BOARD STAFF RESPONSE TO
ENBRIDGE GAS DISTRIBUTION INC. #3

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: ExhL/T1/S2

I.A1.Staff.EGDI.3

Preamble:
On page 2 of its report and in subsequent pages, PEG discusses the building block model, and on page 17 PEG states that there have been changes in the overarching framework used to implement building block regulation, particularly in the UK which, according to PEG, has more experience with this IR method than Australia.

Request:

a. Please provide a list of all cases (docket number, date) where PEG has provided advice or submitted testimony in Australia regarding the application of building block regulation model to electricity and/or natural gas distributors.

b. Please identify the lead witness or advisor.

c. Please also provide copies of reports and/or written testimony in the above matters.

RESPONSE

a. Formal testimony is rare in Australian regulation, and typically only takes place in court or panel appeals of regulatory decisions. PEG has provided formal testimony in five such appeals of regulatory decisions; all five involved application of the building block regulation model to electricity or gas distributors. None of the cases have docket numbers *per se*, but the technical details and dates of each case are presented below:

    - Before the Supreme Court of Victoria, Australia, No. 7669 of 2000; evidence on behalf of TXU Australia, 2000.

    - Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2005.

- Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2006.

- Before the Appeal Panel, South Australia, Australia; evidence on behalf of the Essential Services Commission of South Australia, 2006.

- Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2008.

PEG has also submitted many expert reports in Australia that either addressed the merits of building block approaches to regulation, or were used in building block reviews of electricity or gas distribution rates. The list below provides a synopsis of PEG's main reports related to building block regulation, organized by topic. PEG has also written many other reports in Australia where the issue of building block regulation arises but it is not central to the report.

I. The Merits of "TFP-Based Regulation" and Building Block Regulation/The Experience with Incentive Regulation in the US and the UK
   a. *Updating Price Controls for Victoria's Power Distributors: Analysis and Options*, September 1997 Report for Victoria's electricity distribution industry

   b. *Review of Distribution Price Controls in Victoria: Comments of NERA's Proposed Approach and the Regulator-General's Consultation Paper*, September 1998 Report for Victoria's electricity distribution industry

   c. *Incentive Regulation and External Performance Measures: Operationalising TFP – Practical Implementation Issues*, June 2001 Report to the Utilities' Regulatory Forum, on behalf of Citipower

II. Victoria Electricity Distribution Price Review in 2004-05; PEG advised the Essential Services Commission (ESC) on a number of different issues that arose during the building block review of electricity distribution rates; the most important reports on these issues were:

a. *Evaluation of KPMG Report: Trends in Labour Rates and CPI-X Regulation, November 2004*

b. *Evaluation of Monash University Report: An Econometric Analysis Determining the Evidence of Differences Between Rural and Urban Betas for Electricity Distributors, January 2005*

c. *Response to Further Rural Risk Premium Submissions, May 2005*

d. *Comments on Wilson Cook Operating Expenditures Benchmarking Study, October 2005*

III. *Incentive Power and Regulatory Options in Victoria*, May 2005 Report for the Essential Services Commission (ESC) in Victoria; this report undertook a number of detailed mathematical simulations of the outcomes of alternative applications of building block and TFP-based regulatory models. PEG's models simulated how utilities would respond to different incentive regulation options. This report also estimated customer and shareholder benefits under each of the building block and TFP-based regulatory scenarios.

IV. Victoria Gas Distribution Price Review in 2007-08; PEG advised the ESC on a number of different issues that arose during the ESC's building block review of gas distribution rates, the most important reports on these issues were:

a. *Response to Meyrick and Associates Benchmarking Reports*, July 2007

b. *Opex Rate of Change and Productivity: Response to Meyrick and Associates Reports, July 2007*

c. *Response to Worley Parsons Benchmarking Report, July 2007*

d. *Cost Escalation for Distribution Capital Expenditure: Assessment, July 2007*

e. *Further Response to Meyrick and Worley and Parsons Benchmarking Reports, January 2008*

f. *Opex Rate of Change and Productivity: Response to Consultant Reports, February 2008*

g. *Cost Escalation for Distribution Capital Expenditures: Updated Recommendations, February 2008*

h. *Using the Rate of Change Formula to Update Allowed Opex in Gas Connection Charges, November 2008*

V. AEMC Review into the Use of Total Factor Productivity for the Determination of Prices and Revenues

London Economics International (LEI) discussed this proceeding in its report on building block regulation. It wrote that

"the Australian Energy Market Commission (AEMC) has reviewed whether or not to apply a TFP-based method for escalating rates (via an "I-X" formula) or to retain the building blocks approach…the AEMC concluded that it is better to retain the building blocks approach" (Exhibit A2, Tab 10, Schedule 1, Page 13).

LEI's representation of this review is not accurate. Australia's National Electricity Rule 6.4.3(a) states that "the annual revenue requirement for a distribution network service provider for each regulatory year of a regulatory control period *must be determined using a building block approach*…." (emphasis added). The building block model was therefore mandated by law at the time the Australian Energy Regulator (AER) was established. The AER therefore had no choice but to 'retain' the building blocks approach in every regulatory review it has conducted.

In June 2008, the Victoria Department of Primary Industries (DPI) proposed a "rule change" application that would allow greater flexibility in

Australia's energy regulatory framework. In particular, the DPI asked the AEMC to add a "TFP-based option" to the framework used to regulate gas and electricity network prices. The AEMC's review of this rule change application was, in fact, the review that was referenced in the LEI report.

However, the issue before the AEMC was *not* whether a TFP-based approach would replace the mandated building blocks approach; it was only whether the AEMC should add a TFP-based regulatory option to Australia's regulatory framework. Doing so would give AER the option of using something other than building blocks for price reviews.

In June 2011, the AEMC issued its final report on the rule change application, and it chose to add a TFP-based option to Australia's energy regulatory framework. In reaching this conclusion, the AEMC wrote (page i) that "we found the use of TFP methodology in setting the allowed revenue path has the potential to create stronger incentives to pursue cost efficiencies compared to the building block approach…furthermore, a TFP methodology could reduce the scope for the service provider to boost returns by exploiting its information advantage over the regulator, and has lower regulatory costs." These statements run counter to LEI's assertion that "the AEMC concluded that it is better to retain the building blocks approach."

PEG was extensively involved in this rule change review. In particular:

- PEG provided advice to parties involved in the submission of the Victoria DPI's rule change application

- PEG prepared seven different reports, and one set of empirical analyses, that were submitted to the AEMC during the review of the rule change application
    - A March 2009 submission in response to the AEMC's *Framework and Issues* report
    - A May 2009 supplemental response to the *Framework and Issues* report
    - A May 2009 spreadsheet-based analysis of the incentive impacts and 'incentive power' of building blocks and TFP-based regulatory approaches

- An October 2009 submission on the AEMC's *Discussion Paper*
- An April 2010 submission on the AEMC's *Preliminary Findings* report
- An August 2010 submission on the spreadsheet modeling of other consultants
- A September 2010 submission on the draft report
- A supplemental February 2011 submission on the draft report

b. For every piece of testimony or expert report identified in part a), the lead witness or advisor was Dr. Larry Kaufmann.

c. Copies of the five formal testimonies PEG has submitted in building block regulatory proceedings are provided. PEG's view is that it would be unduly burdensome to provide copies of the 24 other reports referenced in part a) that PEG has written on these issues, as well as the reports that Dr. Kaufmann and PEG have provided on related issues in Australia.

Pacific Economics Group
Economic and Litigation Consulting

Principles and Evidence for Price-Based CPI-X Regulation:

An Evaluation of the Electricity Distribution Price Determination 2001-2005

Pacific Economics Group
Economic and Litigation Consulting

Principles and Evidence for Price-Based CPI-X Regulation:

An Evaluation of the Electricity Distribution Price Determination 2001-2005

December 2000

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EXECUTIVE SUMMARY

This report addresses whether the Electricity Distribution Price Determination 2001-2005, issued by the Office of the Regulator-General (ORG), complied with the Victorian Electricity Supply Industry Tariff Order (the "Tariff Order"). Clause 5.10 in the Tariff Order imposes restrictions on the review of price control arrangements by the ORG. The first restriction listed in this clause is that the ORG must "utilize price based regulation adopting a CPI-X approach and not rate of return regulation."

In my opinion, the Determination did not comply with this mandate. While the Determination does implement a form of "CPI-X" regulation, it is not the "price based CPI-X regulation" that is required by the Tariff Order. The difference is crucial. Throughout the world, CPI-X regulation has been applied in two fundamentally different ways. One can be termed "price based," since allowed rates are based on industry performance measures rather than a company's own costs. This approach simulates the operation of competitive markets, where the costs of any single firm do not affect the market price. Alternatively, CPI-X regulation can be "cost based." This approach computes revenue requirements using traditional cost of service methods, but allows projected revenues to be recovered over a multi-year period using a "CPI-X" formula. This application essentially fits traditional rate of return regulation into a CPI-X framework, and as such tends to blur the difference between rate of return and CPI-X regulation.

Only the former price-based CPI-X application is consistent with the Tariff Order. Clause 5.10 of the Order draws a clear distinction between what is mandatory (price-based CPI-X regulation) and what is prohibited (rate of return regulation). Any ratemaking approach that blurs this distinction cannot be in compliance with the law. Thus while the Price Determination is consistent with "CPI-X" regulation as it has been practiced in some jurisdictions, it does not comply with the Tariff Order mandate to employ a regulatory approach that clearly differs from rate of regulation.

The ORG and its advisors argue that its Determination contains features that are consistent with CPI-X regulation but not with rate of return regulation. In evidence presented before an Appeal Panel, Dr. Jeff Makholm of National Economic Research Associates ("NERA") claims that three particular features create a "fork in the road" between rate of return and CPI-X regulation. Either individually or as a group, he states that these factors are never associated with rate of return regulation but are part of CPI-X ratemaking. These factors are:

- CPI- X regulation sets definite, pre-established periods between examinations of utility cost; there is no fixed period between rate cases under rate of return regulation.
- In CPI-X based regulation, prices adjust between scheduled rate cases according to a formula; prices are fixed under rate of return regulation and are adjusted only at the time of a new rate case.
- Utilities are permitted to adjust the structure of their tariffs under CPI-X regulation; such adjustments are not permitted under rate of return regulation.

While there is some truth to these assertions, there is also contradictory evidence. Consider the following examples, all of which have been implemented under cost of service ratemaking.

- Rate of return regulation can feature fixed, pre-established periods between general rate cases (GRCs). For example, prior to the implementation of performance-based regulation (PBR) in California, there was a regular, three-year cycle between GRCs. Fixed periods between rate cases are also often part of merger agreements. Commissions routinely approve multi-year rate freezes for the merged companies. Some US States have also imposed multi-year rate freezes by legislation.
- Prices can be adjusted between rate cases. For energy utilities, fuel costs are typically adjusted automatically and more frequently than "base rates." Base rates themselves can be adjusted between formal rate reviews. One example is California's so-called attrition rate adjustments, which used indexing mechanisms to adjust allowed cost recovery between the scheduled GRCs.

