Review of Revised Draft Reset of the 2010-2015 Default Price-quality Paths

Report for Vector Limited

September
2012

Acronyms and Abbreviations

ACCC	Australian Competition and Consumer Commission
AER	Australian Energy Regulator
Capex	Capital Expenditure
CPI	Consumer Price Index
CPP	Customised Price-Quality Path
DPP	Default Price-Quality Path
EDBs	Electricity Distribution Businesses
GWh	Gigawatt Hour
ICPs	Installation Control Points
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
IRIS	Incremental Rolling Incentive Scheme
LCI	Labour Cost Index
IPART	Independent Pricing and Regulatory Tribunal of New South Wales (Australia)
LGCI	Local Government Cost Index
NPV	Net Present Value
OLS	Ordinary Least-Squares
Opex	Operating Expenditure
PPI	Producer Price Index
RAB	Regulatory Asset Base
SFA	Stochastic Frontier Analysis
WACC	Weighted Average Cost of Capital

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Executive Summary

The Commerce Commission (the Commission) has published a Revised Draft Reset of the 2010-2015 Default Price-Quality Paths for electricity distribution businesses (the "draft reset decision"). Vector engaged Castalia to evaluate the Commission's draft reset decision, and to suggest possible improvements to the financial model, econometric analysis, and forecasting assumptions used in the draft reset decision.

We identify several improvements that should be made to the way that the Commission evaluates the current and projected profitability of suppliers. These improvements can be made before a final decision on this reset is released (expected 30 November 2012), and would provide greater confidence that the DPP reset represents a reliable estimate of future supplier costs and revenues. This report also provides recommendations on how to ensure that the processes adopted in the next price reset build greater confidence in the results.

The Commission's approach to forecasting opex penalises high-density, urban networks (and rewards low density, rural networks)

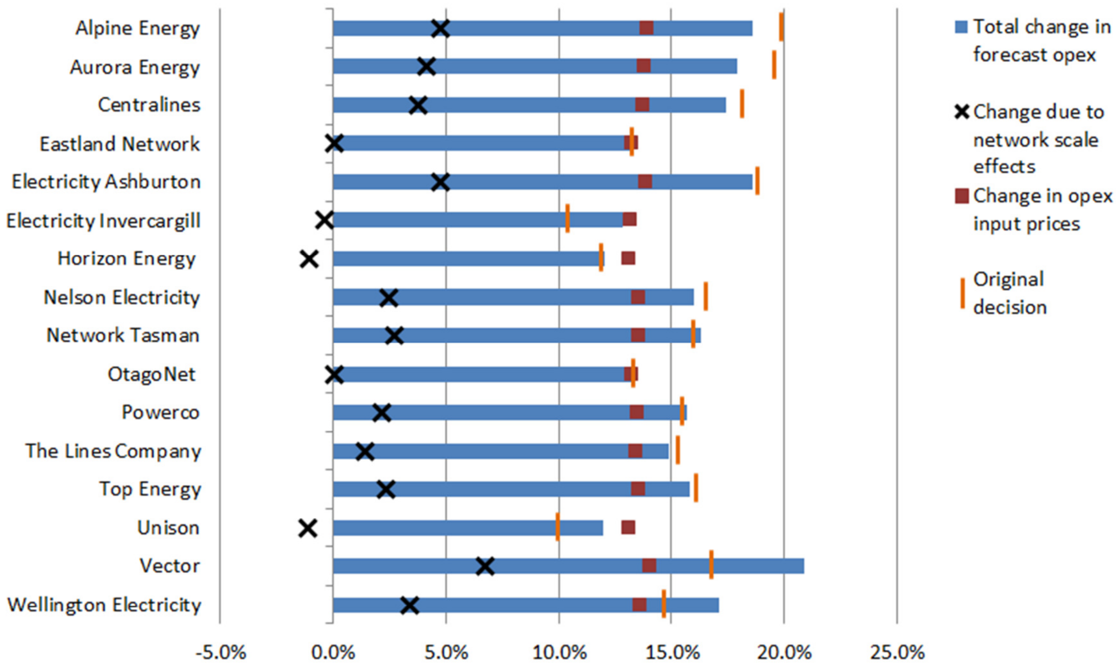
We find that the Commission's approach systematically under-forecasts opex for higher density, urban networks. There are two principal reasons for this.

Firstly, the Commission has failed to apply its estimate of the impact of customer density on non-network opex. The Commission's preferred model includes an explanatory variable that captures network density effects, and the Commission's own forecasts predict that network density will change during the regulatory period. Correcting this apparent oversight would rebalance opex forecasts across the industry. Networks experiencing increasing customer density in coming years due to continued urbanisation (Auckland and Wellington) will have higher opex growth than projected in the Commission's decision. In contrast, areas where customer density is expected to fall (like South Canterbury) will have lower opex growth rates. The overall impact is a 1.0 percent increase in forecast opex across the industry.

Secondly, the Commission has not incorporated a density variable into its preferred model of network opex. In our view, networks with increasing density (due to urban migration) will face higher network operating and maintenance costs per kilometre of circuit because they serve a larger number of customers for any given area. Introducing a density variable (ICPs per km of circuit) to the econometric model of network opex increases the coefficient on the network length variable to 0.988—making the coefficient more consistent with the Commission's expectation of constant returns to scale. The explanatory power of the model also increases when density is included in the model, with the R^2 increasing from 0.81 to 0.88.

We again find that including a density variable increases network opex growth rates in urbanising areas, while reducing growth rates in other areas. Figure ES.1 compares the resulting opex growth rates by supplier with the Commission's decision. The overall impact of applying the density variable to both network and non-network opex forecasts is a 1.4 percent increase in the opex forecasts across the industry.

Figure ES.1: Effect of Network Density Variable on Opex Growth Rates



Note: Effects shown include adding the impact of changes in density to network and non-network opex

Additional data and analysis is needed to ensure that the Commission's opex forecasts are robust and unbiased

The dataset used by the Commission to establish the relationships for forecasting opex is based on two years of data only. The reason for this limited time series is that the Commission specifies different econometric models for network and non-network opex. For the reasons presented above, we believe that both of these components of opex are driven by circuit length and customer density.

Removing the distinction between network and non-network opex would allow the Commission to expand the dataset used to derive econometric relationships. In our view, increasing the data set by using a longer time period would improve confidence in the results. Ideally, the econometric model for total opex would draw on information disclosures provided since 2003/04. However, a series break appears to exist in the data series for total controllable opex between 2007/08 and 2008/09 (this series break should be investigated by the Commission). In our view, incorporating even one year of additional data (2008/09) provides more robust results.

Using this larger dataset, we again find a rebalancing of opex forecasts that increases forecast growth in more densely populated networks. The overall impact is a 0.5 percent increase in opex forecasts across the industry.

To ensure the results of the econometric analysis are unbiased, we recommend that the Commission also tests its models for endogeneity. In our view, the variations in opex inefficiency (captured in the error term) could be attributable to business scale effects, which are captured by the explanatory variables modelled by the Commission. This type of correlation would result in biased coefficient estimates, so should be taken seriously by the Commission and carefully reviewed prior to finalising the reset decision.

The Commission's new approach to forecasting constant price revenue growth is not shown to produce better results

In this draft reset, the Commission has used a new approach to forecast constant price revenue growth using econometrics. This approach is a significant departure from industry norms for forecasting demand growth. The practical implementation of the econometrics-based forecasting approach also raises some concerns:

- **The real regional GDP numbers used by the Commission have an unusually high level of volatility.** Large annual fluctuations in GDP in different regions are not explained in the Commission's decision. For example, the Otago region is reported to have experienced an 18.1 percent decline in real GDP in 2012 (favourably affecting Aurora and OtagoNet). At the other extreme, the Canterbury region is reported to have experienced a 7.6 percent increase in real GDP in the same year.
- **Insufficient justification is provided for excluding data points as "outliers".** Outliers should not be excluded from a data set simply because they do not fit with the Commission's predicted views of the relationship between GDP and demand. The Commission should only exclude outliers based on both statistical tests **and** a conceptual basis for believing that there may be problems with the data (such as entry errors or reporting errors).

We recommend that the Commission "reality checks" the results of the constant price revenue growth forecasts against historical demand outturns. This provides an important validation of the results, and responds to criticisms of the Commission's previous demand forecasting approach that have not been resolved through the change in methodology.

The Commission could improve its forecasts by using a multi-year base year and applying consistent inflators

Operating expenditure is inherently variable, with large increases in one year commonly followed by large percentage decreases in the following year. The analysis presented in this report finds that the Commission could reduce this volatility by using a two or more year average approach to setting the base year for forecasting.

Using a multi-year base year approach would also provide stronger incentives for suppliers to reduce their operating costs throughout the regulatory period, and would reduce gaming incentives. Under an approach using a single base year, suppliers have incentives to push costs into that year to increase their forecast opex requirements in future years. A multi-year base year approach could also be applied to constant price revenue forecasts (although revenue trends exhibit less year on year volatility).

In the draft reset, the Commission has used a number of different indices to inflate costs over the remaining three years of the regulatory period. We agree with the approach that these price indices need to be consistent with the building block cost components, and should therefore be consistent with the inflator used to calculate suppliers' weighted average cost of capital (WACC). However, the Commission's mix of historical and current inflation forecasts creates further inconsistencies—in particular between a historical CPI and the most recent estimates of PPI (changes in producer prices can be thought of as one component of changes in consumer prices). We recommend that these inconsistencies be eliminated by reverting all price inflation forecasts back to those available in September 2009.

What do these findings mean for the reset decision?

