capital expenditure + repayments) – 0.85 × (maximum allowable revenue – operating expenses)

To calculate the cost for a headroom facility, we multiply the fee for the headroom facility (expressed in basis points) by the amount of the headroom facility required for 'adequate' liquidity:

Cost for headroom facility = fee for headroom facility × required liquidity from headroomfacility

We understand the cost of headroom facilities is typically around 50 to 60 basis points per annum but can vary significantly depending on the structure of the headroom facility agreement. Fees charged by financial institutions for headroom facilities are likely to warrant further consideration from the Commission as it collects information about the cost of debt from EDBs and GPBs.

To show how Standard & Poor's requirements can be operationalised in the context of the application of the IMs, we have applied them to each of Powerco's EDB and GPB, using four years of data from the most Commission's most recent DPP determinations for electricity and gas respectively.

Table 3: Headroom facility fee calculation for Powerco's EDB ($,000)

| | 2015/16 | 2016/17 | 2017/18 | 2018/19 |
|---|---|---|---|---|
| **Debt financing calculation** | | | | |
| EDB closing RAB | 1,540,185 | 1,593,317 | 1,659,480 | 1,721,572 |
| Debt financing (44 per cent) | 677,682 | 701,059 | 730,171 | 757,492 |
| **Use of liquidity** | | | | |
| Debt repayments | 131,664 | 135,536 | 140,212 | 146,034 |
| Capital expenditure | 94,625 | 100,364 | 115,022 | 114,442 |
| Total | 226,289 | 235,900 | 255,234 | 260,476 |
| **Sources of liquidity** | | | | |
| EDB Maximum allowable revenue | 250,424 | 254,347 | 259,009 | 264,621 |
| EDB Nominal price network opex series | -31,894 | -32,951 | -33,915 | -34,906 |
| Total | 185,751 | 188,187 | 191,329 | 195,258 |
| **Debt facility calculation** | | | | |
| Required liquidity | 271,546 | 283,080 | 306,281 | 312,571 |
| Required debt facility | 85,796 | 94,893 | 114,951 | 117,313 |
| **Debt facility fee** | **429** | **474** | **575** | **587** |

*Source: Commerce Commission, HoustonKemp analysis*

Over the period from 2015/16 to 2018/19, we estimate benchmark debt facility fees for Powerco's EDB to be on average $516,000 per annum on an average debt facility of approximately $103 million.

Table 4: Benchmark facility fee calculation for Powerco's GDB ($,000)

| | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|
| **Debt financing calculation** | | | | |
| GDB closing RAB | 367,966 | 378,897 | 389,540 | 400,146 |
| Debt financing (44 per cent) | 156,989 | 161,905 | 166,715 | 171,398 |
| **Use of liquidity** | | | | |
| Debt repayments (1/5 each year over 5 years) | 31,398 | 32,381 | 33,343 | 34,280 |
| Capital expenditure | 12,750 | 13,154 | 13,550 | 13,817 |
| Total | 44,148 | 45,535 | 46,893 | 48,097 |
| **Sources of liquidity** | | | | |
| GDB Maximum allowable revenue | 47,076 | 48,134 | 49,239 | 50,316 |
| GDB Nominal price network opex series | -17,318 | -17,928 | -18,467 | -19,058 |
| Total | 24,960 | 25,294 | 25,675 | 26,156 |
| **Debt facility calculation** | | | | |
| Required liquidity | 52,977 | 54,642 | 56,272 | 57,716 |
| Required debt facility | 27,683 | 28,967 | 30,115 | 31,147 |
| **Debt facility fee** | **138** | **145** | **151** | **156** |

Over the period from 2014/15 to 2017/18, we estimate benchmark debt facility fees for Powerco's GDB to be on average $147,000 per annum on an average debt facility of approximately $29 million.

In total, benchmark debt facility fees across Powerco's EDB and GPB are $663,000 per annum on a total average debt facility of $132 million. We note that Powerco's actual debt facility fees may be lower than this, reflecting differences between Powerco and the benchmark. One key factor affecting these differences is that Powerco maintains a BBB rating with Standard & Poor's, rather than the assumed BBB+ rating for the benchmark. The liquidity requirements with which it must comply to maintain this rating are therefore more relaxed than those set out by Standard & Poor's for BBB+ issuers.