- Tariff flexibility is sometimes allowed under rate of return regulation. The most common example is rate discounting to price-sensitive customers. Several US states have allowed such rate discounting under cost of service regulation. Utilities are sometimes permitted to recover revenues lost from discounting from other customers. This clearly adjusts the structure of tariffs even as overall revenue requirements remain fixed.

In light of this evidence, it cannot be claimed that the three features listed by Dr. Makholm constitute a "fork in the road" that can be used to distinguish rate of return from CPI-X regulation.

One factor that is critical for implementing price-based CPI-X regulation is the use of "external" performance standards. External performance standards are based on measures outside of the control of the subject utility. Examples include *industry* trends in total factor productivity (TFP) and benchmark cost comparisons. While external standards alone are not sufficient for identifying price-based CPI-X regulation, they are *necessary* for this regulatory approach. North American regulators have identified the use of external performance standards as the key distinguishing feature between cost of service regulation and performance-based regulation. Some regulators have explicitly rejected the factors cited by Dr. Makholm. Since the ORG's Determination fails to use external performance standards in ratemaking, it does not comply with the Tariff Order mandate to use price-based CPI-X regulation.

Dr. Makholm is also incorrect when he asserts that CPI-X regulation *always* reviews company costs when indexing plans are reviewed. Numerous CPI-X regulation plans for North American telecommunications utilities have not updated indexing formulas using the costs of the regulated company. Four prominent examples are for US West-North Dakota, NYNEX-Rhode Island, NYNEX-Maine and the local exchange carriers subject to the jurisdiction of the Federal Communications Commission (FCC). None of these plans used the company's own costs when updating the indexing formulas that adjust allowed rates. These plans are therefore examples of pure "price-based" CPI-X regulation as mandated by the Tariff Order.

While the lack of data in Victoria does create challenges for regulators, in my opinion it is feasible to implement price-based, CPI-X regulation in Victoria. One possible approach is a "rolling X-factor," where the X-factor is based on industry TFP trends for all five distributors in the State and is updated at regular intervals as new TFP data become available. A second option is to utilize data from overseas until sufficient data are available in Victoria to estimate long-run TFP trends in the state.

I. INTRODUCTION

In September 2000, the Office of the Regulator General (ORG) issued its Price Determination for the distribution businesses (DBs) in Victoria. This Determination included price cuts in 2001 and an X-factor of 1% in each of the following four years. TXU has appealed this Determination, claiming that the ORG employed rate of return methods rather price-based CPI-X regulation. This would be contrary to Victorian law, for Clause 5.10 of the Tariff Order requires price reviews to utilize price-based CPI-X regulation and not rate of return regulation.

TXU has asked me to evaluate whether the ORG's Determination was consistent with Clause 5.10 of the Tariff Order. After carefully reviewing the evidence, I believe that the ORG has not complied with this Tariff Order mandate. The reasons for my opinion are as follows:

- The Determination employs a form of "CPI-X" regulation but not the "price-based CPI-X regulation" that is required by the Tariff Order. The difference is crucial. Throughout the world, CPI-X regulation has been applied in two fundamentally different ways. One can be termed "price based," since allowed rates are based on industry performance measures rather than a company's own costs. This approach simulates the operation of competitive markets, where the costs of any single firm do not affect the market price. Alternatively, CPI-X regulation can be "cost based." This approach computes revenue requirements using traditional cost of service methods, but allows projected revenues to be recovered over a multi-year period using a "CPI-X" formula. This application essentially fits traditional rate of return regulation into a CPI-X framework, and as such tends to blur the difference between rate of return and CPI-X regulation.

  In my opinion, only the former type of CPI-X application is consistent with the Tariff Order. Clause 5.10 of the Order draws a clear distinction between what is mandatory (price-based CPI-X regulation) and what is prohibited (rate of return regulation). Any ratemaking approach that blurs this distinction cannot be in compliance with the law. Thus while the Price Determination is consistent with "CPI-X" regulation as it has been practiced in some jurisdictions, it does not comply with the Tariff Order mandate to employ a regulatory approach that clearly differs from rate of regulation.

- The ORG's criteria for differentiating between price-based CPI-X regulation and rate of return regulation are not always satisfied in practice. In evidence presented to an Appeal Panel, Dr. Jeff Makholm of National Economic Research Associates (NERA) claims that three particular features create a "fork in the road" between rate of return and CPI-X regulation. Either individually or as a group, he states that these factors are *never* associated with rate of return regulation but are part of CPI-X ratemaking. However, all three features have in fact been part of explicit cost of service regimes. These factors therefore cannot be used to distinguish rate of return from price-based CPI-X regulation.

- Theory and practice suggest that "external" performance standards are necessary for implementing price-based CPI-X regulation. External performance standards are based on measures outside of the control of the subject utility, such as *industry* trends in total factor productivity (TFP) and benchmark cost comparisons. Since the Determination does not use external performance standards for ratemaking, it is not consistent with the mandate to implement price-based CPI-X regulation.

- Dr. Makholm incorrectly asserts that CPI-X regulation *always* examines company costs when indexing plans are reviewed. Numerous CPI-X regulation plans for North American telecommunications utilities have not updated indexing formulas using the costs of the regulated company. These plans are examples of pure "price-based" CPI-X regulation as mandated by the Tariff Order.

- While the lack of data in Victoria does create challenges for regulators, it is feasible to implement price-based, CPI-X regulation in Victoria.

The remainder of this report will elaborate on each of these points.

Pacific Economics Group
Economic and Litigation Consulting

II. CLAUSE 5.10 OF THE TARIFF ORDER

Areas of Dispute

The ultimate issue is whether the Determination complied with Clause 5.10 of the Tariff Order, entitled "Restrictions on review of price control arrangements by the Regulator-General." Before going to the details of the arguments, it is valuable to review the mandates and prohibitions stemming from this Clause. Three specific paragraphs of Clause 5.10 have been the subject of dispute.

The most directly relevant of these is paragraph (a), which states that "(i)n making any price determination…the Regulator General must…utilize price based regulation adopting a CPI-X approach and not rate of return regulation." As explained in detail in the following section, the ORG and its advisors have argued that they complied with this requirement since there is a "fork in the road" between these regulatory alternatives that depends on three factors: whether there is a fixed period between rate cases; whether prices adjust between rate cases; and whether the structure of tariffs can be adjusted. They state that *only* CPI-X regulation has fixed periods between rate cases, adjusts prices between reviews, and allows for flexibility in the tariff structure. These features *never* exist under rate of return regulation. The ORG argues that since it has taken the fork in the road and adopted a regulatory approach that incorporates the three relevant features, it has complied with paragraph (a) of Clause 5.10.

It is also important to note that the ORG and its advisors believe that rate of return and CPI-X regulation share certain features. The most important of these is that rates are tied directly to the company's own costs when rates are reviewed.[1]

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[1] Under rate of return regulation, this purportedly occurs whenever there is a rate case. Under CPI-X regulation, rates are re-setting to company costs at the expiration of the indexing period. For example, in the *Transcript Proceedings*, Dr. Jeff Makholm of National Economic Research Associates (NERA) testified that "under all

Accordingly, CPI-X regulation is properly viewed as "an extension and a modification and an enhancement of rate of return regulation in certain areas" rather than an entirely different regulatory system.[2]

Some parties have also questioned the consistency of paragraphs (a) and (b) of this Clause under certain applications of CPI-X regulation. Paragraph (b) says that "where the value of the fixed assets which were allocated to a Distributor…is required to be taken account (in a price determination), use the adjusted asset value for that Distributor as at 1 July 1994 determined in accordance with the table set out below, adjusted to take into account inflation and depreciation on the asset value.." A table is then presented for each of the five DBs that includes figures for the optimized depreciated replacement cost (ODRC), an adjustment, and the adjusted asset value (opening book value). Dr. Makholm of NERA has stated that paragraphs (a) and (b) are internally inconsistent unless the review of each DB's price controls depends directly on its own capital returns.[3]

It has also been argued that paragraphs (a) and (e) of the Order are essentially redundant. Paragraph (e) says that the price controls will be in effect for a period of not less than five years. As discussed further in the following section, the ORG and its advisors argue that a fixed, multi-year period between rate reviews is inherently a feature of CPI-X regulation but is never part of rate of return regulation. Under this interpretation, the paragraph (a) requirement to use CPI-X regulation necessarily subsumes the paragraph (e) requirement of a multi-year period between rate reviews.

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price cap plans which I have experienced anywhere in the world, if a company performs well and generates very good earnings…then when the time comes around to review the plan (it) is facing a price cut because its average costs are simply going to be lower than they started out to be. And that's a common feature – it's not a common feature, it's a universal feature of price cap plans, which is that at the end of the formula period you do a basic re-examination of costs..."; page 347 lines 26-31-p. 348 lines 1-6.

[2] *Op cit, p. 341, lines 22-24.*

[3] *See the Transcript of Proceedings, Appeal Panel Electricity Distribution Price Determination 2001-2005, p. 355, lines 15-22.*

Evaluation

In my opinion, each of these assertions regarding Clause 5.10 of the Tariff Order is incorrect. I examine the specific claims regarding paragraph (a) in much greater detail in the following section. In general, however, I believe that the ORG's conception of CPI-X regulation violates both the spirit and language of paragraph (a) of Clause 5.10.

This paragraph clearly has two aims: it mandates a particular form of regulation (price-based CPI-X regulation) and it prohibits another form (rate of return regulation). The Tariff Order would not include the latter prohibition if CPI-X regulation was viewed as an enhancement of a fundamentally cost of service/rate of return regulatory framework. If this were the case, paragraph (a) could have stopped at the word "approach." There might then be an argument for integrating rate of return ratemaking into a CPI-X indexing formula. Instead, paragraph (a) draws a sharp line between these alternatives. Accordingly, it cannot be concluded that a Price Determination that blends CPI-X and rate of return regulation, or that views the former merely as an "enhancement" of the latter, is able to comply with what it is both mandated and prohibited by paragraph (a).

It is also noteworthy that the ORG's advisors acknowledge that the Price Determination mixes rate of return and CPI-X regulation. In oral testimony at the Appeal Panel, Dr. Makholm states that when the 2001 price decrease is considered in isolation, it is equivalent to rate of return regulation.[4] However, he maintains that the years 2002-2005 can be characterized as CPI-X regulation because the 2001 rates are adjusted using a formula that includes growth in the CPI and an X-factor. He therefore

[4] *Most notably, see the exchange in the Transcript Proceedings, page 395, lines 1 through 7.*
Dr Griffith: What I suggest to you is that the building block approach, as outlined in the price determination, and also even in the first paragraph of the comments which I've handed to you, is to express to the point of the fixing the price for the first year (is) a rate of return regulation approach. If you stop right there without any of the future variations, is that right?
Dr. Makholm: That's correct.

concludes that when viewed as a whole, the Price Determination is consistent with the mandate to use CPI-X regulation.