This report identifies a number of actions the Commission should take to improve the accuracy, and consistency of the decision to reset prices. In summary, we recommend that the Commission:

- Applies the parameter estimate for customer density when forecasting non-network opex, and incorporates a customer density variable into its econometric model of network opex
- Investigates the volatility in real regional GDP growth, and clarifies why the growth rates used for 2012 are so variable between regions. If the volatility cannot be addressed, then the Commission should consider using national GDP growth data to forecast revenue growth
- Compares the forecasts of constant price revenue growth with a historical time series of demand from different customer groups, and explains why the approach adopted by the Commission produces better results than a simple demand forecasting build-up from different customers
- Explains why it believes that particular data points are outliers and should be excluded from the analysis of constant price revenue growth (based on more than the results of statistical tests alone)
- Reports the results of its econometric analysis with and without any excluded outliers
- Considers an averaging approach for establishing an accurate benchmark of base year opex and supplier revenue, rather than using a single year from which to forecast opex and constant price revenue
- Uses the CPI, LCI and PPI forecasts available in September 2009 to maintain consistency across inflators.

These recommendations all focus on technical issues of modelling and forecasting, and all can be adopted for the final reset decision expected in November 2012. This report also provides recommendations on processes for the next price reset to build greater confidence in the results. Specifically, we consider that the Commission should ensure that supplier data is verified before releasing a draft reset decision, and should carry out pre-consultation on the approaches to forecasting and the financial model before a draft reset decision is released.

1 Introduction

The Commerce Commission (the Commission) has published a Revised Draft Reset of the 2010-2015 Default Price-Quality Path (DPP) for electricity distribution businesses and gas pipeline businesses (the "draft reset decision"). Vector engaged Castalia to evaluate the Commission's draft reset decision, and to comment on possible improvements to the financial model, econometric analysis, and forecasting assumptions used in the draft reset decision. The views expressed in this report are Castalia's, and do not necessarily reflect the views of Vector.

This report focuses in particular on the approaches used by the Commission to evaluate the current and projected profitability of suppliers. This report is structured as follows:

- Section 2 reviews the approach to forecasting operating expenditure, and suggests ways to improve the robustness of the econometric analysis carried out by the Commission
- Section 3 analyses the Commission's approach to forecasting constant price revenue growth
- Section 4 reviews other areas of the Commission's modelling, and identifies two modelling choices that can have a significant impact on the forecasts—the selection of a base year and the use of inflators
- Section 5 comments on the cash flow timing assumptions proposed by the Commission for this price reset
- Section 6 evaluates whether additional allowances for the DPP would be appropriate to overcome forecasting error
- Section 7 concludes by offering suggestions on how the process for making decisions on price resets could be improved before the start of the 2015-2020 regulatory period.

2 Forecasting Operating Expenditure

The Commission has used econometrics to forecast the rate of growth in operating expenditure for each supplier over the regulatory period (Appendix D of the draft reset decision). The validity of any econometric approach rests on the ability of the specified model to estimate robust relationships between key cost drivers and the costs incurred by suppliers. In this section, we identify areas where we believe that the Commission's analysis of operating expenditure does not achieve this outcome—most notably in failing to account for the impact that customer density has on operating expenditure.

We adopt the recommendations for econometric analysis made in the recent ACCC paper on "Benchmarking Opex and Capex in Energy Networks"[1]. At pages 82-83 of that report, the ACCC sets out some important steps for appropriately using econometrics to analyse costs that we use to structure our analysis of the Commission approach:

- **Identifying variables that explain cost differences (Section 2.1).** The Commission's analysis rests on the assumption that changes in network opex can be explained solely by changes in circuit length. This is at odds with our understanding of the economics of network businesses, and differs from regulatory practice applied overseas when analysing opex cost drivers.
- **Maximising the value of available data (Section 2.2).** In order to separately analyse network and non-network opex, the Commission restricts its dataset to the last two years (2009/10 and 2010/11). In our view, the value of modelling separate cost drivers for network and non-network opex is outweighed by the cost of sacrificing available data on total controllable opex.
- **Interpreting the results of opex econometrics (Section 2.3).** An important shortcoming of conventional econometrics for understanding the costs of network businesses is that it does not separate the impact of random error from inefficiency (the entire error term is assumed to be inefficiency). This assumption may not hold for EDBs in New Zealand, where the relative efficiency of suppliers may be correlated with scale (used as explanatory variables). This type of correlation would result in biased estimates of the impact of scale variables in the Commission's OLS regressions.

2.1 Identifying Variables that Explain Cost Differences

Good econometric analysis relies on accurately identifying the factors that explain differences in the dependant variable. Identifying the right explanatory variables needs to be based on more than statistical significance alone—in this case, the explanatory variables used to forecast costs need to align with industry knowledge on the factors that actually drive those costs. Without a conceptual model of cost drivers, econometric analysis risks identifying statistically significant variables that are correlated with opex purely by chance.

Correctly applying the econometric model specified for non-network opex

To project non-network opex, the Commission has specified an econometric model that contains three explanatory variables: circuit length, GWh supplied, and ICPs per kilometre of circuit length (see Table D.1 of the draft reset decision). The coefficients on all three explanatory variables are all found to be statistically significant. However, the

[1] ACCC (2012) "Benchmarking Opex and Capex in Energy Networks". Available online at: http://www.accc.gov.au/content/item.phtml?itemId=1054590&nodeId=219f60511860051852d2f061523263cd&fn=ACCC-AER%20working%20paper%206%20-%20benchmarking%20energy%20networks.pdf

Commission has not used the coefficient on the density variable (ICPs per km of circuit) to project non-network opex, despite it being part of the preferred model.

The failure to apply the density variable coefficient could either be an oversight, or could be based on an assumption that density will not change over the remainder of the regulatory period. However, the Commission's own projections model shows that density will change—the model forecasts changes in the number of ICPs on each network for the regulatory period (based on population growth), and also forecasts changes in circuit length (based on historical trends). Simply subtracting the percentage growth in circuit length from the percentage growth in ICPs provides a forecast of future customer density that is consistent with the other projections made by the Commission.

For example, in the Auckland region, ICPs are forecast to grow by 1.5 percent each year over the regulatory period, while Vector's circuit length is expected to increase by 0.5 percent. This means that customer density will increase by 1.0 percent per year. Applying this percentage increase in density to the current level of customer density provides a forecast of ICPs per kilometre of circuit over the regulatory period. Customer density in some network areas is expected to fall over the regulatory period. For example, in South Canterbury, Alpine Energy's population is forecast to grow by 0.1 percent each year, while circuit length is projected to grow by 1.6 percent per year. The Commission therefore expects density to decline by 1.5 percent per year for Alpine Energy.

Figure 2.1 illustrates the different network density characteristics of non-exempt EDBs (using the Commission's opex projection models). A clear distinction exists between urban and rural networks—with only four EDBs having current density of more than 20 customers per kilometre of circuit (on average). The urban EDBs are Electricity Invercargill, Nelson Electricity, Vector, and Wellington Electricity. Density on these networks is also projected by the Commission to grow at higher rates than in rural networks. On average, customer density in urban networks is expected to grow at 0.60 percent per year during the regulatory period, and is expected to decline by 0.35 percent per year in rural networks.

Figure 2.1: Density Characteristics of Non-exempt EDBs

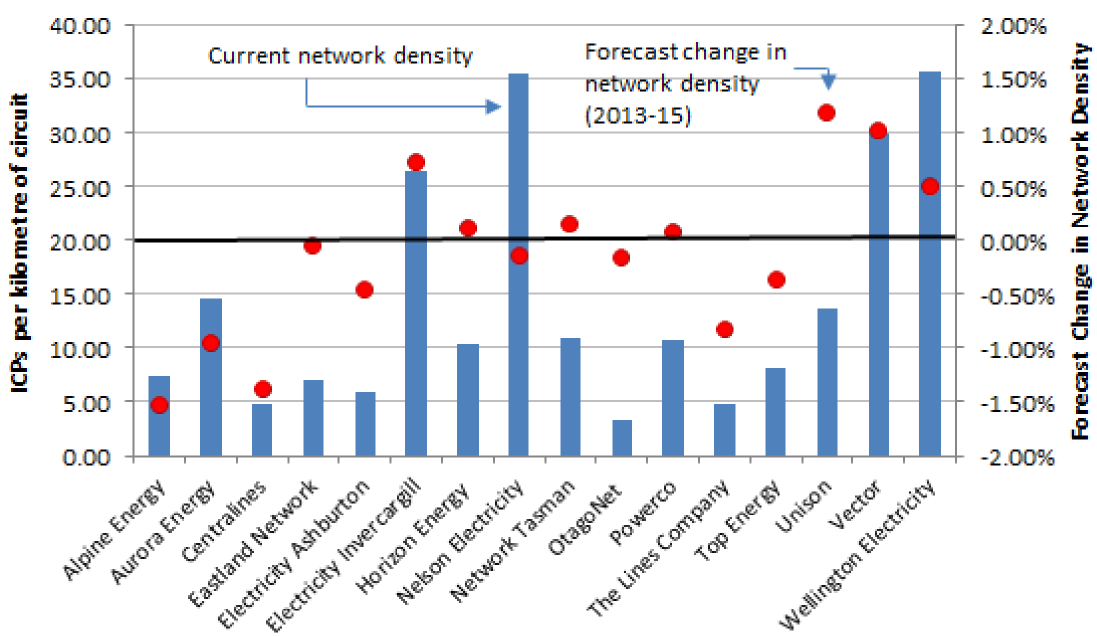
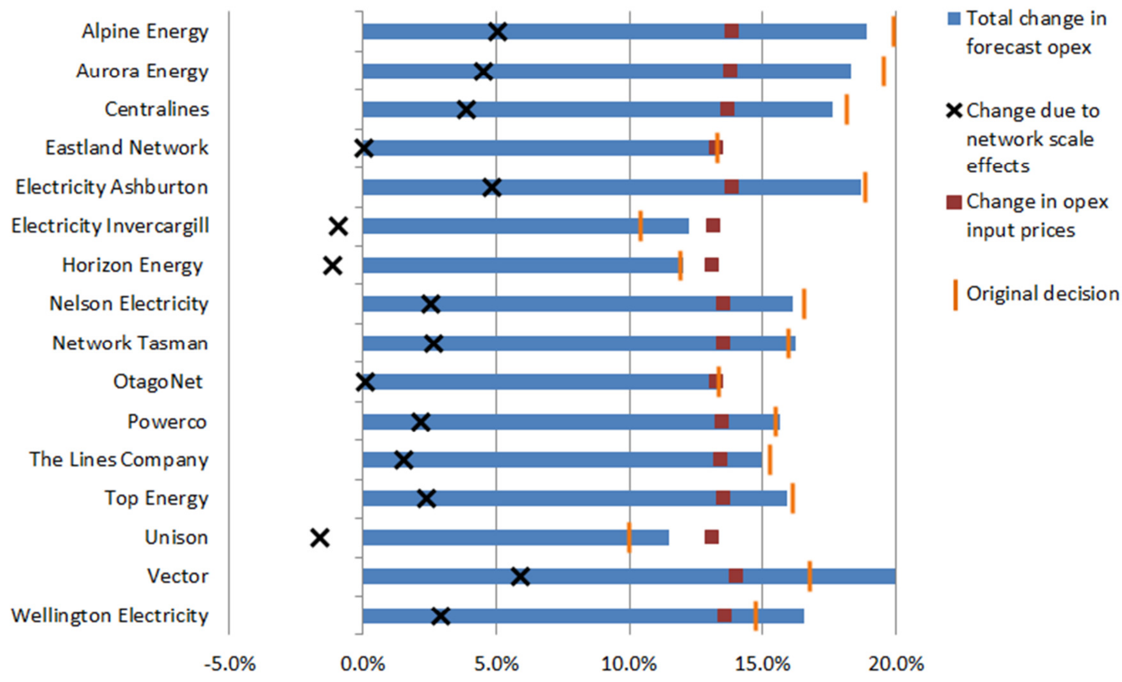