### 3.2.2 Debt refinancing risks and the cost of carry

Typically, it is not possible for large businesses such as EDBs and GDBs to refinance debt on the day that existing facilities mature. This is because any disruptions in the debt raising process could affect a business' ability to meet its obligations as and when they fall due. To avoid exposure to refinancing risks businesses typically arrange financing prior to the maturity of existing debt facilities in order to manage cash flow risks from maturing debt.

Standard & Poor's considers this risk in an article published in 2008 titled '*Refinancing And Liquidity Risks Remain, But Australia's Rated Corporates Are Set To Clear The Debt Logjam*', indicating that the timing which new debt facilities are arranged is considered in its credit ratings. The article states:[31]

[31] Standard & Poors, *Refinancing And Liquidity Risks Remain, But Australia's Rated Corporates Are Set To Clear The Debt Logjam*, 22 April 2008.

> For the Australian investment-grade corporates, we expect to see a measured and logical approach to meet upcoming debt maturities. We would want to see that the company has a credible strategy for repaying or refinancing debt maturing up to 18 months ahead. As maturities move into the forward 12-month time horizon, we will start placing more weight within the short-term rating analysis on the materiality of upcoming maturities and the company's refinancing strategy and execution ability. To avoid negative rating consequences, the ideal progression would be:
>
> - 12 to 18 months ahead of maturity, the company would have a detailed and credible refinancing plan (including a contingency plan);
> - no less than six months ahead of the maturity, the company could have documentation substantially in place for the replacement debt issue/s; and
> - no less than three months ahead of maturity, the refinancing would be essentially completed, committed, or underwritten.

The position taken by Standard & Poor's indicates that companies will need to have new debt funding in place three months prior to the maturity of existing debt in order to avoid negative rating consequences. By meeting this requirement, businesses will incur additional interest costs from holding additional debt balances over a three month period. This 'cost of carry' is an efficiently incurred cost that is consistent with the requirement for a benchmark supplier to hold a credit rating of BBB+ with Standard & Poor's.

The cost of carry is created because businesses must refinance at least three months early, and therefore incur double interest payments over this three month period. However, the cost of carry is not the full quantum of these additional interest payments. Businesses may be able to invest the cash inflows generated through early renewal of debt facilities in a short term instrument until it is required to repay the principal of the expiring debt facility. Necessarily, the instrument must be low risk since if there is a material risk of default, the purpose of renewing debt early will be defeated.

There are limited options for investing funds in New Zealand due to debt markets being smaller and less liquid relative to the size of funds that are to be invested. Two investment options in New Zealand that we have considered are three-month treasury bills and three-month bank bills.

The amount of debt refinancing requirements can be approximated by assuming that 44 per cent of the RAB is financed by debt and that one fifth of debt is refinanced each year over a five year period, consistent with the assumed debt financing structure of EDBs and GPBs. This is expressed in the following formula:

$$\text{Amount of debt refinancing} = \text{RAB} \times 0.44 \times 1/5$$

The net carrying costs are calculated by multiplying the amount of debt requiring refinancing by the spread between the cost of debt and the return on investment, the product of which is then multiplied by one quarter to reflect carrying costs for three months:

$$\text{Net carrying costs} = \text{amount of debt refinancing} \times \text{spread} \times 1/4$$

As with the cost of liquidity, we present an example calculation of a benchmark cost of carry for Powerco's EDB and GPB over their respectively current DPPs.

We provide estimates for the cost of carry based on a cost of debt of 6.09 per cent[32] and one fifth of debt is refinanced each year over a five year period. Table 5 sets out the assumed rate of return on investment used to calculate the spread.

[32] Commerce Commission, *Financial model – EDB DDP 2015-2020*, 28 November 2014, Tab: Inputs.

## Table 5: Assumed return on cash from renewed debt facilities

| Investment | Yield | Cost of debt - yield |
|---|---|---|
| Bank bills[33] | 3.69 per cent | 2.40 per cent |
| Treasury bills[34] | 3.49 per cent | 2.60 per cent |

Table 6 details the calculation for a benchmark net cost of carry for Powerco's EDB over 2015/16 to 2018/19. The average cost of carry over this period is $830,000 per annum.