I believe that this conclusion is insupportable. It is self-evident that the Tariff Order prohibition against using rate of return regulation must be satisfied in every year, not just in some years. Moreover, the 2001 price decrease accounts for the lion's share of the (real) change in prices over the 2001-2005 price control period. Even under the Re-Determination, TXU's prices are to decline a nominal 18.4% in 2001, and would fall an additional one percent in real terms in each of the following four years. Over 80% of the 2001-2005 real price declines therefore take place in the first year of this period. This implies that, according to Dr. Makholm's own testimony, over 80% of the real price declines in the Price Determination result from the application of rate of return regulation rather than CPI-X regulation.

I also reject the conclusion that paragraphs (a) and (b) of clause 5.10 are logically inconsistent unless tariffs are linked directly to a company's own costs and returns. In fact, the opposite conclusion is more sensible. If the Tariff Order was motivated by a desire to have tariffs expressly track each DB's own costs, it would *not* contain paragraph (b) as it is written.

Paragraph (b) states that, if and when asset values are used in future rate determinations, the ORG must utilize "the adjusted asset value for that Distributor as at 1 July 1994," subsequently adjusted for inflation, depreciation and asset disposals. It is clear from the table that these adjusted asset values differ from the assets' optimized depreciated replacement costs (ODRC). The difference is a regulatory adjustment that is positive for the three largely urban DBs and negative for the two predominantly rural DBs. Since the ODRC asset values represent the economic value of these assets, the regulatory adjustments are expressly designed to cause rates to *diverge* from those that would be associated with each company's own costs.

These regulatory adjustments were designed to achieve public policy objectives when Victoria's electric power industry was restructured. This is evident in the Department of Treasury document *Reforming Victoria's Electricity Industry*, which explains the rationale for the adjusted asset values for each DB.

> Government policy has been to ensure minimal differentials in delivered electricity prices between similar customers in metropolitan areas and rural and farm customers. This has been principally achieved by the following measures:
>
> writing down the value of assets in rural areas in the two rural based DBs (Eastern Energy and Powercor): and writing up the value of assets in the three metropolitan DBs by a corresponding amount to the rural asset value write down.
>
> The asset write down is equivalent to a substantial once-off subsidy to rural and farm customers, ensuring electricity pricing parity with urban customers.[5]

Regional pricing objectives therefore led to the establishment of adjusted asset values. The Treasury document does not say that the fixed asset values are needed so that DB prices reflect their own costs. Indeed, asset values are adjusted to insure that prices diverge from actual costs in pursuit of other public policy goals. These goals would not have been achieved if each DB's rates were linked only to its own costs.

Therefore, it is my opinion that paragraph (b) is properly interpreted as a requirement that, in future price determinations, the ORG must respect the Government's objectives for regional price equity. This provision does not support the view that each company's own costs and returns must be used when re-setting prices. In fact, the practical effect of this paragraph is to drive a wedge between each distributor's costs and its allowed prices.

I also disagree with the contention that paragraphs (a) and (e) of Clause 5.10 are redundant. Every other part of Clause 5.10 is dedicated towards achieving different, but complementary, goals. It strains credulity to conclude that paragraph (e) would be separately enumerated if it was implicit in the broader mandate to use CPI-X regulation.

Finally, it is noteworthy that Clause 5.10 nowhere states that when updating price controls, the ORG must examine utility returns or insure that DB prices do not reflect "monopoly rent." The absence of such a provision is significant. Clause 5.10 would almost certainly require regulators to examine utility returns if legislators viewed the elimination of monopoly rent as a significant objective. Not only does the Tariff Order not include such a provision, it prohibits the use of rate of return regulation which creates direct and explicit links between utility rates and allowed returns.

[5] Office of State Owned Enterprises, Department of the Treasury, *Reforming Victoria's Electricity Industry*, Section 10.5, December 1994, p. 81.

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III. Distinction between Price-Based CPI-X Regulation and Rate of Return Regulation

The "Fork in the Road"

In both his written report and oral testimony to the Appeal Panel, Dr. Makholm said that rate of return regulation can be distinguished from price-based regulation (synonymous with CPI-X regulation, in his view) on the basis of three factors:

- *The period between rate cases*: price-based regulation sets definite, pre-established periods between examinations of utility cost (or rate cases); there is no fixed period between rate cases under rate of return regulation.
- *Adjustment of prices*: in price-based regulation, prices adjust between scheduled rate cases according to a formula. The formula itself has a CPI (or other) inflation measure and an X-factor, and may also have an adjustment reflecting changes in service quality. Under rate of return regulation, prices are fixed between rate cases and are adjusted only at the time of a new rate case.
- *Adjustment of tariff structure*: in price-based regulation, utilities are permitted to adjust the structure of their tariffs; such adjustments are not permitted under rate of return regulation.

Dr. Makholm further claims that, either individually or as a group, these three features (fixed periods between rate cases, automatic price adjustments, and changes in tariff structures) are *never* associated with rate of return regulation. Hence there is a clear "fork in the road" between rate of return and CPI-X regulation. Any form of regulation that has either a fixed period between rate cases, adjusts prices over time according to a formula, or allows for tariff flexibility cannot reasonably be characterized as rate of return regulation.

At the same time, Dr. Makholm believes that rate of return and price-based regulation share certain features. The most important such feature is the regular examination of utility cost. This is purportedly "universal" in all regulatory systems.

Relatedly, under all forms of regulation, regulators must ensure that utility rates are not characterized by the extraction of monopoly rent.

While there is some truth in Dr. Makholm's description of both rate of return and CPI-X regulation, he goes too far in claiming that these regulatory alternatives can always be distinguished on the basis of the three listed features. Accordingly, these characteristics do not constitute a "fork in the road," and it is not sufficient to consider whether a regulatory approach includes any of the three listed features in order to determine whether this type of regulation is compatible with price-based CPI-X regulation. Consider the following examples, all of which have been implemented under cost of service ratemaking.

Fixed Periods between Rate Cases

Rate of return regulation can feature fixed, pre-established periods between cost of service rate cases. One prominent example comes from California. Prior to the implementation of performance-based regulation (PBR) in the state, there was a regular, three-year cycle between general rate cases (GRCs). GRCs therefore took place once every three years, and this cycle was set and known in advance. This system was in place for the state's major electric utilities for a decade or more before PBR was implemented.

Commissions also often approve multi-year rate freezes in the context of merger agreements. That is, in mergers between two companies whose rates remain subject to cost of service regulation, Commissions often freeze the rates of the companies for set periods of time. These companies therefore know that they cannot and will not be subject to rate hearings or demands to adjust their rates for a set number of years.

There have been numerous merger-related rate freezes, but one particularly revealing example is for the 1998 merger between two Massachusetts energy companies, Eastern Enterprises and Essex County Gas Company. These companies' merger proposal included a ten-year rate freeze. The state's labor unions intervened in this proceeding, and argued that the proposed rate freeze constituted a form of PBR, and thus should be subject to certain constraints specified in Massachusetts law. The unions claimed that the 10 year rate freeze was a form of PBR since rates would not be subject to traditional rate of return regulation during this ten year period and the companies would be allowed to retain any savings achieved over this period.[6]

The Massachusetts Department of Telecommunications rejected this claim. It wrote

> With respect to the issue of whether the Rate Plan is a PBR, we note that a PBR is a substitute for traditional cost of service regulation. Although the proposed Rate Plan contains features that can create incentives similar to those found in PBRs, a PBR is far more complicated. A PBR typically features annual filings based on a predetermined formula that takes into account an inflation factor, analyses of industry productivity compared to economy-wide productivity, and consideration of whether there should be an earnings sharing mechanism. Since the proposed Rate Plan does not include either an inflation factor or an analysis of industry productivity, there will be no change to the traditional cost of service regulation by which the Department currently regulates the rates of Essex. The proposed Rate Plan is better analogized to rate settlements approved in the past by the Department, whereby a company agrees not to file a rate case for a specified period of time. Therefore, despite some similar elements, the Department finds that the Rate Plan does not constitute a PBR (legal case citations omitted).[7]

This passage states unambiguously that prolonged rate freezes are compatible with cost of service regulation. Indeed, the DTE claims that this case is not out of the ordinary, since it has approved a number of multi-year rate settlements "whereby a company agrees not to file a rate case for a specified period of time."

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[6] *The Unions also listed another reason for why the rate freeze qualified as PBR, although it is of limited relevance in the current proceeding. The Companies presented evidence that the ten year rate freeze would save Essex customers $33 million over the ten-year term of the plan in terms of foregone rate increases which it would be allowed to recover under future rate cases. The Unions claimed that, because of these benefits, the rate freeze tended to align the interests of shareholders and customers, which is an objective of PBR; see the Massachusetts Department of Telecommunications and Energy, D.T.E. 98-27, p. 12.*

[7] *DTE, op cit, p. 16.*

The DTE also says that that PBR is a substitute for cost of service/rate of return regulation. In terms of differentiating between these regulatory approaches, the DTE rejects the claim that a prolonged rate freeze is sufficient for PBR. This point is important and relevant for Victoria, for the ORG and its advisors contend that having fixed periods between rate reviews is evidence that the Determination utilizes price-based CPI-X regulation and therefore complies with the Tariff Order.

Price Adjustments between Rate Cases

Prices are sometimes adjusted between rate cases under rate of return regulation. For example, it is the norm for fuel costs, which are a large component of retail gas and electricity prices, to be adjusted more frequently than "base rates," which recover non-fuel costs. Fuel-related components of customer prices are often adjusted annually or more frequently to pass through changes in utility fuel costs. These price adjustments often take place through relatively automatic mechanisms and do not feature full-blown cost of service reviews.