Figure 2.2 shows the impact that using the density variable coefficient estimated by the Commission has on projections of non-network opex for each supplier. Not surprisingly, networks that will experience increasing customer density in coming years due to continued urbanisation (Auckland and Wellington) are projected to have higher opex growth than projected in the Commission's draft reset decision (shown on the graph by the vertical line for each supplier). In contrast, areas where customer density is expected to fall (like South Canterbury) have lower opex growth. The overall impact is a 1.0 percent increase in the opex forecasts across the industry.

Figure 2.2: Effect of Non-network Density Variable on Opex Growth Rates



Source: Castalia analysis of Commerce Commission draft reset decision

In addition to having the benefit of fully applying the Commission's preferred model, this approach also better aligns opex forecasts with the Commission's treatment of constant price revenue growth (discussed further in Section 3). Chart A.4 of the draft reset decision shows that the Commission expects urban areas (particularly Auckland and Wellington) to grow their revenues due to an increase in population. In reality, these new users will impose additional costs on suppliers as well as being a source of revenue. Applying a density measure to opex forecasts appropriately accounts for these costs and better aligns cost forecasts with expectations of customer growth. If the Commission does not apply a density variable then the current and projected profitability of urban suppliers will be over-estimated, resulting in excessive (downward) P_0 adjustments that undermine supplier's ability to earn normal returns.

We also note that achieving a closer alignment between opex forecasts and constant price revenue growth forecasts is more consistent with the Commission's previous approach to forecasting opex (in the superseded July 2011 price reset decision). In its previous draft price reset decision the Commission directly linked opex to revenue growth, suggesting that the Commission should prefer a forecasting approach that achieves a better (though not complete) alignment between the two forecasts.

Improving the econometric model specified for network opex

To project network opex, the Commission has specified an econometric model that contains one explanatory variable: circuit length. The draft reset decision does not explain in detail why circuit length is thought to be a good predictor of network opex, although the Commission states that statistical tests indicate that the model does not have omitted variables (see paragraph D.16 of the draft reset decision).

In our view, circuit length alone is unlikely to provide a good prediction of future network opex. We believe that it is important to also account for the impact that network density has on network opex (as well as non-network opex). The relationship between density and network opex is intuitive: for any given length of circuit, increasing customer numbers will increase the probability of technical issues arising, and therefore increases the need for preventive and corrective maintenance. More specifically, as highlighted in Vector's submission:

- In urban areas, customer growth often occurs within the same geographic footprint through a process of subdividing properties. This leads towards higher density housing
- An increase in the number of customer premises within a geographic area will increase the number of assets (transformers, switchgear, etc) per kilometre of circuit
- Because all assets require maintenance, total network operating expenditure is driven by the total number of assets on a network. More equipment per kilometre of circuit therefore means more equipment to maintain, and higher network opex.

Other econometric models of network opex commonly incorporate measures of customer density. The ACCC review (at Table 4.1) contains a summary of seven econometric models used in the academic literature to benchmark network costs. Some models focus on opex only, while others model total expenditure (capex and opex). We note that all of the models contain measures of both network length and customer numbers or density.

Table 2.1 below summarises the impact of including the density variable included in the preferred model for non-network opex (ICPs per kilometre of circuit) in the econometric model for network opex. All of the coefficients used to project future opex are statistically significant in both models. The introduction of a density variable increases the coefficient on the network length variable slightly—making the coefficient even more consistent with the Commission's expectation of constant returns to scale. The explanatory power of the model increases when density is included in the model, with the R^2 increasing from 0.81 to 0.88.

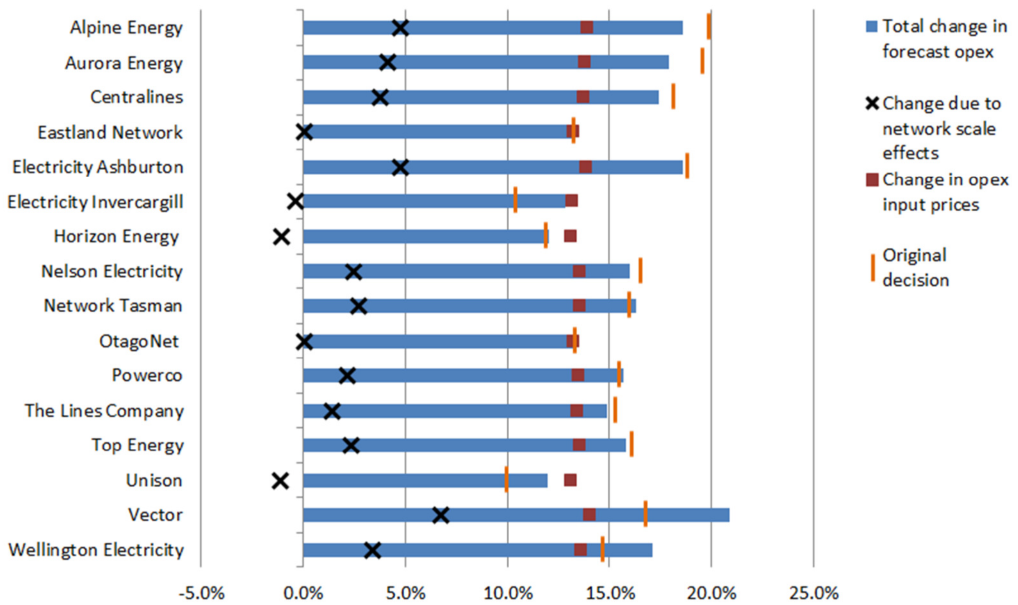
Table 2.1: Econometric Models for Network Opex

Item	Commission's Preferred Model	Castalia's Preferred Model	Comments
ln(network length for supply)	0.948***	0.988***	Network length is highly significant in both models and consistent with expectation of constant returns to scale
ICPs per km of circuit		0.013***	Density variable has high statistical significance
Constant	0.563	-0.130	
Adjusted R^2	0.81	0.88	Density variable improves the explanatory power of the model
F-statistic	270	228	Both models have good overall statistical validity
N	57	57	

Notes: *** significant at the 1% confidence level. Models have been estimated using heteroscedasticity-robust standard errors. Sensitivity excluding outliers omits data for Nelson in 2009/10 and Vector in 2009/10 and 2010/11. Stata code for the Castalia model is provided in 7Appendix A.

Figure 2.3 shows the impact that including a density variable has on the growth rates used to project opex by the Commission. Just as with non-network opex, the use of a density variable tends to increase the opex growth rates in urbanising networks (Auckland and Wellington), while reducing growth rates in other areas. The overall impact is a 1.4 percent increase in the opex forecasts across the industry.

Figure 2.3: Effect of Network Density Variable on Opex Growth Rates



Source: Castalia analysis of Commerce Commission draft reset decision

Note: Effects shown include adding the impact of changes in density to network and non-network opex (i.e. effects are cumulative with effects shown in Figure 2.2 above).

2.2 Maximising the Value of Available Data

The Commission has chosen to exclude data from before 2009/10 because it does not have a breakdown of network and non-network opex for those years (see paragraph D.11 of the draft reset decision). The Commission claims that the drivers of network and non-network opex are likely to be different. In our view, the Commission's forecasts would be improved by having a single model econometric model for total controllable opex. This approach has several benefits. It:

- **Simplifies the modelling**
- **Eliminates the risk of errors due to different interpretations of what counts as network and non-network opex**
- **Expands the sample size.** While the relationships between opex components and scale variables are statistically significant for the two years covered by the Commission's analysis, this does not mean that those relationships are likely to hold for future opex. More confidence in these relationships would be gained by having a larger dataset—either through adding information on more suppliers or considering a longer time period
- **Is consistent with expectations of the drivers of opex.** As discussed above, we consider that all opex (network and non-network) is driven primarily by the geographic reach of the network (circuit length) and customer density (ICPs per kilometre of circuit).

From our review of the data provided through information disclosures, the total controllable opex variable appears to have a series break from 2007/08 to 2008/09—each supplier's opex decreases by around 50 percent between those years. This may be due to different recording of particular cost components, such as pass-through costs. This means that only data from 2008/09 onwards can be used in our analysis, providing one extra year of data compared with the Commission's approach (increasing the number of observations from 57 to 84). To expand the dataset further, we recommend that the Commission investigates the reasons for the apparent series break in total controllable opex, and whether this break can be removed (providing a further four years of data and a total of more than 220 observations).

Table 2.2 shows the impact of using available data on total controllable opex from 2008/09 to 2010/11 on the coefficients on scale variables. For this analysis, we have tested the impacts of using the two variables that we see as most relevant for opex—circuit length and customer density—as well as a model that incorporates the additional variable included in the Commission's preferred model of non-network opex (electricity supplied to ICPs). All coefficients are statistically significant in both models, and the explanatory power of the models is very high.