## Table 6: Cost of carry calculation for Powerco's EDB($,000)

| | 2015/16 | 2016/17 | 2017/18 | 2018/19 |
|---|---|---|---|---|
| **Debt financing calculation** | | | | |
| EDB closing RAB | 1,540,185 | 1,593,317 | 1,659,480 | 1,721,572 |
| Debt financing (44 per cent) | 677,682 | 701,059 | 730,171 | 757,492 |
| Debt refinanced | 131,664 | 135,536 | 140,212 | 146,034 |
| Cost of carry | 2,005 | 2,064 | 2,135 | 2,223 |
| Return on investment | 1,215 | 1,250 | 1,293 | 1,347 |
| **Net cost of carry** | **790** | **813** | **841** | **876** |

Table 7 details the calculation for a benchmark cost of carry for Powerco's GDB over 2014/15 to 2017/18. The average cost of carry is $197,000 per annum.

## Table 7: Cost of carry calculation for Powerco's GDB ($,000)

| | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|
| **Debt financing calculation** | | | | |
| GDB closing RAB | 367,966 | 378,897 | 389,540 | 400,146 |
| Debt financing (44 per cent) | 161,905 | 166,715 | 171,398 | 176,064 |
| Debt refinanced | 31,398 | 32,381 | 33,343 | 34,280 |
| Cost of carry | 478 | 493 | 508 | 522 |
| Return on investment | 290 | 299 | 308 | 316 |
| **Net cost of carry** | **188** | **194** | **200** | **206** |

In total, we estimate the benchmark net cost of carry across Powerco's EDB and GPB as approximately $1,027,000 per year,

[33] The bank bill rate of 3.69 per cent is sourced from Bloomberg BDBB3M Curncy for 1 September 2014.

[34] The Treasury bill rate of 3.69 per cent is sourced from Bloomberg NDTB3M Curncy for 1 September 2014.

# 4. Incentives to apply for a CPP

The Commission has highlighted that suppliers regulated under a DPP may face incentives to apply, or not apply, for a CPP due to differences in the cost of capital that would be allowed under the CPP.[35]

The Commission has asked its consultant, Dr Lally, to prepare a report assessing options for addressing the incentives to apply for a CPP. In his paper for the Commission, Dr Lally develops a proposal to address incentives that arise to apply for a CPP when the cost of capital applying to the DPP has changed. Dr Lally concludes that a CPP should:[36]

- apply the existing DPP cost of capital to existing assets;
- apply the existing DPP cost of capital to capital expenditure envisaged under the DPP, unless the Commission concludes this gives rise to unspecified incentive problems; and
- apply a new CPP cost of capital to any new capital expenditure allowed by the CPP, over and above capital expenditure envisaged under the DPP.

Dr Lally also notes that this recommendation may be difficult to implement, and proposes a second-best solution that would avoid complexities by adopting the existing DPP cost of capital under any CPP sought by a supplier.

Powerco has asked us to assess the proposed responses developed by the Commission and its consultant, Dr Lally, to these incentives.

In our view, the claimed benefits of the split cost of capital concept rely on an analysis of incentives that assumes a level of accuracy and precision in cost of capital estimates well beyond what is in practice achieved in the current IMs. Furthermore, we consider that Dr Lally has not fully investigated the potential problems with implementing the split cost of capital concept. The net benefits of this approach are likely to be considerably less than those assumed by Dr Lally in recommending it to the Commission.

However, we consider that Dr Lally's alternative recommendation of relying on the DPP cost of capital has merit if the Commission is minded to address incentives to apply for a CPP. This has the key advantage that it is far simpler than the proposal recommended by Dr Lally, while completely addressing the incentive problems raised by the Commission.

Beyond 2020, an alternative option to create greater alignment between the DPP and CPP cost of capital would be to adopt a trailing average or indexed approach to the cost of debt. The extent to which this would address any incentive problems would depend on the implementation of the trailing average or indexed approach – and in any case would only do so for the debt component of the cost of capital.