While less common, base rates can also be updated between rate cases. In California, for example, so-called attrition rate adjustment (ARA) mechanisms were used to adjust base rates between scheduled general rate cases (GRCs). The California Public Utilities Commission (CPUC) defines an ARA as a mechanism that:

> adjusts base rates in the years between general rate decisions to offset most of the effects on earnings of financial and operational attrition. Labor expenses and nonlabor maintenance and operational expenses are indexed, and a fixed amount is allowed to recover expenses related to depreciation, income taxes, financing costs, rate base growth, and other items. The ARA improves the company's ability to earn its authorized return in the years between general rate cases.[8]

[8] *Decision 85-12-076, California Public Utilities Commission, December 18, 1985, Appendix B, page 2. Interestingly, this description of the purpose of the ARA is similar to what Dr. Makholm claims was one of the motivating factors for price cap regulation – to maintain company earnings during inflationary times without having to have frequent rate cases; see the Transcript Proceedings, p. 343, lines 11-18.*

This definition clearly states that attrition mechanisms are designed to adjust rates between GRCs. As previously noted, in the years prior to PBR, California operated under a three-year rate case cycle.[9] Thus there was a regular pattern of a GRC, followed by two attrition years, followed by another GRC. The attrition years applied index-based adjustments to the company's own operation and maintenance (O&M) costs. There were also mechanisms designed to recover the company's own capital costs during the attrition years. For example, during the 1987-89 rate case cycle for Pacific Gas and Electric, rate base adjustments during the 1988 and 1989 attrition years were equal to the company's seven-year average of construction costs over the 1981-87 period.[10]

These methods are similar to those used by the ORG in the Determination. Like the ORG, the CPUC linked rates to the company's own costs over the relevant regulatory period. Indexing methods were used to adjust revenue requirements over the years, and rates were updated accordingly. There are, of course, also differences between the approaches. For example, the ORG uses a five rather than three-year rate case cycle, includes an efficiency carry-over, employs more elaborate capital spending forecasts, and allows projected revenues to be realized via a CPI – X indexing formula. These differences are relevant in terms of the complexity of the ratemaking regime and the incentives it establishes. Fundamentally, however, the ORG uses similar methods for establishing allowed revenues over a multi-year period as did the CPUC in the 1980s.[11]

There is also no question that California's ARA mechanisms were part of an explicit cost of service/rate of return regulatory system. The ARA was embedded in a three-year cycle of regular GRCs, which are the foundation of cost of service ratemaking. The CPUC formally broke with this system when it adopted PBR. The similarities

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[9] In 1984, California's energy utilities switched form a two-year to a three-year rate case cycle, which was maintained until industry restructuring and PBR in the mid-90s. The beginning date for when regular two-year cycles were implemented varies somewhat by company.

[10] I. 86-07-032, CPUC.

[11] This view is supported by Dan Fessler, a former member of the CPUC; for example, see the letter from Dr. Fessler to Dr. Tamblyn on the ORG website.

between the Price Determination and the CPUC's previous approach further supports the view that the Determination employs rate of return regulation and not the "price based" regulation mandated by law.

It is also interesting that the CPUC believed that its GRC-attrition ratemaking approach did create some positive incentives. Incentives were inherent in the regulatory lag between rate cases. The CPUC writes that under its approach,

> …we are extending to utility management an opportunity and incentive to find ways to conduct operations for less than projected. When it can do this it flows the benefit to the utilities bottom line, which means profit. In the short term, between general rate case proceedings, the shareholders benefit when the company's management can "do it for less," and correspondingly, ratepayers ultimately benefit because the productivity improvement will be reflected periodically when there is a comprehensive review of the utility's revenue requirement. Keeping this incentive for utility management is a cornerstone of ratemaking, which leads us to look askance at proposals for immediate "givebacks" of all cost savings to ratepayers.[12]

It must be emphasized that this passage applies to incentives created under rate of return regulation, but it is nearly identical to Dr. Makholm's description of the incentives that would be generated under the ORG's Determination. It would be surprising if the mandate to use price-based CPI-X regulation was designed merely to replicate the incentives that exist in practice under rate of return regulation. The Tariff Order is almost certainly intended to improve on rate of return ratemaking. In my opinion, the fact that the Determination employs similar methods and creates comparable incentives as some cost of service regulatory regimes is further evidence that this Determination is not consistent with the Tariff Order.

Tariff flexibility

Tariff flexibility is sometimes allowed under rate of return regulation. The most common example is rate discounting to price-sensitive customers. There are several examples of US states that have allowed such rate discounting under cost of service

[12] D. 85-03-042, p. 6.

regulation. Discounting enables some adjustment of the tariff structure at company discretion.

In some cases, revenue losses from tariff discounts can be recovered from remaining customers. For example, the Illinois Commerce Commission has allowed Northern Illinois Gas, Illinois-American Water Company, and Consumers Illinois Water Company to recover revenues lost from discounting from other customers. The combination of rate discounting to certain customers and rate recovery from other customers introduces considerable flexibility in tariff structure, even as revenues remain unchanged.

The Importance of External Performance Standards

In light of the conflicting evidence above, the three features listed by Dr. Makholm cannot be used to distinguish rate of return regulation from price-based CPI-X regulation. However, one factor that is critical for making this distinction is the use of external performance standards in ratemaking. External standards are not unique to price-based CPI-X regulation. For example, some utilities have operated under targeted incentive mechanisms where they can be rewarded depending on the relationship between their unit cost of service and a measure of the industry's unit cost.[13] These plans utilize external performance benchmarks but do not include specific CPI-X indexing formulas. In light of these examples, it is not true that ratemaking which uses external benchmarks is sufficient for price-based regulation.

But while external performance standards are not sufficient for price-based CPI-X regulation, in my opinion they are a *necessary* feature. The importance of external performance in price-based CPI-X regulation is supported by both theory and practice.

The theoretical rationale comes from what is sometimes termed the "competitive market paradigm." In competitive markets, prices do not depend on the costs of any specific company. Rather, prices will change at the same rate as trends in the *industry's* unit cost. Prices in competitive markets are therefore linked to measures that are external to the performance of any individual company. If an indexing mechanism is to "price based," it must embody this feature.

There are also many CPI-X regulation plans that use external performance measures as the primary basis for allowed price changes. In fact, it is the norm for the parameters of North American indexing plans to be calibrated using external performance measures rather than the company's own costs. In many of these plans, external performance standards like industry total factor productivity (TFP) growth are incorporated directly into the indexing formula.

The importance of external performance standards in PBR is widely acknowledged by North American regulators. One example comes from the previously cited merger in Massachusetts. In evaluating whether a ten-year freeze qualified as PBR, the DTE considered whether evidence was presented on industry productivity. The DTE concluded that "since the proposed rate plan does not include either an inflation factor or an analysis of industry productivity, there will be no change to the traditional cost of service regulation by which the Department currently regulates…"[14] Industry productivity is an external performance measure. Hence in ruling that a prolonged rate freeze did not constitute a departure from traditional rate of regulation, a principal reason was that the new plan did not make use of external performance standards.[15]

The California Public Utilities Commission has also written about the role of external performance measures in departing from traditional cost of service regulation.

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[13] *Examples include the "MERIT" plans approved for Niagara Mohawk Power and NMGas*

[14] *DTE, op cit, p. 16.*

[15] *The other reason explicitly mentioned was that the plan did not utilize an inflation measure. This reason supports one of the factors cited by the ORG and Dr. Makholm: that inflation-based rate adjustments often signal a departure from traditional regulation.*

For example, when approving the most recent PBR plan for San Diego Gas and Electric, the CPUC writes that

> We have long considered incentive-based ratemaking superior to command-and-control regulation. PBR mechanisms send the important message that minimizing costs without sacrificing service quality and reliability can result in greater rewards with "less" regulation than traditional cost-of-service regulation. In order to provide these incentives, we must necessarily break the link between rates and costs. Cost of service regulation uses the utility's own costs in setting rates…(emphasis added)

The meaning of this statement is clear. According to the CPUC, the primary distinction between cost of service regulation and PBR is that the former approach uses the company's own costs to set its rates, while the latter necessarily breaks this link. Indeed, in California's case, this is the primary difference between PBR and the previous cost of service regime. Recall that under its GRC-attrition approach, California employed both fixed rate case cycles and adjusted rates between rate reviews. Dr. Makholm argues that these features are observed only in CPI-X regulation. However, the CPUC has not highlighted these factors when distinguishing between cost of service regulation and PBR, while it has emphasized the importance of external performance standards.

In my opinion, this evidence further demonstrates that the Determination is not compatible with the Tariff Order. External performance measures are necessary, but not sufficient, for implementing price-based CPI-X regulation. By failing to use external performance measures, the Determination did not comply with this mandate.

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IV. THE "UNIVERSALITY" OF COST OF SERVICE RATE CASES

According to the ORG, one of the continuities between CPI-X and rate of return regulation is the need to review company costs. This is purportedly a "universal" feature of regulatory regimes. If this premise is accepted, the Determination's building block approach does not necessarily violate the prohibition against rate of return regulation since examining company returns will inevitably be part of any regulatory review.

These assertions are not true. CPI-X regulation does not *always* review company costs when indexing plans are updated. Many CPI-X indexing formulas for North American have been updated using information other than the costs of the regulated company. I briefly describe four examples, each of which is interesting in its own right: the Local Exchange Carriers (LECs) subject to the jurisdiction of the Federal Communications Commission (FCC), US West-North Dakota, NYNEX-Rhode Island and NYNEX-Maine.

LECs subject to FCC jurisdiction The FCC updated the price cap plan for the LECs subject to its jurisdiction in 1997. The X factor selected for this plan depended entirely on industry trends in TFP and input prices. The updated plan also eliminated an earnings-sharing mechanism that was included in the original plan. The FCC made it clear than one of the reasons it abandoned earnings sharing was to implement "pure" price regulation and to break with rate of return regulation. This is evident in the opinion expressed by one of the Commissioners, who wrote:

> I am particularly pleased that this Report and Order puts a stake through the heart of "sharing," the requirement that incumbent LECs earning more than specified rates of return must "share" half or all of the amount above those rates of return with their access customers in the form of lower rates in the following year. Since sharing continues the inefficiencies of a rate-of-return era, I have

> long believed that a system of pure price caps without sharing would be preferable.[16]

This statement does not support the claim that North American regulators recognize the necessity of cost of service/rate of return principles when updating PBR plans. Here, the FCC makes a clear distinction between implementing its preferred approach of "pure price caps" and a past "rate of return era." In my opinion, this is precisely the distinction envisioned in the Tariff Order mandate to use price-based CPI-X regulation and not rate of return regulation.

US West North Dakota The price-indexing plan for US West-North Dakota has been in effect since 1989. This plan is updated biannually according to formulas specified in legislation. The Commission has never used the company's earnings to set rates at the time the plan is updated.

NYNEX-Rhode Island[17] The NYNEX-Rhode Island plan was updated in 1996 and 2000. Neither of these updates featured cost of service reviews. The Company's earnings have also been quite healthy during this period. Contacts at the Rhode Island Commission indicate that the company's return on equity was 18.5% in 1998 and 20.5% in 1999. While these earnings levels are almost certainly in excess of the company's cost of capital, they have not prompted cost of reviews that re-set revenues to be equal to costs.

NYNEX-Maine NYNEX-Maine represents a particularly interesting case. It operates under a PBR plan that features index-based price adjustments. In the most current review of this plan, the Public Advocate in the state filed a Motion with the Commission requesting that the review of this plan include a cost of service rate case to establish revenue requirements. The Commission considered this request from two standpoints: its legal requirements under the legislation authorizing "alternative forms

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[16] Separate Statement of Rachelle B. Chong, *Fourth Report and Order*, CC Docket 94-1, May 7, 1997, FCC97-159, p. 2.

of regulation" (AFORs *i.e.* alternatives to traditional cost of service regulation); and optimal public policy. Under both criteria, the Commission rejected the request for a cost of service rate case. The extended quote below explains the Commission's reasoning.