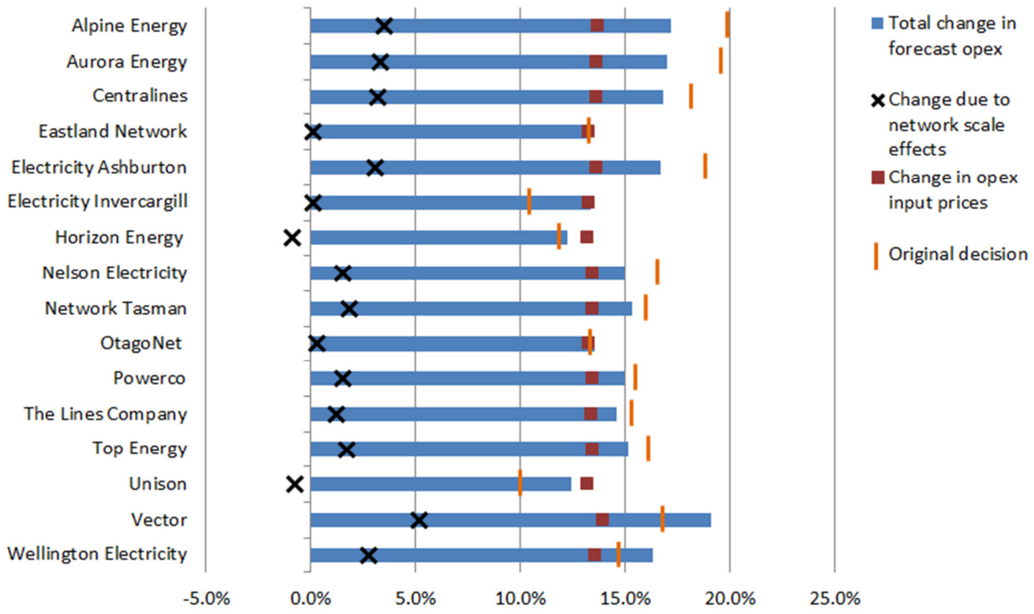
Table 2.2: Econometric Models for Total Opex

Item	Castalia's Preferred Model	Alternative Model	Comments
ln(network length for supply)	0.898***	0.608***	Network length is highly statistically significant in both models, and more consistent with constant returns to scale in the preferred model
ln(electricity supplied to ICPs)		0.275***	
ICPs per km of circuit	0.042***	0.024***	Density variable is highly statistically significant in both model
Constant	1.309***	2.162***	
Adjusted R^2	0.91	0.92	No real difference in the explanatory power of the models
F-statistic	596	382	Both models have good overall statistical validity
N	84	84	

Notes: *** significant at the 1% confidence level. Models have been estimated using heteroscedasticity-robust standard errors. Stata coding for the Castalia models is provided in 7Appendix A

Figure 2.4 shows the impact that a total controllable opex regression has on the projected growth rates for future opex. The coefficient on the density variable means that areas forecast to experience population growth without large increases in size of their networks (Vector and Wellington Electricity) all have higher opex growth rates. The overall impact is a 0.5 percent increase in the opex forecasts across the industry.

Figure 2.4: Effect of Total Opex Econometrics on Opex Growth Rates



Source: Castalia analysis of Commerce Commission draft reset decision

This analysis further supports our view that the Commission's approach is likely to systematically under-forecast opex for higher density, urban networks.

2.3 Interpreting the Results of Opex Econometrics

The econometric approach used by the Commission to analyse opex will produce biased estimates if business-specific inefficiency is correlated with explanatory variables in the model. This problem is known as endogeneity. The ACCC report on benchmarking capex and opex notes this as a common concern when using econometrics for network cost analysis. The Commission describes endogeneity as an issue for its modelling of constant price revenue (see paragraph G.48 of the draft reset decision), but does not discuss its implications for the opex econometrics.

In our view, it is entirely plausible that variations in opex inefficiency (captured in the error term) are attributable to business scale, captured by the explanatory variables modelled by the Commission. The absence of independence between the error term and the independent variables would call into question the use of ordinary least-squares (OLS) estimators commonly used for econometric analysis, and would require the Commission to adopt other approaches (such as two-stage least squares regressions using instrumental variables).

Given the prospect of biased coefficient estimates, we believe that the Commission should evaluate the issue of endogenous variables further and formally test for endogeneity (as it does for omitted variables and heteroskedascity). Endogeneity can be evaluated using the Durbin-Wu-Hausman test (through the ivreg2 command in Stata). However, this test requires reasonable instrumental variables to substitute for the variable suspected to be endogenous, and all of the scale variables included in the Commission's dataset potentially suffer from the problem of endogeneity.

There are manual approaches for investigating endogeneity that the Commission could use, such as:

- Running the first stage regressions and saving the residuals
- Including the first stage residuals as additional regressors in the main equation
- Testing the joint significance of the first stage residuals.

Apart from using instrumental variables, the Commission could overcome the endogeneity problem by adopting more data intensive statistical methods, such as the Stochastic Frontier Analysis (SFA) (for a description of SFA see chapter 5 of the ACCC report). We understand that adopting SFA analysis at this stage in the process of resetting prices for the DPP may be difficult due to time constraints. However, it is important for the Commission to examine this issue to ensure that parameter estimates resulting from its econometric analysis of opex are unbiased (for this reset and future starting price adjustments).

3 Forecasting Constant Price Revenue Growth

The Commission has directly forecast constant price revenue growth over the remainder of the regulatory period by separately considering the drivers of revenue growth from residential consumers and industrial/commercial consumers. This approach is a major change from the Commission's previous approaches for forecasting demand, and has not been shown by the Commission to deliver superior results.

We have several reservations about the approach used to forecast constant price revenue growth. At a conceptual level, the approach differs from industry norms for demand forecasting and is not as intuitive as directly forecasting the different components of demand: fixed charges, maximum demand, and energy usage. We have also identified some issues in how the approach is applied—in particular that an unusual level of volatility in real regional GDP numbers influences the forecasts of revenue growth from industrial and commercial customers, and that the exclusion of outliers from the analysis has not been adequately explained.

3.1 General Comments on Approach to Forecasting Demand

The approach used by the Commission to forecast constant price revenue growth is not intuitive. The Commission is using revenue to proxy for demand growth—and should explicitly relate the approaches used to forecast revenue growth to other demand forecasts to test for the appropriateness of the techniques used.

New forecasting approach is not shown to produce better forecasts

The Commission was criticised for the demand forecasts presented in the July 2011 draft price reset decision. However, most of the criticisms were based on the selection of datasets, rather than the way that the demand forecasts were built-up. In our view, the Commission could have responded to those criticisms without fundamentally changing its approach. For example, the Commission itself notes problems in achieving consistency between the GDP forecasts used to forecast the different components of total demand. This issue could have been corrected relatively simply by using a single estimate in building up demand forecasts for price resets.

A consistent theme emerging from the submissions on the July 2011 draft price reset decision was that the resulting demand forecasts bore little relationship with historical growth trends. In our view, the approach used in current draft reset decision does not respond to this concern. The starkest example is the forecast of constant price revenue growth for Electricity Ashburton—revenue is projected to grow by more than 3.5 percent over the next three years, primarily due to high forecasts of real regional GDP growth. It would be useful to know whether Electricity Ashburton (and other suppliers) has ever achieved the constant price revenue growth predicted by the Commission in the past.

We therefore recommend that the Commission compares the forecasts of constant price revenue growth with a historical time series of demand from different consumer groups, and explains why the approach adopted in the draft reset decision produces better results than a simple demand forecasting build-up from different consumers.

Real regional GDP numbers have unexplained volatility

In reviewing the Commission's forecasts of constant price revenue growth, we have noticed that the recorded changes in real regional GDP for 2012 are highly volatile. For example, the Otago region is reported to have experienced an 18.1 percent decline in real GDP in 2012 (favourably affecting Aurora and OtagoNet). At the other extreme, the

Canterbury region is report to have experienced a 7.6 percent increase in real GDP. While the Canterbury earthquakes will have had an impact on GDP forecasts, we would be surprised if the networks in the region (Alpine Energy and Electricity Ashburton) have grown their revenues by the projected levels during that year.

To highlight the unusual level of volatility in the real regional GDP estimates for 2012, Table 3.1 presents statistics on the real regional GDP growth estimates used by the Commission in the draft reset. The variability of actual growth numbers is significantly greater than for forecasts—with the standard deviation of GDP growth in different regions being more than five times greater for 2012 than for the forecast years 2013 to 2015. The range of outcomes for GDP growth in 2011 and 2012 is considerably larger for the forecast years. Although regional changes in GDP will fall both above and below national changes in GDP, the level of regional variation shown in the forecasts for 2013 to 2015 is more consistent with our expectations of actual differences in the economic performance of different regions.

Table 3.1: Summary Statistics for Real Regional GDP Growth

Year	Real Regional GDP Growth Mean (unweighted)	Real Regional GDP Growth Standard Deviation	Real Regional GDP Growth Maximum	Real Regional GDP Growth Minimum
2011	1.6%	0.035	8.6%	-4.3%
2012	-3.1%	0.073	7.6%	-18.1%
2013 (f)	1.8%	0.013	3.4%	-0.7%
2014 (f)	1.3%	0.009	2.9%	-0.2%
2015 (f)	1.6%	0.008	3.0%	0.0%

Note: (f) indicates a growth forecast, rather than an actual growth estimate

The Commission has not provided us with access to the real regional GDP forecasts because this information has proprietary value to NZIER. This is clearly not ideal from the standpoint of regulatory transparency. Putting that issue to one side, we understand that NZIER's regional GDP estimates and forecasts are based on allocating national GDP to each industry, and then allocating industry GDP to each region based on regional share of employment in each industry. The key assumption is therefore that there is no regional variation in labour productivity within a given industry, which may not hold if there are specific changes within an industry in a particular region (such as large scale redundancies aimed at improving productivity).