## 4.1 Incentives created by a changing cost of capital

Dr Lally's report starts by identifying incentive problems associated with the cost of capital either increasing or decreasing after the DPP reset. It is worth noting that there are two differentiable incentives arising from the cost of capital that would be set under a CPP – the incentive to apply for a CPP and the incentive to invest:

- incentives to apply for a CPP are affected by differences between the Commission's allowed cost of capital at the beginning of the regulatory control and what it would allow if the cost of capital were re-estimated mid-period; and

[35] Commerce Commission, *Input methodologies review: Update paper on the cost of capital topic*, 30 November 2015, pp 29-31

[36] Martin Lally, *Complications arising from the option to seek a CPP*, 18 September 2015, pp 17-18.

- incentives to invest are affected by differences between the Commission's allowed cost of capital over the life of the asset, and the actual cost of capital faced by suppliers over that same period.

Dr Lally's primary recommendation is that the incentives to apply for a CPP could be addressed by adopting a split form of the cost of capital, using:[37]

- the existing DPP cost of capital to all existing assets and all new assets that were envisaged under the DPP; and
- the new CPP cost of capital to additional investment predicted as a result of the CPP.

This recommendation is targeted at addressing both incentive issues arising from setting a CPP cost of capital. That is, Dr Lally's proposal seeks to address incentives to apply for a CPP while ensuring that incentives to invest in the incremental capital expenditure proposed under the CPP are maintained by using an updated cost of capital.

Dr Lally's secondary and less preferred proposal is that the CPP cost of capital be aligned with the DPP cost of capital. This removes the cost of capital incentives associated with applying for a CPP over the current regulatory control period, since no increase (or decrease) in the cost of capital will be achieved by applying for a CPP.

In our view, Dr Lally's secondary proposal is preferable to his primary recommendation in addressing the immediate incentive issues prior to the next regulatory control period. The split cost of capital proposal involves a commitment to a long term change that will be difficult to unwind later should the Commission wish to introduce a trailing average approach from 2020. It is also likely to be complex to implement. We set out our views on these matters in more detail below.

## 4.2 Implementing the split cost of capital

In our opinion, Dr Lally significantly underestimates some of the potential complexities in implementing the split form of the cost of capital. In particular, his recommendation that the asset base be split glosses over the potential challenge that would arise in distinguishing DPP capital expenditure from CPP capital expenditure. It also does not address what would happen later, once the split had been determined.

Dr Lally's recommended split cost of capital requires that the existing DPP cost of capital be applied to the existing asset base and to capital expenditure that was envisaged under the DPP. However, an updated CPP cost of capital would apply to capital expenditure over and above this level.

We note that Dr Lally has not considered:

- how the Commission might seek to distinguish between capital expenditure envisaged under the DPP and additional capital expenditure allowed under the CPP;
- how the Commission would approach future setting of the cost of capital and whether and how it would seek to realign the cost of capital at some later date, or continue to have a split cost of capital over a longer period; and
- how this recommendation would affect any move to a trailing average that the Commission may be considering or may wish to retain as an option to consider in the future.

These are all issues that, in our view, should be taken into account in determining whether the split form of the cost of capital recommended by Dr Lally should be adopted by the Commission. We consider that they point towards a split form of the cost of capital being difficult to implement and administer, and potentially very difficult to 'close out' should the Commission later decide to adopt a different basis for estimating the cost of capital.

[37] Martin Lally, *Complications arising from the option to seek a CPP*, 18 September 2015, pp 17-18

## 4.3 Investment incentives and present value neutrality

A key benefit claimed by Dr Lally for the split cost of capital, relative to aligning the CPP cost of capital with the DPP cost of capital, is that it would provide appropriate investment signals for incremental capital expenditure proposed under the CPP over and above that proposed under the DPP. In our view, the extent to which this is true is likely to be limited, and relies on an analysis of incentives that assumes a level of accuracy and precision in cost of capital estimates well beyond what is in practice achieved by the current IMs.