> We will address two separate questions. The first is whether the AFOR statute, in particular 35-A M.R.S.A 9103(1), requires the Commission to reset the Company's rates pursuant to a new revenue requirement finding each time it extends and existing alternative form of regulation (AFOR) or establishes a new AFOR. Assuming that we are not required by law to conduct a revenue requirement proceeding and to reset rates based on the findings of that proceeding, the second question is whether we should conduct a revenue requirements proceeding as a matter of discretion. The answer to both of these questions is no.
>
> ...If the Commission does adopt an AFOR, section 9103(1) states that the Commission must take some action to ensure that ratepayers are not paying more for basic local exchange service than they would have paid in the absence of an AFOR, but section 9103(1) does not specify the action that the Commission must take. Nothing in that subsection expressly requires a resetting of rates; such a requirement also cannot be necessarily implied. Nothing in the subsection precludes the Commission from ensuring the condition by means other than a revenue requirement proceeding *e.g. through the form of regulation itself* ...(emphasis added)
>
> Section 9103(1) also states that an AFOR may "not be less than 5 years nor exceed 10 years without the affirmative reauthorization by the commission...," thereby granting substantial flexibility to the duration of an AFOR. Under that provision, the Commission could allow an AFOR to run for 10 years, or perhaps even longer, without a resetting or rates to match a currently-determined revenue requirement. During the entire 10-year (or longer) period, a telephone utility could be allowed to "over-earn" (as defined by the Public Advocate) suggesting that the legislature is less concerned with a utility's earning level (or traditional "over-earning") than with the prices that Maine consumers must pay. In fact, the possibility that a utility may earn more than a rate of

[17] *In this and the following example, NYNEX is now known as Verizon.*

return that may be incorporated in a "starting point" for an AFOR serves as the primary incentive under alternative regulation for a utility to be efficient and reduce costs. Absent this incentive, it is possible that under traditional regulation a utility might earn a lower return but have higher prices than under incentive regulation. Although seemingly paradoxical, a higher return under incentive regulation could be accompanied by lower prices. Significantly, the Legislature did not require the Commission to ensure that a telephone utility not earn a greater return under an AFOR. Instead, the law requires the Commission to ensure that prices for basic local service be no higher than under an AFOR.

The Public Advocate also apparently believes that, if the Commission extends the duration of an original AFOR or commences a new AFOR, the statute requires the Commission to begin anew in the same manner that it did for the initial period *i.e.* by conducting a new revenue requirement proceeding. It seems more likely that in authorizing the Commission to establish an AFOR, the Legislature was using the term "alternative form of regulation" in a more general sense. There is no indication that the Legislature intended a series of separate, discrete plans, or that the Commission must set a revenue requirement, and new rates based on that revenue requirement, each time the Commission extends or establishes a new AFOR period.

We now address the question of whether as a matter of policy we should conduct a revenue requirement proceeding. As we explained in the June 20 Order, conducting a revenue requirement proceeding tends to undercut the efficiency incentive. Indeed, knowledge that a revenue requirement proceeding will occur could create a conflicting incentive to allow costs to rise toward the end of an AFOR period so that the test year used to establish the revenue requirement and rates will include those costs. Certainly, there is some question whether any efficiency gains (beyond those mandated by the form of regulation that is in effect) will be passed on to ratepayers in the form of lower prices. Under the AFOR that is now in effect, a benchmark level of efficiency (but not the actual level) is passed on through the operation of the price regulatory index (PRI). We do not agree with the proposition that ratepayers are entitled to all efficiency gains; such an approach surely diminishes or eliminates the efficiency incentive. Of course, the utility does get to keep the financial benefits of any historic efficiency gains, whether under

> "traditional" rate of return or under an AFOR (footnote elevated to main text).[18]

In the current context, this quote contains many important lessons . Like Victoria, the Maine Commission is updating rates with reference to the controlling legislation. Also like Victoria, this legislation does not say that regulated company earnings must or should be used to update rates. The Maine PUC clearly rejects the desirability of updating rates based on the company's own performance. It explicitly distinguishes between a benchmark level of efficiency and the company's own efficiency, and says that the former should be used if strong performance incentives are to result. Indeed, the Commission contemplates a period of 10 years or more of "over-earning" provided that this situation creates sufficiently strong incentives so that customers are also better off.

The Commission believes that cost of service reviews are not necessary if the "form of regulation itself" creates sufficient benefits for customers. The PUC clearly believes that the most important feature of the form of the regulation is the establishment of a benchmark level of efficiency, rather than the company's own efficiency, within the price control formula. This is critical for creating the type of incentives necessary for customers to benefit and eliminate the need for a rate case.

This is relevant for Victoria because, if anything, the Maine legislation presents a more compelling case for the need for ongoing cost of service reviews. Unlike Victoria, the Maine law requires that AFORs produce lower rates than would be the case in the absence of an AFOR. The absence of an AFOR is, by definition, traditional cost of service regulation. Parties can therefore reasonably argue that this legal provision can only be enforced if there are ongoing cost of service rate cases. In fact, the Maine Public Advocate made this argument. Nevertheless, the Maine Commission rejected the need for cost of service rate cases entirely because of the *a priori* theoretical case that external

[18] Maine Public Utilities Commission, Docket No. 99-851, Order on Reconsideration, August 22, 2000.

performance standards, in and of themselves, create stronger performance incentives that in the long run benefit all parties.

These examples demonstrate that cost of service reviews are not inevitable, and that regulators have adopted pure, price-based CPI-X regimes.[19] These plans have been implemented because of the belief that the stronger performance incentives that result benefit customers in the long run. I believe this result is also what is contemplated under the Tariff Order .

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[19] *In North America, there are fewer applications of PBR for energy utilities, and it is difficult to compare energy PBR plans approved for the same utility because of the ongoing restructuring of the US electric power industry. For example, the vertically-integrated operations of San Diego Gas and Electric (SDG&E) were subject to PBR from 1994 to 1999, but during this time competition was introduced into California's electric power industry and power transmission and distribution operations were unbundled. Thus when the CPUC updated SDG&E's PBR plan, the new plan applied to distribution only. Because of complications like this, there are to date few, if any, "apples to apples" updates of PBR plans for energy utilities.*

However, regarding the necessity of cost of service rate reviews, one recently adopted plan for a US energy utility is worth noting. Bangor Gas is a newly-established gas utility in Maine. Its gas delivery rates will be subject to an indexing mechanism. This company's gas delivery rates have never been subject to a cost of service review, and the initial rates established for this company were not based on the company's costs or operations. Instead, initial gas delivery rates were equal to the difference between the retail (delivered) price of heating oil and the company's cost of purchasing gas. Since heating oil is a close substitute for natural gas in Maine, initial rates are based on a competitive market proxy rather than the company's own cost of service. This is a very strong application of the competitive market paradigm for setting rates. Nevertheless, the indexing plan for Bangor Gas cannot be characterized as an example of a pure price-based CPI-X regulation because there is an earnings-sharing mechanism.

V. Practical Options for Complying With the Tariff Order

Some parties have argued that it is difficult to implement external regulation in Victoria at the present time. The main concern is the lack of data. The DBs have been in their current form for only about five years, and this limits the amount of data available to compute external performance measures.

The lack of data in Victoria does create challenges, but I believe that there are feasible options for implementing genuine price-based, CPI-X regulation in Victoria that complies with the Tariff Order. The best alternative in my opinion is a "rolling X-factor." Under this approach, the X-factor would be based on industry TFP trends for all five distributors in the State. As others have noted, there is probably not enough data at present to compute the long-run industry TFP trend with confidence. But new TFP data can be computed during the 2001-2005 period, and this data can be reflected in the X-factor as it becomes available. For example, industry TFP trends can be updated annually, and the X-factor can be equal to a moving average of TFP trends.

This approach has notable advantages compared with the Determination. It would phase in performance gains from the previous regulatory period, but prices would reflect *industry* trends rather than each company's individual performance. This method therefore creates stronger incentives and is clearly consistent with the Tariff Order prohibition against using rate of return regulation. This type of approach has also been employed in an indexing plan that applies to Class I US railroads.

A second option would be to utilize data from overseas until sufficient data are available in Victoria. For example, TFP trends for US power distributors could be computed and employed as proxies for the long run TFP trend in the industry. This approach is clearly feasible, but it also has obvious drawbacks compared with methods (such as a rolling X-factor) that rely on the Victorian data that do exist. For example, it is not clear that the US TFP trends are appropriate for Victoria, since US investor-owned utilities have long been private enterprises while the Victorian distributors were only recently privatized. Victoria's industry may have therefore experienced more rapid TFP gains in recent years by eliminating inefficiencies that were inherited from the previous State-owned structure. Thus while overseas data should be employed cautiously, they are nevertheless a valuable source of information and worthy of consideration.

ESSENTIAL SERVICES COMMISSION APPEAL PANEL

E5/2005

IN THE MATTER of the Electricity Price Determination 2006-2010 in respect of Powercor Australia Ltd

AND

IN THE MATTER of the *Essential Services Commission Act 2001* (Vic)

AND

IN THE MATTER of an appeal by Powercor Australia Ltd

Statement of Lawrence Robert Kaufmann
Labour Allocation

I, Lawrence Robert Kaufmann, Economist, of 22 East Mifflin Street, Suite 302, Madison, Wisconsin in the United States of America say:

1. I am a Partner at Pacific Economics Group LLC (***PEG***). PEG has provided consulting services to the Essential Services Commission (the ***Commission***), in the undertaking of the Electricity Price Determination 2006-2010 by the Commission.
2. I am an economist by profession, having graduated in 1984 with a Master of Arts degree in Economics from the University of Missouri and in 1993 with a Ph.D. in Economics from the University of Wisconsin. My full curriculum vitae is annexed hereto and marked 'LK1.'
3. In December 2004, PEG wrote a report 'TFP Research for Victoria's Power Distribution Industry' for the Commission (the ***PEG Report***). The letters 'TFP' stand for Total Factor Productivity. That Report is exhibited as 'LMP4' to the witness statement of Lovelyn Maria Parker filed on behalf of Powercor Australia Ltd. (***Powercor***).
4. The PEG Report contains, at Table 5 , a table headed 'O&M Input Price Sub-Indexes and Company Accounts.' That table shows the various input price sub-indexes that were used to construct the overall price index for operation and maintenance inputs, as well as the mapping of these subindexes to different operation and maintenance cost categories. The table also shows weights that are applied to each of the subindexes.

5. Table 5 is also broken into five columns, one for each of the distributors and a total industry column. Each column lists expenditures across a range of operating expenditure (opex) cost categories and assigns a particular price subindex to each category.

6. I was the person responsible for the calculation of the percentage of labour in Powercor's operational expenditure as set out in Table 5 of the PEG Report.

7. Operational expenditure of power distributors includes the purchase of both labour and non-labour inputs.

8. Power distributors in Victoria do not report their labour and non-labour opex separately.

9. To measure industry total factor productivity and input price trends, I developed a price index for distributors' overall opex (ie for both labour and non-labour expenditures). I used the indexes published by the Australian Bureau of Statistics (***ABS***) to the extent that those indexes were applicable to this purpose.