We recommend that the Commission investigates the volatility in real regional GDP growth highlighted in Table 3.1, and clarifies why the growth rates used for 2012 are so extreme. If the volatility in regional GDP estimates cannot be addressed, then the Commission should consider using national GDP growth data. Although national GDP figures will provide the Commission with a less tailored forecast of demand growth, they are the only estimate of economic growth that is not subject to simplifying assumptions[2].

[2] We note that Statistics New Zealand previously maintained a data series for regional GDP, but discontinued this series in 2003. Parties other than NZIER also provide estimates of regional economic activity, but generally use regional employment data to derive GDP, and therefore also assume constant labour productivity within a sector across different regions.

3.2 Econometric Relationship between Industrial/Commercial Demand and Real Regional GDP

The Commission has used econometrics to model how demand from industrial and commercial consumers changes with changes in real regional GDP. We are concerned that the implicit assumptions in this analysis may not be valid. We also believe that the Commission needs to be more careful when excluding data points that are identified through statistical tests as outliers.

Implicit assumptions in modelling constant price revenue from industrial and commercial customers

The econometric analysis of constant price revenue growth makes two important implicit assumptions, which we believe should be made explicit and formally tested:

- **That there will be no change in the mix of revenue received from industrial and commercial customers through fixed charges, demand charges, and energy charges.** We see legitimate reasons to question this implicit assumption. The Electricity Authority actively promotes a move towards more demand-based charging under the distribution pricing principles (originally drafted by the Commerce Commission). Principle (a)(iii) requires distributor prices to signal the economic costs of service provision by signalling, to the extent practicable, the impact of additional usage on future investment costs. The economic costs of distribution services are generally driven by peak demand requirements, meaning that under the pricing principles distributors should shift towards demand-based charges and away from energy-based charges. We understand that the Lines Company has already implemented a peak pricing approach, and other regulated businesses may follow, depending on how the Authority decides to implement the principles and enforce compliance.
- **That the relationship between GDP and industrial and commercial revenue is steady over time.** Again, we see legitimate reasons to challenge this assumption. A recent report by MoBIE suggests that demand per dollar of GDP has fallen by around 1 percent per annum from 2000 to 2011.[3] This report also suggests that the overall link between energy use (not just electricity) and GDP is more like 1:3 (rather than 1:2 as found by the Commission in the draft reset decision).

These implicit assumptions highlight the challenges of using econometrics to forecast future growth in revenue. Past relationships between variables may not hold for the future, particularly when a clear trend exists in the relationship. We recommend that the Commission compares the results of the econometrics with a historical time series of demand from different consumer groups, and explains why the forecasts that rely on econometrics produce better results.

Further analysis is required to justify the exclusion of outliers

Our other concern with the econometrics for constant price revenue growth is that "outliers" are excluded based on statistical tests alone. The Commission uses four outlier tests, and excludes data points that fail three out of the four tests. However, we understand that three of the tests are based on the Dffits test and the fourth test is a leverage test. Econometric theory is clear that outliers should only be excluded if a

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[3] http://www.med.govt.nz/sectors-industries/energy/pdf-docs-library/energy-data-and-modelling/publications/changes-in-energy-use/changes-in-energy-use.pdf

plausible explanation or hypothesis is provided on why the data points identified are different from the rest of the sample (for example, due to entry or recording error or if the data points are thought to be drawn from a different sample).[4]

The Commission does not attempt to explain why excluded data points might be different, and instead relies on "improvements to the robustness of the model" as the grounds for excluding data points. Removing data points that are further away from the line of best fit than the average will improve some of the statistical properties of the model. However, excluding these observations without explaining why this is appropriate is not good practice.[5]

In our view, to legitimately exclude outliers from the econometric analysis of constant price revenue growth, the Commission should apply the following approach:[6]

> *Only as a last resort should outliers be deleted, and then only if they are found to be errors that can't be corrected or lie so far outside the range of the remainder of the data that they distort statistical inferences. When in doubt… report model results both with and without the outliers to see how much they change.*

To respond to these concerns, we recommend that the Commission:

- Explains why it believes that particular data points are outliers (not simply based on the results of statistical tests)
- Reports the results of its econometric analysis with and without the excluded outliers.

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4 See for example Wooldridge, J (2009). Introductory Econometrics: A Modern Approach at page 325.

5 http://www.sonoma.edu/users/c/cuellar/econ317/Outliers.pdf

6 University of Oregon, Dealing with 'Outliers': Maintain Your Data's Integrity. Available online at http://rfd.uoregon.edu/files/rfd/StatisticalResources/outl.txt

4 Improving Other Forecasting Approaches

Outside of the econometric forecasting techniques used by the Commission, we believe that there are ways to improve the approach to forecasting to achieve more reliable forecasts. In this section, we raise two specific concerns with the Commission's approach to forecasting:

- The use of a single base year (2009/10) for forecasting results in volatile projections, particularly for operating expenditure; and
- The use of price inflators defined at different times lead to an internal inconsistency in the Commission's forecasts.

We provide suggestions for how to improve the Commission's forecasting approaches to resolve these concerns.

4.1 Base Year Selection

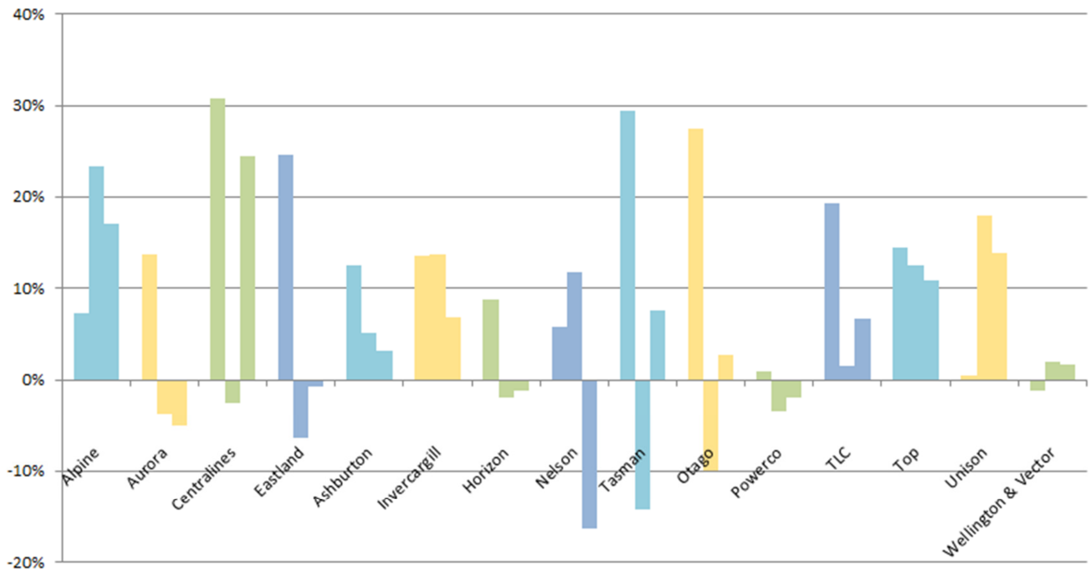
The Commission uses 2009/10 data as a base year to forecast operating expenditure and constant price revenue. This approach will only be conceptually valid if 2009/10 represents an average level of annual expenditure (at least for most suppliers). We believe that there are reasons to question the validity of the use of a single base year in the draft reset decision, and that using a longer time period to establish a base level of annual expenditure may be appropriate.

There are clearly trade-offs in selecting the period of time used to average operating expenditures. A longer period is more effective at addressing year on year volatility and smooths efficiency incentives over the regulatory period in a similar manner to an incremental rolling incentive scheme (IRIS). A longer period also reduces incentives for businesses to shift costs into the base year. However, a longer period could also result in a less accurate forecast and under-recovery of costs if there has been a step change in operating expenditure during the latter part of the base year period. This is because a multi-year base year approach creates a lag before the change is reflected in forecasts of operating expenditure.

Operating expenditure is highly variable

An analysis of the annual change in real operating expenditure for EDBs over the period from 2008/09 to 2010/11 is shown in Figure 4.1. This suggests a high degree of volatility and variability in supplier opex from year to year—annual changes of more than 10 percent in either direction are relatively common. Large increases in opex are also frequently followed by a large percentage decreases in opex, suggesting that opex requirements may in fact be reasonably stable if a time period of more than one year is used.

Figure 4.1: Annual Change in Total Controllable Opex (real) 2008/09 to 2010/11



Notes: Vector and Wellington Electricity (which became separate entities in 2009/10) are combined in this analysis

The impact of using a single base year in light of this volatility is that some suppliers benefit, while others lose. For example, Nelson Electricity's total operating expenditure increased by 10 percent in real terms from 2008/09 to 2009/10. This increase might reflect a step-change in opex, meaning that the base year provides a valid starting point for forecasting future opex. However, this change could also reflect a random allocation of expenditure to the year 2009/10 reporting year, which would lead to an inflated base for forecasting future opex. In contrast, other EDBs will be punished by a single base year if they happened to have spent less that year due to the timing of their expenditures. For example, Centralines' total operating expenditure decreased by 4 percent in 2009/10 in real terms.

Table 4.1 investigates this issue further by presenting the year on year change in real total controllable opex for each supplier from 2009/10 (the Commission's base year) to 2010/11 (released in the latest information disclosures). Part of each supplier's change will reflect changes in operating efficiency, but changes in efficiency will not explain the entire change. In 2010/11, Nelson Electricity's total controllable opex decreased by 21 percent in real terms from the Commission's base year. This suggests that the 10 percent increase that occurred in 2009/10 was not a "step change" in opex, but is more likely explained by factors that led 2009/10 opex to be overstated (and possibly for 2010/11 opex to be understated). Conversely, Centralines apparent reduction in opex in 2009/10 was more than reversed in the following year (2010/11), with opex increasing by 18 percent in real terms.