In particular, the ability of the current IMs to estimate a cost of capital that reflects the actual cost of capital applicable for any particular investment decision by a supplier is very limited. Capital investment decisions are made by reference to the returns that will be delivered by the regulatory regime over many periods, rather than the immediate horizon of the current price control period. Recommending an approach that increases the complexity of the regulatory framework, founded on an assumption that the allowed cost of capital will be aligned with actual costs, risks adding costs and complexity without achieving any benefits.

Dr Lally's analysis operates under a framework in which the current approach under the IMs for determining the cost of capital provides compensation that is present value neutral over the regulatory control period – matching the cost of capital that could be achieved by suppliers over the same period. However, this framework for analysis does not reflect reality.

In the case of the cost of equity, suppliers cannot fix their cost of equity at the level allowed by the current IMs. More generally, the basis for estimating the cost of equity under the IMs is not designed to, and likely does not, provide reliable near term forecasts of the cost of equity. The IM allowance for the cost of equity will not therefore be present value neutral over the regulatory control period, or over any subset of the regulatory control period, except by chance.

In relation to the cost of debt, the allowed cost of debt calculated under the IMs during the present DPP could only be achieved by suppliers if they were to issue the entirety of their debt portfolio for a five year period immediately prior to the beginning of the regulatory control period. This is because, for the majority of businesses, the IMs allows a five year cost of debt, of which neither the risk free rate or the debt premium is indexed (or updated each year within the regulatory control period) and does not allow any transactions costs for interest rate swaps.[38]

However, as explained in section 3.1.1 above, this assumed behaviour does not reflect efficient or prudent debt raising practice for commercial entities. In practice, businesses acting prudently raise debt in a staggered manner so that these debts fall due gradually over time and not all together at once, as the IMs cost of debt allowance assumes. Suppliers may manage their debt portfolio such that:

- only the interest rate swap component of the cost of debt is fixed over the regulatory control period, if the business uses interest rate swaps to manage its regulatory risk; or
- none of the cost of debt is fixed over the regulatory period, if the supplier does not engage in interest rate swap transactions.

Although it might be convenient to make an assumption that suppliers behave in a way that makes the IMs allowed cost of debt align with the actual cost of debt, a more realistic analysis of the incentives for and consequences of applying for a CPP should consider actual debt raising behaviour.

In our view, an assumption that the cost of capital allowance provided over a five year period is present value neutral cannot be sustained. Arguments to the contrary represent, in our opinion, a claim for precision and accuracy of the cost of capital under the IMs going well beyond what can reasonably be asserted. This calls into question the benefits of the split cost of capital proposed by Dr Lally.

[38] The Commission does allow the transactions cost of interest rate swaps as part of the term credit spread differential allowance to debt that is raised for terms of longer than five years.

## 4.4 Alternative proposals to address incentives to apply for a CPP

Although we disagree with Dr Lally's views about the potential costs of his split cost of capital proposal, we consider that there is significantly greater potential in his alternative suggestion that the CPP cost of capital be determined as the existing DPP cost of capital. If the Commission is minded to seek to control incentives to seek a CPP arising from changes in the cost of capital, this appears to be a method for doing so that may impose fewer costs than Dr Lally's primary recommendation.

In particular, Dr Lally's alternative suggestion has the key benefits of:

- simplicity – it does not require capital expenditure to be split between DPP and CPP components;
- certainty – there are significantly fewer unknowns about how it could be implemented compared to the split cost of capital proposal; and
- versatility – unlike the split cost of capital proposal, Dr Lally's alternative suggestion continues to leave open a clear path to a trailing average basis for determining the cost of debt.

Dr Lally also observes that adopting a trailing cost of debt could serve to mitigate incentives to apply for a CPP after 2020, when it could be implemented.[39] We agree that adopting a trailing average and/or an indexed approach could lessen incentives to apply for a CPP. We also note that:

- while adopting a trailing average may address incentives to apply for a CPP, whether it would make any difference to the incentives to invest under a CPP will depend on both its implementation and, more generally, the long term direction and stability of the framework for determining the allowed return on regulatory assets; and
- the Commission is not considering updating the cost of equity component of the overall cost of capital each year and this will continue to give rise to a source of difference between the allowed cost of capital and what a business might expect to obtain under the CPP.

[39] Martin Lally, *Complications arising from the option to seek a CPP*, 18 September 2015, pp 8-9

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