10. I constructed the opex input price index in the following way:

    (a) First, I examined major sources of distributors' operating and maintenance expenditures as reported in their regulatory accounts;

    (b) Next, I assigned the appropriate price subindex from the Australian Bureau of Statistics to the relevant operating expenditure category as follows:

Opex Cost Category	**ABS Price Index**
Meter data services	Producer price index
	(PPI) computer services
Billing and revenue collection	PPI computer services
Advertising/marketing	PPI advertising services
Customer service	PPI secretarial services
Regulatory	PPI legal services
Other operating	PPI business services
SCADA maintenance	PPI computer services
Network operating costs	Labour cost index
All other maintenance costs	Labour cost index

    (c) For network operating costs and all other maintenance costs, I determined that the labour cost index was the appropriate price index to apply.

    I then reviewed the published operation costs of the distribution industry for the year 2003 (the most recently available year at the time the PEG report was prepared) and constructed an overall operating expenditure input price index as a weighted average of each of the sub-indexes listed above. To do this, I had regard to Powercor's share of the operating expenditure category in the power distribution industry's overall opex.

11. I used this process of determining input price calculations to develop an estimate of the share of labour as a component of the distributors' overall operational expenditure.

12. I applied the labour cost index to the network operating costs and all other maintenance cost categories. The share of labour in overall opex is therefore equal to the proportion of these two cost categories in overall opex. For Powercor, labour's estimated share of opex is 71%.

Dated 2 December 2005

…………………………………………………….
Lawrence Robert Kaufmann

ESSENTIAL SERVICES COMMISSION APPEAL PANEL

E3/2005

IN THE MATTER of the Electricity Price Determination 2006-2010 in respect of United Energy Distribution Pty Ltd

AND

IN THE MATTER of the *Essential Services Commission Act 2001* (Vic)

AND

IN THE MATTER of an appeal by United Energy Distribution Pty Ltd

Statement of Lawrence Robert Kaufmann
Partial Factor Productivity for Operating Expenditures

I, Lawrence Robert Kaufmann, Economist, of 22 East Mifflin Street, Suite 302, Madison, Wisconsin in the United States of America say:

1. I am a Partner at Pacific Economics Group LLC (***PEG***). PEG has provided consulting services to the Essential Services Commission (the ***Commission***), in the undertaking of the Electricity Price Determination 2006-2010 by the Commission.
2. I am an economist by profession, having graduated in 1984 with a Master of Arts degree in Economics from the University of Missouri and in 1993 with a Ph.D. in Economics from the University of Wisconsin. My full curriculum vitae is annexed hereto and marked 'LK1.'
3. I provided advice to the Commission on the Electricity Price Determination 2006-2010. In particular, I provided advice on the estimation of total factor productivity (TFP) and partial factor productivity (PFP) trends for Victoria's electricity distribution industry. This work was summarized in my December 2004 report *TFP Research for Victoria's Power Distribution Industry*. A copy of this report is annexed hereto and marked 'LK2.'
4. The Commission used my work on the industry's change in operating expenditures (opex) PFP as an input into what it calls the "rate of change" calculation. This rate of change is used to roll forward each company's past opex to 2006. For United Energy, the Commission applied the rate of change calculation to the average value of the company's opex between 2000 and 2002.

5. I confirm that I have been provided with a copy of the Victorian Supreme Court Expert Witness Code of Conduct and that I have read and agree to bound by the Code. I have made all the inquiries which I believe are desirable and appropriate and that no matters of significance which I regard as relevant have been withheld from the Appeal Panel.

Partial Factor Productivity Basics

6. Partial factor productivity is a measure of the efficiency of a given input, or set of inputs, that are used in production. Changes in PFP therefore refer to changes in the efficiency with which a given set of inputs are transformed into a change in overall output. PFP changes can be calculated at the level of the individual firm (or non-profit enterprise, such as a government agency), an industry, or a country's aggregate economy. My work for the Commission calculated changes in PFP for Victoria's electricity distribution industry for two broad sets of inputs: capital and opex. Mathematically, changes in the industry's opex PFP are computed as the change in the industry's overall output quantity minus the change in the industry's opex input quantity over a specified time period.

7. In the electricity distribution industry, opex PFP can be extremely variable from year to year. One reason is that electricity distribution output can change significantly from year to year. For example, one important electricity distribution output is customers' peak demand. Peak demand depends largely on the severity of summer and winter weather since this, in turn, directly affects customers' demands for power used in air conditioning and space heating, respectively. The severity in summer and winter weather can obviously change significantly, and unpredictably, from one year to the next. Opex PFP can therefore also change significantly and unpredictably from one year to the next. Because of these unpredictable year to year PFP changes in the electricity distribution industry, PFP trends over longer periods are often more informative than PFP changes in any given year. The longer-term PFP trend provides a better estimate of how industry PFP would be expected to change over a multi-year period.

8. Opex PFP trends in the electricity distribution industry also depend on trends in the industry's operating expenditures. In general, there is an inverse relationship between the rate of change in the industry's operating expenditures and measured PFP growth. All else being equal, faster growth in the industry's operating expenditures will be reflected in slower opex PFP trends for the industry. Alternatively, slower growth in the industry's operating expenditures will be reflected in more rapid opex PFP trends for the industry. This is an intuitive relationship: all else being equal, if an industry has slower growth in operating expenditures, it is providing the same amount of output using fewer opex-related inputs. This industry is therefore improving the productivity with which it utilizes opex inputs or, alternatively, improving its opex PFP.

9. Because opex PFP depends on changes in overall operating expenditures, it can be affected differently by changes in spending on different types of opex inputs. For example, in the years immediately before full retail contestability (FRC) was implemented in Victoria, the electricity distribution industry may have had to increase its spending on inputs that were necessary to facilitate FRC. Taken in isolation, these FRC-related expenditures would have decreased the growth in the industry's opex PFP. It is possible, however, that spending on other opex inputs was declining at the same time that spending was being

increased on FRC-related inputs. The industry's opex PFP trend would effectively average the spending changes associated with different opex inputs, so that upwards movements in some costs could be offset by downward movements in other costs.

The Commission's Application of PEG's Opex PFP Research

10. The Commission used my work on opex PFP trends for Victoria's electricity distribution industry as an input into its "rate of change" calculation. The Commission used this rate of change calculation to roll forward observed values for each company's real (*i.e.* inflation-adjusted) operating expenditures to the year 2006. Operating expenditures in 2006 were not observable at the time the Final Determination was made in October 2005. The Commission explains its "rate of change" calculation in Section 6.2.3 of the Final Determination.

11. In the rate of change calculation for each distributor, the Commission used the opex PFP trend for Victoria's entire electricity distribution industry (*i.e.* its five distribution businesses) over the 2000-2004 period. PEG's computation of opex PFP trends relied on opex data provided to it by the Commission and which the Commission referenced in the Final Determination. The Commission considered it important for the PFP trends estimated in PEG's report to be consistent with the costs that were used as the basis for the Final Determination. Industry PFP trends over the 2000-2004 period as computed by PEG would therefore reflect the operating expenditures for Victoria's entire electricity distribution industry that were subsequently referenced in the Final Determination.

Marianne Lourey's Statement on Relevant Costs

12. I have reviewed Marianne Lourey's Witness Statement on United Energy's Relevant Costs, with particular emphasis on the sections after paragraph 44. Ms. Lourey makes several references to the role of partial factor productivity growth in determining United Energy's relevant costs. For example, in paragraph 67 she says "the increase in operating and maintenance expenditure incurred by the distributors over the (2000-2004) period includes additional costs associated with Full Retail Contestability. The increase in costs for Full Retail Contestability is therefore reflected in the growth in the average partial factor productivity." Furthermore, in paragraph 68, Ms. Lourey says "there would be a "double counting" of United Energy's costs if its operating and maintenance expenditure was increased by the growth in the average partial factor productivity, which included the additional costs for Full Retail Contestability, and its expenditure was also specifically adjusted for these additional costs for Full Retail Contestability."

13. These statements by Ms. Lourey are accurate. The rate of change adjustment applied to United Energy uses the opex PFP trend for the entire electricity distribution industry over the 2000-2004 period. This adjustment therefore reflects the industry's overall change in expenditures on Full Retail Contestability over this period. Accordingly, the rate of change calculation implicitly adjusts United Energy's past opex costs to reflect the industry's average change in FRC costs. If the full amount of United Energy's own FRC costs is also added to its past observed costs to determine the company's 2006 opex, there will be a "double counting" of some of these FRC costs.

14. In paragraph 72 Ms. Lourey says “the increase in operating and maintenance expenditure incurred by the distributors over the (2000-2004) period includes additional costs associated with insurance. The increase in costs for insurance is therefore reflected in the growth in the average partial factor productivity.” Furthermore, in paragraph 73, Ms. Lourey says “there would be a "double counting" of United Energy's costs if its operating and maintenance expenditure was increased by the growth in the average partial factor productivity, which included the additional costs for insurance, and its expenditure was also specifically adjusted for these additional costs for insurance.”

15. These statements by Ms. Lourey are accurate. The rate of change adjustment applied to United Energy uses the opex PFP trend for the entire electricity distribution industry over the 2000-2004 period. This adjustment therefore reflects the industry’s overall change in expenditures on insurance over this period. Accordingly, the rate of change calculation implicitly adjusts United Energy’s past opex costs to reflect the industry’s average change in insurance costs. If the full amount of United Energy’s own insurance costs is also added to its past observed costs to determine the company’s 2006 opex, there will be a “double counting” of some of these insurance costs.

16. In paragraph 78 Ms. Lourey says “the increase in operating and maintenance expenditure incurred by the distributors over the (2000-2004) period includes additional costs associated with land tax. The increase in costs for land tax is therefore reflected in the growth in the average partial factor productivity.” Furthermore, in paragraph 79, Ms. Lourey says “there would be a "double counting" of United Energy's costs if its operating and maintenance expenditure was increased by the growth in the average partial factor productivity, which included the additional costs for land tax, and its expenditure was also specifically adjusted for these additional costs for land tax.”

17. These statements by Ms. Lourey are accurate. The rate of change adjustment applied to United Energy uses the opex PFP trend for the entire electricity distribution industry over the 2000-2004 period. This adjustment therefore reflects the industry’s overall change in expenditures on land tax over this period. Accordingly, the rate of change calculation implicitly adjusts United Energy’s past opex costs to reflect the industry’s average change in land tax costs. If the full amount of United Energy’s own land tax costs is also added to its past observed costs to determine the company’s 2006 opex, there will be a “double counting” of some of these land tax costs.

18. In paragraph 83, Ms. Lourey says “the increase in operating and maintenance expenditure incurred by the distributors over the (2000-2004) period includes any additional costs associated with a regulatory price review and it would be expected that such costs would have been incurred in 2004. Any increase in costs as a result of the price review should therefore be reflected in the growth in the average partial factor productivity.” Furthermore, in paragraph 84, Ms. Lourey says “there would be a "double counting" of United Energy's costs if its operating and maintenance expenditure was increased by the growth in the average partial factor productivity, which included the additional costs for the price review, and its expenditure was also specifically adjusted for these additional costs for the price review.”