Table 4.1: Change in Total Controllable Opex by Supplier 2009/10 to 2010/11

EDB	Total Controllable Opex *		Change (%)
	Commission's Base Year Opex (2009/10)	Latest Information Disclosures (2010/11)	
Alpine	10,119	11,263	11%
Aurora	19,102	17,234	-10%
Centralines	2,558	3,025	18%
Eastland	5,727	5,403	-6%
Ashburton	5,912	5,793	-2%
Invercargill	4,291	4,357	2%
Horizon	6,706	6,295	-6%
Nelson	2,093	1,663	-21%
Tasman	7,259	7,420	2%
Otago	4,850	4,732	-2%
Powerco	56,242	52,373	-7%
TLC	6,701	6,789	1%
Top	11,130	11,724	5%
Unison	25,324	27,382	8%
Wellington and Vector	135,132	130,547	-3%
Total	**303,146**	**296,001**	**-2%**

Note: * For comparison, this table presents total controllable opex reported in nominal terms in information disclosures, converted into 2009/10 dollars.

Part of the volatility in opex may also reflect issues with the source data—such as being prepared on an inconsistent basis year on year as a result of changes in the information disclosure regime (i.e. series breaks). If this is the case, then the same errors and inconsistencies will exist in the econometric relationships that are derived using this data.

There may be valid reasons for the variability in operating expenditure

Assuming that the variability in operating expenditure does not result from data errors, we see several reasons why year on year operating expenditure may reasonably be volatile. These reasons include:

- The balance between the supplier's workforce employed on capital works projects versus routine maintenance projects may have changed
- Severe weather conditions—such as winter storms—may have led to higher expenditure on faults and emergency works in a particular year
- Maintenance activities may have a cyclical element with a timescale of more than one year, resulting in apparent peaks and troughs in opex; or
- The real changes in the cost of services and equipment may vary from the CPI inflator used to convert nominal costs into real 2009/10 costs—for example, if the cost of components is impacted by large variations in world copper prices.

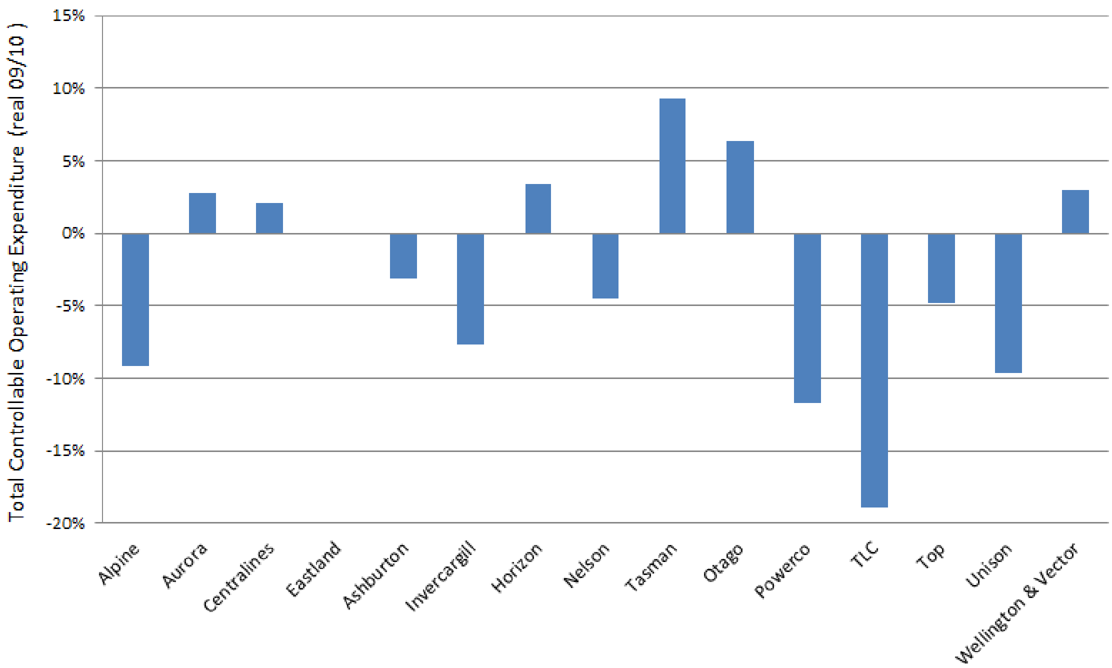
These examples suggest that there can be significant variations in the real level of operating expenditure from one year to the next. The use of a single year as a base for forecasting future operating expenditure therefore risks introducing an arbitrary degree of inaccuracy to the projections because annual expenditure does not capture longer term trends.

Accuracy would be improved by using a multi-year average to establish the base for forecasting

The Commission could improve the stability of operating expenditure forecasts by using an average of between two and five years to set a base operating expenditure allowance, and then applying the forecasting methodology to that base. The average would need to be calculated in real terms—by inflating operating expenditure into 2009/10 values, and then taking a simple average of real operating expenditures over the selected period.

Figure 4.2 shows the change in the base year level of opex that resulting from a two-year average of opex (2008/09 and 2009/10), compared with the Commission's base year opex. This illustrates that most suppliers would be starting from a materially different opex base using an averaging approach rather than a single base year. Overall, this approach would result in a slight reduction in opex across the industry—due to the fact that most suppliers' opex increased in real terms during 2009/10.

Figure 4.2: Change in Opex using Two-Year Average in Operating Expenditure



Note: Total opex reported in nominal terms in information disclosures has been converted into 2009/10 dollars for this analysis

Table 4.2 shows how two and three year average base years compare with the Commission's single base year opex for 2009/10. Incorporating two additional years again changes the base year estimates considerably—Centralines, Eastland Networks, Tasman Networks, OtagoNet JV, and Top Energy would all have opex allowances that are more than 5 percent lower under a three year approach compared with a two year average approach.

Table 4.2: Changes in Opex using Two and Three Year Averages

EDB	Commission's Base Year Opex (2009/10)	Average Opex *		Relative Difference (%)	
		2 years	3 years	2 years	3 years
Alpine	10,161	9,231	8,794	-9%	-13%
Aurora	19,106	19,628	19,107	3%	0%
Centralines	2,559	2,612	2,434	2%	-5%
Eastland	5,979	5,973	5,676	0%	-5%
Ashburton	6,009	5,818	5,607	-3%	-7%
Invercargill	4,402	4,064	3,857	-8%	-12%
Horizon	6,610	6,829	6,724	3%	2%
Nelson	2,093	1,999	1,943	-5%	-7%
Tasman	7,259	7,934	7,549	9%	4%
Otago	4,855	5,162	4,900	6%	1%
Powerco	65,350	57,702	58,367	-12%	-11%
TLC	8,266	6,705	6,380	-19%	-23%
Top	11,133	10,596	10,049	-5%	-10%
Unison	26,102	23,570	23,090	-10%	-12%
Wellington and Vector	131,093	134,963	136,314	3%	4%
Total	**310,976**	**302,786**	**300,792**	**-3%**	**-18%**

Note: * Uses total controllable opex reported in nominal terms in information disclosure, which has been converted into 2009/10 dollars for this analysis

A multi-year average approach would promote incentives for efficiency

Applying an averaging approach for setting the base year in starting price adjustments would provide greater incentives for suppliers to reduce their operating costs throughout the regulatory period. In effect, a multi-year base year approach acts in a similar way as various efficiency benefits sharing schemes used by regulators in Australia[7].

These schemes work on the basis of creating equal incentives for suppliers to pursue efficiency gains during all years of the regulatory reset period. Without such a scheme, suppliers have heightened incentives to pursue efficiency gains in early years of the period (from after the base year) because they retain the benefits of the gains for a longer period of time. In contrast, in the last year of the regulatory period suppliers have little incentive to incur the cost and risk of pursuing efficiency gains because the benefits will only be retained until the end of the year. Evidence from overseas shows how suppliers respond to unstable incentives[8].

The averaging approach to setting the base year creates additional incentives for efficiency because suppliers are permitted to retain some of the efficiency gains into the

7 AER, Electricity Distribution Network Service Providers Efficiency Benefit Sharing Scheme Final Decision, June 2008

8 Castalia report to Vector, "Evidence on the Impacts of Regulatory Incentives to Improve Efficiency and Service Quality" Vector letter to Commerce Commission attachment A, EDB DPP 5 July 2012

next regulatory period. If a full five year average is used then suppliers would retain the benefits of any efficiency gains for the full five years of the regulatory reset period—regardless of when in the period the gains occur.

Use of a single base year may create gaming opportunities at future resets

The use of a single base year in future DPP resets may also create incentives for suppliers to attempt to push costs into that year in order to receive higher opex forecasts. In the case of the next reset for EDBs, we expect the base year to be the fourth year of the current regulatory period (2013/14), because data on the fifth year will not be available when the reset needs to be decided. The multi-year base year approach suggested above would substantially reduce the effect of shifting costs between regulatory years—and would eliminate it entirely if the averaging period was the full five years of the regulatory period.

Similar issues apply to the forecasting of constant price revenue

The Commission also uses 2009/10 as the base year for forecasting constant price revenue. Although revenue is inherently less volatile than operating expenditure, the use of a single base year still risks being affected by one-off factors that cause a change in revenue.

Revenue in any given year will be influenced by factors such as extreme climate events, changes in the consumption of a small number of major customers, and other randomly occurring events (such as voluntary energy conservation campaigns carried out in dry years). Where demand is lower in the base year for whatever reason, the change in constant price revenue needed to equate revenue with costs will be lower. Conversely, if a supplier experience high annual demand during the base year, then constant price revenue will need to fall by a greater amount through the starting price adjustment.

For this reason we recommend that the Commission considers an averaging approach for establishing an accurate benchmark of supplier revenue, rather than using a single base year to forecast constant price revenue.

4.2 Use of Inflators

In this draft reset decision, the Commission has used a number of different indices to inflate costs over the remaining three years of this regulatory period:

- CPI forecasts made in September 2009 are used to revalue the opening asset base and to forecast revenue; and
- Forecasts of the Labour Cost Index (LCI) and Producer Price Index (PPI) made in 2012 are used to escalate operating and capital expenditure forecasts.