19. These statements by Ms. Lourey are accurate. The rate of change adjustment applied to United Energy uses the opex PFP trend for the entire electricity distribution industry over the 2000-2004 period. This adjustment therefore reflects the industry's overall change in expenditures on regulatory price reviews over this period. Accordingly, the rate of change calculation implicitly adjusts United Energy's past opex costs to reflect the industry's average change in regulatory price review costs. If the full amount of United Energy's own costs of a regulatory price review is also added to its past observed costs to determine the company's 2006 opex, there will be a "double counting" of some of these regulatory price review costs.

20. In paragraph 90 Ms. Lourey says "the increase in operating and maintenance expenditure incurred by the distributors over the (2000-2004) period includes any additional costs associated with restructuring. Any increase in costs associated with restructuring is therefore reflected in the growth in the average partial factor productivity." Furthermore, in paragraph 91, Ms. Lourey says "there would be a "double counting" of United Energy's costs if its operating and maintenance expenditure was increased by the growth in the average partial factor productivity, which included the additional costs associated with restructuring, and its expenditure was also specifically adjusted for these additional costs."

21. These statements by Ms. Lourey are accurate. The rate of change adjustment applied to United Energy uses the opex PFP trend for the entire electricity distribution industry over the 2000-2004 period. This adjustment therefore reflects the industry's overall change in expenditures on restructuring over this period. Accordingly, the rate of change calculation implicitly adjusts United Energy's past opex costs to reflect the industry's average change in restructuring costs. If the full amount of United Energy's own restructuring costs is also added to its past observed costs to determine the company's 2006 opex, there will be a "double counting" of some of these restructuring costs.

22. I also note that the Commission has used the industry's average PFP trend over the 2000-2004 period to roll forward United Energy's past opex to 2006, while United Energy recommends that PFP changes in each year be used to roll forward observed opex to 2006. I believe the Commission's approach is more reasonable, because opex PFP can be extremely variable from year to year. Accordingly, opex PFP trends that are observed over a multiple year period provide a more reliable basis for projecting opex costs forward than the year-to-year changes in opex PFP.

Dated 16 January 2006

Lawrence Robert Kaufmann ……………

Lawrence Robert Kaufmann

Non-Capital Costs in the Access Arrangement for Envestra: Report to the Essential Services Commission of South Australia

Pacific Economics Group, LLC
Economic and Litigation Consulting

Non-Capital Costs in the Access Arrangement for Envestra: Report to the Essential Services Commission of South Australia

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1. Introduction and Summary

1.1 Introduction

The Essential Services Commission of South Australia (ESCOSA) is currently undertaking a review of the access arrangement (AA) for Envestra's gas distribution services in South Australia. This review will set allowed changes in gas distribution prices based on ESCOSA's assessment of Envestra's required revenues over the term of the upcoming AA. One component of required revenues is non-capital costs. The Gas Code allows for the recovery of all Non Capital costs, except for any cost that would not be incurred by a prudent service provider, acting efficiently to achieve the lowest sustainable cost of delivering the reference service.

ESCOSA has issued a Draft Decision which requires Envestra "to remove the 3 percent network management fee from its forecast Non Capital Costs unless it can demonstrate to the satisfaction of the Commission that the inclusion of the management fee is consistent with the Code requirement that the forecast Non Capital Costs achieve the lowest sustainable cost of delivering Reference Services."[1] This management fee (set at three percent of Envestra's regulated gas distribution revenue) is paid to Origin Energy Asset Management (OEAM) in an outsourcing arrangement. ESCOSA's view is that including this fee in non-capital costs is not consistent with the "lowest sustainable cost" of providing service, particularly since Envestra and OEAM are related parties and the contract is not an "arms length" arrangement that has ever been market tested.[2]

Envestra has presented benchmarking evidence which purportedly shows that its non-capital costs are efficient. A September 2005 study from Worley Parsons (WP) concluded that the Company's non-capital costs were reasonable when evaluated relative to similar costs for other Australian gas distributors. In the Draft Decision, ESCOSA examined some of the same benchmarking metrics as those presented in the WP report (*i.e.* non-capital costs per customer and per km of distribution main) but found Envestra's non-capital costs during the first AA were at the upper end of those for comparable

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[1] *Draft Decision: Proposed Revisions to the Access Arrangement for the South Australian Gas Distribution System*, March 2006, Amendment 64, p. 164.

[2] *Draft Decision*, op cit, p. 153. Origin has a controlling interest in OEAM and a 17.5% equity stake in Envestra.

Australian distributors. In response, Envestra submitted a new benchmarking study from Benchmark Economics (BE) which, using different techniques, also concluded that the Company's non-capital costs were efficient. The main difference between the work done for Envestra and by ESCOSA was that the former excluded network development costs from the analysis while the latter did not. Envestra argues that these costs should be excluded because they reflect network specific factors that are beyond management control, especially less favorable weather which reduces the demand for natural gas vis-à-vis many other Australian distributors.

ESCOSA asked Pacific Economics Group LLC (PEG) to provide an independent, objective analysis of the benchmarking evidence presented in Envestra's AA proceeding and the network management fee more generally. PEG has extensive experience with benchmarking energy utilities: we have to date undertaken 56 benchmarking projects for utility or regulatory commission clients in North America, Latin America, the Caribbean, Europe, Asia, Australia and New Zealand. In evaluating the benchmarking evidence and network management fee, we reviewed the following relevant documents:

- *Access Arrangement Information for Envestra's South Australian Network*, a September 2005 document from Envestra summarizing the past AA
- *Review of Gas Access Arrangement for South Australia*, a September 2005 benchmarking study done by Worley Parsons (WP) for Envestra
- *Envestra Limited Capital and Operating Expenditure Review*, a March 2006 benchmarking study done by the Energy Consulting Group (ECG) for ESCOSA
- The non-capital cost section of ESCOSA's March 28, 2006 Draft Decision
- *Benchmarking Non-Capital Costs*, a May 2006 benchmarking study by Benchmark Economics (BE) for Envestra
- *Response to ESCOSA Draft Decision Envestra Access Arrangement*, Part A, chapter 8 (non-capital costs)
- *Response to ESCOSA Draft Decision Envestra Access Arrangement*, Part B, chapter 5 (network management fee)
- *Issues Pertaining to Envestra's Contract with Origin Energy Asset Management*, a June 2006 Expert Witness Statement from Graham Holdaway of KPMG

This report presents our analysis of the network management fee and benchmarking issues. Chapter Two discusses the management fee and Chapter Three considers the benchmarking evidence presented in the proceeding. Chapter Four provides concluding remarks.

1.2 Summary

Outsourcing arrangements between related corporate parties can be a source of production efficiencies but, under any type of cost-based regulation, also raise legitimate regulatory concerns. These concerns can be effectively mitigated if regulated utilities demonstrate that the terms of an outsourcing contract are consistent with the outcome of a competitive market bid. We are not aware of all the details of the Envestra-OEAM contract, but the relevant public documents imply that this agreement was not market tested in this manner either at the time of its inception or subsequently.

The fact that the network management fee is tied to Envestra's regulated revenues is also a source of concern, since both Envestra and OEAM will benefit financially from any regulatory decision that increases regulated cost and, by extension, regulated revenue. Linking management fees to regulated revenues can give OEAM financial incentives to allocate costs and resources in ways that increase Envestra's reported costs above the "lowest sustainable cost" of operations. In the absence of market testing, ESCOSA cannot be assured that this is not occurring unless it has complete information on OEAM's cost and resource allocations, which does not seem to be the case.

Benchmarking evidence could in principle demonstrate that the costs of outsourced services to related parties are efficient. Such evidence could in turn show that consumers are not being disadvantaged by such arrangements, even if they are not market tested. However, any demonstrations of the efficiency of these outsourcing contracts would have to be both rigorous and robust to assuage regulators' legitimate *a priori* concerns about outsourcing contracts between at least partly related corporate parties. At a minimum, rigorous and robust benchmarking would have to be based on high-quality and appropriate data; control for major "cost drivers" that can lead to differences in actual costs among companies; utilize benchmarking techniques that lead to unbiased estimates of the impact of these "drivers" on costs and, by extension, unbiased benchmarking assessments; and make appropriate allowance for the uncertainty that exists in any benchmarking evaluation.

The benchmarking studies presented by WP or BE do not satisfy these criteria. One threshold issue is that these studies exclude network development expenditures from the benchmarked non-capital costs. We agree that network development spending can vary across distributors because of factors beyond company control, but this does not mean these costs must necessarily be excluded from benchmarking studies. Indeed, doing so can distort efficiency assessments because network development spending is expressly designed to increase network utilization, reduce unit costs and thereby improve overall efficiency. Rather than simply excluding these costs, it is preferable to quantify the "exogenous" factors that may influence the optimal level of network development spending for a given distribution system and incorporate these variables into the benchmarking analysis. There was some attempt to do this in the BE study, but the "gas uptake" measure used in this report is clearly not independent of the costs which are the focus of the analysis and hence not appropriate to use in a benchmarking study.

We have other concerns with the benchmarking studies done on behalf of Envestra, including:

- The data used in the WP and BE reports are almost certainly biased in favor of positive benchmarking evaluations for Envestra.
- It is generally not appropriate to evaluate efficiency using a single year of data, as is done in both the WP and BE studies; ESCOSA's examination of multiple years of data is preferable.
- The BE report properly concludes that ESCOSA's benchmarking techniques are simple and can be misleading, but fails to note that the same basic approach was adopted by WP. The BE study represents a step in the direction of greater rigor, but the BE models are still too simple to be an adequate representation of the gas distribution technology. The estimated coefficients in these models are therefore likely to be characterized by "omitted variable" bias. Further efforts and more sophisticated benchmarking techniques are required for robust benchmarking.

- Neither the WP nor the BE study presents a clear criterion for defining or evaluating “efficiency”; the language surrounding this critical concept is so vague and subjective it can be used to justify a wide range of conclusions.
- BE’s discussion of “sustainable cost” is one-sided, and the conclusions regarding cost sustainability cannot be supported given the limited amount of data and analysis.
- The capex econometric cost model presented in the BE report simply has no bearing on the issue of cost allocations and cannot support any conclusion about whether Envestra is or is not shifting costs between operating and capital expenditure budgets.

Given the available evidence, we believe ESCOSA’s decision to require removal of the network management fee when determining allowed costs for Envestra is sound. This network management fee raises legitimate regulatory concerns which would conflict with ESCOSA’s statutory requirements. In principle, performance benchmarking could assuage these concerns, but the benchmarking studies presented in the proceeding are not sufficient for this purpose and do not provide persuasive evidence that Envestra’s non-capital costs, inclusive of the network management fees, deliver the lowest sustainable cost of providing service. If such a benchmarking study was to be done, it would have to use high quality and appropriate data, control simultaneously for the impact of major cost driver variables on gas distributors’ non-capital costs, employ more sophisticated benchmarking techniques, and present rigorous quantitative evidence on the imprecision associated with benchmarking predictions.