This use of inflators from different periods creates inconsistencies

This mix of historic (2009) and current forecasts (2012) has been used by the Commission to maintain consistency between building block cost components and the determination of the cost of capital by the Commission in September 2009. This has been done on the basis that suppliers would have set in place their financing strategies once the WACC was set by the Commission in 2009. We agree with this approach.

However, despite the Commission's intention to maintain consistency, they use 2012 forecasts of LCI and PPI to escalate suppliers' costs in fact creates inconsistency. If consumer price inflation measured by the CPI is largely caused by increases in the costs of production and labour, then the Commission's approach is internally inconsistent. This is because some aspects of future expenditure are derived from 2009 forecasts, while others are derived from 2012 forecasts.

There is some evidence to suggest that PPI causes changes in the CPI because raw materials serve as inputs to the production of intermediate goods, which in turn serve as inputs to the production of final goods[9]. There is also a relationship between the CPI, PPI and LCI, and GDP growth in that all of these indices are used to forecast real and nominal GDP growth. While we understand and support the Commission's approach to using the 2009 CPI forecast to maintain consistency with the September 2009 WACC, logically then other forecasts such as the LCI and PPI should also use 2009 forecasts as a result of the inter-relationship between these inflators and the CPI.

This is a difficult issue because the Commission's task is to calculate the starting price adjustment that it would have calculated in September 2009—but it now has the complication of making a reset decision in late-2012 and has actual data to update earlier forecasts. The Commission has rightly decided to continue to use the 2009 WACC estimate and thus use the related 2009 CPI to maintain consistency with the WACC. We suggest that to maintain consistency between the CPI, PPI and LCI in this decision that the Commission revert to forecasts available at September 2009, rather than attempting to mix and match historical and up to date forecasts that are inherently linked and correlated.

The PPI may not be the best index to use for suppliers costs

Our second concern about the use of inflators is whether an all-industries PPI is the best way to inflate the materials and services portion of suppliers' operating costs. In Table 4.3 below we look at the movements in the PPI in recent quarters and the analysis completed by Statistics NZ of the key drivers behind those movements. Most of the changes seem to be driven by factors such as increases in energy prices and changes in prices of agricultural raw materials. In our view, such factors are unlikely to match the changes in the costs of specialised services and material and equipment for an electricity distribution network.

Table 4.3: Factors Driving Recent Changes in the Producer Price Index (PPI)

PPI Quarter	Key Drivers for Input Indexes (prices paid by producers)	Key Drivers* for Output Indexes (prices received by producers)
June 2012	Overall 0.6% rise ▪ **Electricity and gas supply rise (8.2%)** ▪ Petroleum & coal manufacturing rise ▪ Dairy product manufacturing fall	Overall 0.3% rise (on previous quarter) ▪ **Electricity and gas supply prices increased (10.7%)** ▪ Property operators and real estate rise ▪ Dairy cattle farming fall
March 2012	Overall 0.3% rise ▪ **Electricity generator prices increase** ▪ Food manufacturers fall	Overall 0.1% fall ▪ **Manufacturing decreased** ▪ Sheep, beef and dairy decreased ▪ Electricity and gas supply prices increased (6.9%)

[9] The economics literature on the linkages between PPI and CPI is well-developed. See for example Ackay, S "The Causal Relationship between Producer Price Index and Consumer Price Index: Empirical Evidence from Selected European Countries" International Journal of Economics and Finance Vol. 3, No. 6; November 2011. Available online at: www.ccsenet.org/journal/index.php/ijef/article/download/12703/8905

PPI Quarter	Key Drivers for Input Indexes (prices paid by producers)	Key Drivers* for Output Indexes (prices received by producers)
December 2011	Overall rose 0.5% ▪ Farm-gate milk prices rose ▪ Prices paid for electricity generation fell	Overall 0.1% rise ▪ Agriculture (milk and meat prices) rose ▪ Horticulture & fruit prices fell ▪ Mining prices rose
September 2011	Overall 0.6% rise ▪ **Electricity generator prices increased (sector index up 19.3%)** ▪ Dairy product manufacturing fell from lower farm gate milk prices	Overall 0.2% rise ▪ **Electricity and gas supply prices rose (sector index up 12.8%)** ▪ Farm-gate milk prices fell ▪ Dairy product manufacturing fell

Note: * The largest driver for each quarter is shown in **bold**

Source: http://www.stats.govt.nz/browse_for_stats/economic_indicators/prices_indexes/producers-price-index-info-releases.aspx

One way to better reflect the price changes facing suppliers would be to create a tailored price index as has been done in other sectors. Such an index would be derived from the "building blocks" of various indices published by Statistics NZ.

A similar approach has been carried out in other sectors of the economy. For example, the Local Government Cost Index (LGCI) has been created to forecast medium term changes in prices for local authorities to use in their budgeting processes. The LGCI is based on nine adjustors covering the costs (opex and capex) faced by local authorities – one of which is energy. The figures used to create these adjustors are from the Statistics NZ price indices—the energy adjustor uses the "PPI outputs – electricity generation and supply" and "Total salary and wage rates – private sector".

5 Cash Flow Timing Assumptions

The Commission has changed its approach to cash flow timing by aligning the recognition of most expenditure and revenue items to mid-year. This is a substantial improvement over the assumptions used in the 2011 DPP draft price reset decision.

While these changes remove many of the inconsistencies in the old "mixed period" discounting approach, the changes also introduce some new inconsistencies:

- **Depreciation on assets commissioned.** New assets are timed to enter the RAB at mid-year, but depreciation on those assets does not start to run until year-end
- **Regulatory tax allowance.** The tax payable component of the regulatory tax allowance is assumed to occur at year-end, but tax is paid throughout the year; and
- **The return on assets.** Returns are assumed to occur at year-end, when interest on debt and dividends to shareholders are paid throughout the year.

As a general point, while the Commission has attempted to improve the accuracy of its timing assumptions, this accuracy comes at the expense of simplicity. Many regulators—including the AER and IPART—do not make explicit timing assumptions for each component of the building blocks, but chose the simple approach of assuming all occur at either year-end or mid-year. Provided this approach recognises the working capital required, it is simple, transparent and easily modelled.

The Commission's approach—while arguably more accurate—struggles to achieve internal consistency. The modelling philosophy appears to lie somewhere between the two extremes of a detailed investment model and a simple regulatory model. Elements of the approach are more aligned to the more detailed investment analysis, project evaluation and valuation models used by financial analysts. In these models, cash flow timing assumptions are important. However, as summarised above, not all items have accurate timing assumptions.

It is not clear that the increase in accuracy achieved by the Commission outweighs the cost of added complexity. In the DPP model, for example, many of the building block components have at least two values for any year—the "as calculated" value and the "timing assumption" value. Both of these values are used in the model at various times and for different purposes. While the time shifting appears mathematically correct, it is confusing and non-transparent.

Putting to one side the debate over the level of model and timing assumption accuracy that is appropriate, we see two further improvements that could be made:

- Ensuring that the working capital provided through cash flow timing assumptions is made explicit and acknowledged as a legitimate cost
- Aligning the timing of depreciation with the date when assets are commissioned. Although this alignment does not create any advantage to suppliers (because the change would not have any NPV impact), this treatment would improve the consistency of the approach. All else being equal, we would expect suppliers to prefer depreciation to return on capital.

These points are also raised in our report on proposed changes to the timing assumptions for the CPP Input Methodologies.

5.1 Providing an Explicit Allowance for Working Capital

The Commission has implicitly provided an allowance for working capital through the 20-day lag assumed for the timing of revenue (relative to expenditure). In our view, this is likely to provide a reasonable estimate of working capital costs because the difference between debtor days and creditor days is likely to be in the order of 20 days. However, we encourage the Commission to acknowledge that the difference in timing recognition is designed to allow regulated businesses to recover working capital.

In our experience in other regulatory regimes, an allowance for the costs of financing working capital takes into account:

- Debtor days—the average length of time between revenue recognition (invoices sent out) and the receipt of cash
- Creditor days—the average length of time between recognition of expenditure (invoices received) and the payment of cash
- The quantum of debtors
- The quantum of creditors usually for operating expenditure, capital expenditure (excluding major projects where working capital is included as interest during construction) and inventories.

A typical formula used by regulators in Australia (such as IPART, the Essential Services Commission of South Australia and the Queensland Competition Authority) to calculate working capital is[10]:

*Working capital = ((Annual accounts receivable * average debtor days/365)-(Annual accounts payable * average creditor days/365)) * WACC*

While the Commission's 20-day revenue lag assumption produces similar results to the standard working capital allowance formula, we suggest that an explicit allowance would help to improve transparency and predictability. The Commission currently does not acknowledge that the 20-day revenue lag is in fact an allowance for working capital.

5.2 Applying Depreciation from the Date of Asset Commissioning

In the draft reset decision, the Commission has retained year-end timing assumptions for both return of capital (depreciation) and return on capital. At the same time it has moved capital expenditure timing to mid-year. This creates an anomaly between capital expenditure commissioning and when depreciation starts to be calculated on commissioned assets.

Because capital expenditure is recognised from the date of asset commissioning—which is assumed to be mid-year in the DPP—regulated suppliers should receive depreciation on assets and return on capital from that date. However, the current year-end timing assumption for depreciation in the DPP financial model does not achieve this outcome. The financial model shows that assets commissioned in one year (e.g. in the middle of 2012/2013) receive no depreciation until the end of the following year (2013/2014). This means that the depreciation allowance, and therefore the allowed revenue, is understated.

[10] For a summary of approaches to working capital in Australia see Deloitte "Queensland Competition Authority: SunWater Working Capital Allowance" http://www.qca.org.au/files/W-Deloitte-Report-WorkingCapitalAllowance-0911.pdf. For an example of an explicit allowance for working capital in a regulatory decision see ESCOSA 2005-2010 Electricity Distribution Price Determination at pages 122-124, http://www.escosa.sa.gov.au/library/050405-EDPD_Part_A_StatementofReasons_Final.pdf.

Providing depreciation from the date of asset commissioning will not change overall financial outcomes for suppliers, because depreciation reduces the regulatory asset base and therefore lowers return on capital. However, depreciation returns capital to the supplier within the current regulatory period, and is therefore preferable to suppliers. The argument that the Commission's inconsistent treatment is NPV neutral also misses the point. It would equally be NPV neutral for the Commission to allow EDBs no revenue over a regulatory period by capitalising the foregone revenue into the closing RAB. Such an outcome is clearly not desirable.

Regulators overseas have recognised this issue, and adopt a mid-year assumption for capital expenditure with consistent timing for depreciation. For example, the Independent Pricing and Regulatory Tribunal of New South Wales (IPART) depreciates commissioned assets at half the normal rate in the year of commissioning[11].

The purpose of the regulatory building blocks model is to allow regulated businesses to recover their efficient operating costs incurred within a period within that period. Depreciation on commissioned assets is clearly a legitimate and efficient cost incurred within a period, and should be able to be recovered within that period.

11 See "Comparison of financial models—IPART and the Australian Energy Regulator", July 2012, Section 3.2.2

6 Analysis of Additional Allowances

The Commission has completed an analysis (in Appendix J of the draft reset decision) to evaluate whether suppliers should receive additional allowances to reflect the relatively large margin of error resulting from the Commission's forecasts under the DPP.

An additional allowance better reflects the Part 4 objectives

We have previously supported an approach that provides a "margin of tolerance" above industry WACC or uses a rate of return band when adjusting starting prices in a reset decision.[12] This would allow downward P_0 adjustments to be at the top of a range, recognising the inherent margin for error in simple, low cost DPP estimation approaches.

We believe that additional allowances clearly better achieve the objectives of Part 4 for the DPP because they:

- Reflect that forecasting errors might have negative consequences for investment and innovation (section 52A(1)(a)); while
- Still ensure that suppliers are limited in their ability to extract excessive profits (section 52A(1)(d)).

This last point is particularly important. The draft reset decision continues to equate an unlimited ability to extract excessive profits with forecast returns above the Commission's estimate of industry WACC. In reality, there is a range of profits that can be earned by a supplier before those returns can be properly described as "excessive". There are also reasons that suppliers will earn returns above the industry WACC that have positive economic effects. For example, if higher returns come through innovation or cost savings—functional rents—then the benefits will ultimately be passed to consumers. In these circumstances, higher initial returns are welfare enhancing because they give suppliers the incentive to pursue innovations and cost savings.

Commission assumptions regarding additional allowances

The Commission assumes that additional allowances would have two impacts:

- Reduce the likelihood that suppliers will seek CPPs (avoiding the costs of that process); and
- Increase the prices paid by consumers.

In the Commission's analysis, the second impact outweighs the first—meaning that additional allowances would make customers worse off. This conclusion is reached on the basis that the additional allowances will only cause a marginal decrease in a supplier's propensity to seek a CPP if the supplier does not feel that it will be able to earn adequate returns under the DPP. This conclusion is based on very restrictive assumptions that limit the usefulness of the analysis in Appendix J of the draft reset decision. Suppliers are expected to make their decision on whether to seek a CPP based on administrative costs alone. Suppliers are also assumed to only have two available courses of action—doing nothing (i.e. remaining on the DPP) or seeking a CPP.

CPPs involve costs that are not simply administrative

The analysis in Appendix J of the draft reset decision assumes that the cost to suppliers of a CPP process is relatively modest—being limited to the administrative costs of

[12] See Castalia report to Vector, "Evidence on the Impacts of Regulatory Incentives to Improve Efficiency and Service Quality" Vector letter to Commerce Commission attachment A, EDB DPP 5 July 2012

preparing the CPP. In fact, a CPP application involves a significant element of risk for suppliers.

In fact, the CPP process is essentially a *de novo* price reset, and could result in worse outcomes for the supplier. These additional risks to the CPP process will clearly be factored into a supplier's decision to make an application.

Suppliers have several options when faced with an incorrect DPP

The analysis also assumes that the cost to customers is only limited to the quantum of the additional allowances. However, a DPP that does not allow a supplier to earn reasonable returns will potentially have broader impacts than just the cost of preparing a CPP. A supplier in this situation has essentially four alternative responses to an inappropriate DPP decision by the Commission:

- **Do nothing**—that is, pay shareholders less than reasonable returns. At the very least this will negatively affect investor confidence for the business, for the sector, and possibly even for the wider regulated economy. In essence, investors will be concerned by what they see as a failure of the regulatory framework. The costs—while not directly observable or measurable—could be significant.
- **Apply for a CPP**. Under this option the supplier will bear the cost of preparing for the CPP.
- **Appeal the DPP decision**. While there is no merits review available for the DPP reset process, suppliers still have the option of judicial review. An application for judicial review should be a low probability event if the Commission makes prudent and well-justified decisions, but remains an option for suppliers facing an unfavourable outcome under the DPP; or
- **Reduce service quality**. The quality standards under a DPP relate solely and narrowly to reliability measures. This means that a supplier could restrain expenditure in areas that will have a low impact on reliability, such as customer support and responsiveness. These actions could have a material negative on customers that has not been factored into the Commission's simple analysis in Appendix J of the draft reset decision.

While there may be debate about the probability of each of these options, it is plausible that rather than applying for a CPP with exposure to the risk of worse outcomes, a prudent supplier will implement a combination of the first and last options. That is, the supplier will find a reasonable trade-off between shareholder expectations and service standards. Any reduction in service standards—particularly arising from under investment—is likely to have negative impacts on customers. The risk for the Commission if it ignores these impacts is that it may take several years before any impacts emerge, and many more years of higher investment to correct.

For this reason—as well as the inherent margin for error in the DPP methodology due to the use of non-supplier specific data—we believe the use of either a WACC range or an additional allowance is justified and consistent with the intent of the Part 4 objectives. The inherent margin of error in the DPP methodology is compounded by the various inconsistencies in the methodologies identified in this report, such as the approach to econometric modelling and forecasting, the use of less reliable data, and inconsistencies in timing assumptions. Failing to address these modelling issues will lead to the Commission overstating the current and projected profitability of suppliers.

7 Process Issues for 2015 DPP Reset

Most of this report focuses on substantive ways to improve the Commission's assessment of the current and projected profitability of suppliers. However, the process of engaging with regulated suppliers and other stakeholders during price reset also matters. We appreciate that the Commission has been under unique time pressure during this mid-period reset—due to statutory deadlines and changing judicial interpretations on specifying starting price adjustments as input methodologies.

In this context, some of the processes followed by the Commission for the mid-period reset have been helpful. The Commission's Q&A session on the financial and econometric models provided a valuable opportunity to interact with Commission staff on some of the technical details of the draft reset decision. The publication of supporting material on the Commission's website is also very important to enable fully informed submissions on the decision.

We have three specific suggestions that we believe would build confidence in the results of the next DPP reset in 2015:

- **Verifying supplier data before releasing the draft reset decision.** As noted above, the timeframes for deciding on this mid-period reset have been unique. However, in several areas, the Commission has not been able to finalise data inputs prior to making the decision. In our view, the Commission should have engaged in a more constructive and frequent dialogue with suppliers before the decision was reached. This would have ensured that a complete set of data was available, and would have helped to understand the reasons that certain suppliers appear to be "outliers" in the Commission's dataset.
- **Carrying out pre-consultation on the approaches to forecasting.** This report raises concerns about several areas where the Commission's approach to forecasting has changed substantially from the superseded 2011 draft reset decision—the use of econometrics to forecast opex and constant price revenue growth, the assumptions used to model cash flow timing, and the use of inflation indices set at different times. The approaches proposed for forecasting should be discussed in advance with suppliers (together with alternative approaches), to help build confidence in the ability of the proposed forecasts to accurately reflect efficient supplier costs and incentives.
- **Carrying out pre-consultation on the financial model.** We have previously highlighted that it is good regulatory practice to release the financial model that will be used to reset prices before reaching a draft reset decision. The Australian Energy Regulator (AER), the Australian Competition and Consumer Commission (ACCC), and Ofgem and Ofwat in the United Kingdom all consult separately on financial models before releasing a price determination. This pre-consultation process helps to resolve issues that are more difficult to address in the context of decisions on prices or revenues.

These processes have been followed by regulators throughout the world. For example, the AER applied a pre-consultation process in its first price determinations for Australian electricity distributors. In late 2007, the AER released an issues paper on the schemes and models that it was required to develop and invited written submission from stakeholders[13]. In early 2008, the AER released the proposed schemes and models, held public forums to receive comments from stakeholders, and invited written submissions[14]. In June 2008, the AER published its final decisions on the schemes and models, with reasons and analysis of stakeholder comments[15].

Although verifying supplier data and consulting on technical forecasting details will not result in a complete consensus on the best ways to reset prices, it will build confidence in the Commission's modelling and will help to focus concerns on key areas before a draft reset decision is made. We understand that the Commission intends to engage with suppliers in the time between this mid-period reset and the 2015 reset to discuss forecasting approaches. We encourage this interaction, and recommend that the Commission also formally releases a statement of proposed approach and financial models before it releases a draft reset decision for the 2015 reset.

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13 "Guidelines, models and schemes for electricity distribution network service providers", AER, November 2007 and submissions at http://www.aer.gov.au/content/index.phtml/itemId/717527

14 "Proposed PTRM explanatory statement", AER, April 2008 and submissions at http://www.aer.gov.au/content/index.phtml/itemId/728425.

15 "Final decision: Electricity distribution network service providers: Post tax revenue model", June 2008.

Appendix A Stata Code for Castalia Econometric Models

```
* Network opex – Castalia's Preferred Model in Table 2.1*
foreach scale in "lcircuit_length_total icp_km"{
	reg ldirect  `scale', robust
	ovtest
}

* Total controllable opex – Castalia's Preferred Model in Table 2.2 *
foreach scale in "lcircuit_length_total icp_km"{
	reg lopex `scale' if year >2008, robust
	ovtest
}

* Total controllable opex – Castalia's Alternative Model in Table 2.2 *
foreach scale in "lcircuit_length_total lelectricity_supplied icp_km"{
	reg lopex `scale' if year >2008, robust
	ovtest
}
```

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