Although PEG has not had time to investigate the issue in depth, we believe that such benchmarking evidence could have been provided in this proceeding. Researchers can use bootstrapping and similar methods to develop more robust benchmarking evaluations when there is a relative paucity of data, as in Australia. There is also no reason to restrict the benchmarking analysis to only Australian companies, especially for non-capital cost benchmarking, since high quality data on overseas gas distributors’ non-capital costs and cost driver variables are readily available. These more ample datasets would have allowed more rigorous benchmarking methods to be employed and facilitated more robust benchmarking evaluations. Chapter Three of this report also describes a "competitive market paradigm" which we believe, in combination with rigorous benchmarking evidence, could have been used to demonstrate consistency with the Code's requirement that non-capital costs reflect the lowest non-sustainable cost of providing service.

2. The Management Fee to OEAM

Outsourcing contracts between at least partly related corporate parties are becoming more common. There are several such contracts in Australia's energy utility industries. Similar arrangements have also developed in North America and Europe. In principle, such contracts can lead to economies of scale and scope that reduce the unit cost of utility services. Appropriate outsourcing can therefore be a means of promoting efficiencies that ultimately reduce prices for utility services and thereby benefit customers.

At the same time, outsourcing agreements among partly related corporate parties raise contentious regulatory issues. In Australia, this was perhaps most evident in the 2005 electricity distribution price review in Victoria. The most controversial issue in this review was whether the costs reported in the outsourcing agreement between Alinta Network Services (ANS) and United Energy Distribution (UED) were appropriate for setting the terms of UED's upcoming price controls. The Essential Services Commission of Victoria (ESCV) concluded that the reported costs of this contract were not appropriate and developed a proxy cost measure. UED appealed this issue to an Appeal Panel, which ruled in the ESCV's favor.

The main concern with related party contracts is they create incentives for transfer pricing and cost allocations that raise regulated service prices. For example, when companies operate in both regulated and unregulated sectors, they have clear incentives to shift reported costs from unregulated to regulated operations. The reason is that, under the "building block" approach to CPI-X regulation used in Australia, regulated revenues depend directly on the approved costs of regulated services. Higher allowed costs for regulated services lead to greater regulated revenues. Companies can therefore increase their revenues and profits by allocating more of their "common" costs (*i.e.* costs used to provide multiple services) to regulated operations. This typically cannot be done in more competitive markets. Companies cannot easily "pass on" costs to competitive market customers since they must compete against the price and quality terms of alternative providers.

This may be a salient point for the OEAM-Envestra transaction. Any agreement among affiliated corporate companies will be designed to maximize the profits of the corporation as a whole. These profits can be increased by structuring contracts between different parties (such as OEAM and Envestra) so that costs are shifted towards affiliates where those costs can be recovered more easily. This would necessarily include shifting reported costs from competitive to regulated operations. Similarly, there are incentives to shift costs between regulatory jurisdictions depending on the perceived strength of regulatory monitoring, the timing of regulatory reviews, differences in taxation, and other factors. Recovering a greater share of costs from regulated operations would enable OEAM to offer lower prices and still remain profitable in competitive markets. The terms of the transaction could therefore tend to give OEAM an advantage over rival service providers in the unregulated markets in which it operates or may choose to operate. By the same token, cost-shifting from unregulated to the regulated sectors raises prices for regulated services. This is effectively an exercise of monopoly power, which ESCOSA has a statutory duty to prevent.

The concept that firms have incentives to misallocate costs when they operate in regulated and unregulated markets is well-established in the regulatory economics literature. One representative article on this topic is “Cross Subsidization and Cost Misallocation by Regulated Monopolists,” written by Timothy Brennan for the June 1990 issue of the *Journal of Regulatory Economics.* As explained in this article, “(t)he central concept is that costs of supplying the unregulated market are shifted to the regulated sector. The regulator, hypothetically unable to determine that the shifted costs should be attributed to supplying the unregulated product, increases the revenue requirement that ratepayers of the regulated product must cover…Essentially, costs are misallocated in order to capture monopoly profits otherwise eliminated by regulation. Prices in the regulated market rise, with the attendant profits taken in the unregulated market.”[3]

This article also discusses the importance of regulators having cost information on both unregulated and regulated operations when attempting to determine whether costs

[3] Brennan, *op cit*, p. 37.

have been misallocated. Referring to the monopoly producer as 'M', regulated sales as 'r' and unregulated sales as 'u', Brennan writes

> If cost information is not known to the regulator, producing *u* may give *M* the ability to mislead its regulators about the costs of producing *r*. For example, if sales agents are used to market both *r* and *u*, the agents (or the agents' time) devoted to selling *u* could be attributed by *M* to the sale of *r*. To allocate costs correctly, the regulator has to determine not only that sales agents themselves were necessary to provide *r*, but that *M's* sales agents allegedly spent marketing *r* was not actually devoted to selling *u*. Similar stories could be told about common equipment or financial capital. It is this kind of practice that is referred to when regulators worry about cross subsidization. If *M* can misallocate without limit, *it becomes for all intents and purposes unregulated*. In practice, however, *M's* ability to cross-subsidize will be limited by what the regulator cannot detect.[4] (emphasis added)

These points are relevant for ESCOSA's AA determination. There are incentives to set the terms of the contract between OEAM and Envestra so that costs are shifted towards Envestra's regulated gas distribution services. Under the "building block" CPI-X regulation approach used in Australia, there are only two ways ESCOSA can be assured that such monopoly power is not exercised. The first is the method suggested by Professor Brennan - to obtain cost information from Envestra *and* OEAM that is sufficient to evaluate OEAM's allocation of costs between Envestra and all other sectors it serves. The alternative is evidence that the contract has been "market tested." The terms of a market-tested contract would reflect the outcome of a workably competitive market and thus would not be characterized by monopoly power. Based on our reading of the relevant publicly available documents, it is PEG's understanding that neither of these conditions has been satisfied in the current proceeding.[5]

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[4] Brennan, p. 40.

[5] For example, regarding market testing, in *Response to ESCOSA Draft Decision Envestra Access Arrangement*, Part B, Envestra says the O&M Agreement was not originally market tested in 1997 because "there were no other suitable parties that could have provided the required services" (p. 46). The contract has also apparently not been subject to a competitive tendering process since 1997, even though it has been in place for more than eight years and a number of outsourced utility service providers have become active. Envestra has also apparently not provided details on how OEAM costs have been allocated between Envestra and other entities, in part because "it would be difficult to accurately encompass the number and magnitude of all such services that are recovered through the Network Management Fee. This is partly because such services are derived from OEAM being part of a large vertically integrated company" (*Response to ESCOSA Draft Decision Envestra Access Arrangement*, Part B, pp. 52-53).

The issue most directly relevant to the AA is the network management fee component of Envestra's non-capital costs. ESCOSA has written that it is not clear that this fee is a cost rather than a profit transfer. If it was a profit transfer, ESCOSA believes non-capital costs would be greater than lowest sustainable cost, which conflicts with the requirements of the Gas Code. Envestra provides a detailed response which, among other things, discusses a number of safeguards built into the contract to encourage low costs, such as incentive arrangements for OEAM to pursue efficiency gains, Envestra's contract management rights, and audit assurance.

The provisions of specific outsourcing contracts are complex and idiosyncratic, so such arrangements should be evaluated on a case by case basis. PEG is clearly not privy to all details of the Envestra-OEAM agreement, but several aspects of Envestra's submissions do raise concerns. One basic issue is that the network management fee is linked to Envestra's regulated revenue. This implies that Envestra and OEAM would benefit from arrangements that raise this revenue and, indeed, have a joint interest in increasing regulated revenue. Revenue gains that result from increased natural gas usage, especially via increased penetration of contestable end use markets such as space heating, are appropriately encouraged by designing the contract in this manner. However, revenues could also be increased through cost allocations, transfer pricing and similar accounting changes that shift OEAM costs to Envestra. This behavior would obviously disadvantage consumers of Envestra's gas distribution services and again highlights the importance for ESCOSA to know what direct and indirect costs are being allocated to Envestra.

Envestra has argued that it would not benefit from contract arrangements that increase its regulated costs. For example, it writes that "Envestra has no financial interest in OEAM and therefore no incentive to inflate the Network Management Fee (or any other cost for that matter) to a level that is greater than that expected to recover efficient and prudent economic costs."[6] It is not clear that this is in fact the case. It is known that under cost-based regulation (such as the building block approach to CPI-X regulation), firms have incentives to misallocate costs and even engage in pure "waste" or excessive

[6] *Response to ESCOSA Draft Decision Envestra Access Arrangement,* Part B, p. 46.

expenditures that raise future revenues and thereby boost future profitability.[7] For instance, the costs of certain services provided by OEAM could be increased in the last year of an expiring AA, increasing reported cost in that year. If allowed cost changes are escalated from this base, then allowed revenues over the following AA will be greater than would otherwise be the case. Reported costs could subsequently be reallocated away from Envestra, which would be recorded as an efficiency gain that benefits both Envestra and OEAM according to the efficiency sharing provisions in the agreement. It should be emphasized that PEG has no evidence that either company has in fact behaved in this way, but it remains a theoretical concern.

It is also worth noting that submissions done on behalf of Envestra lend support to the view that ESCOSA would need to examine the costs of OEAM for it to be assured that the costs recovered through the management fee are appropriate and not, in fact, a transfer of profit. For example, the KPMG Expert Witness Statement writes

> "(a) contractor's rationale for charging prices that are sufficient to cover their direct costs plus a margin to cover their indirect costs and cost of capital is, in principle, no different to the cost model employed by ESCOSA to establish the required revenue for Envestra. This model is often referred to as the "building block" model. In both cases, the contractor and ESCOSA are attempting to ensure that the contractor and Envestra respectively recover the total cost of providing their respective services."[8]

We agree that the "required revenue" for services provided by OEAM to Envestra and Envestra's other costs can both be determined through the building block model. It is also instructive to recall that revenue requirements determined through building block methods are designed to compensate companies for both their operating costs and their capital costs (sometimes referred to as the "return on" and the "return of" capital). If a building block approach was used to determine the cost of the Envestra-OEAM contract, detailed cost information would be needed to *separate* the payments that are made for operating expenses and capital services that are provided under the contract.[9] However,

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[7] For example, see D. Sappington (1980), "Strategic Firm Behavior Under a Dynamic Regulatory Adjustment Process," *Bell Journal of Economics*, 360-372.

[8] Graham Holdaway Expert Witness Statement, p. 16.

[9] For example, if the building block approach was applied to the OEAM contract, ESCOSA would, *inter alia*, need information on OEAM's total overhead cost that was allocated to Envestra SA, the allocation of OEAM management time to Envestra SA, and the allocation of common capital (*e.g.* IT infrastructure) to Envestra SA, along with estimates of the appropriate return on (weighted average cost of

the current arrangement establishes an overall management fee linked to Envestra's regulated revenue without any support for the underlying operating or capital costs involved. Without this cost information, ESCOSA cannot evaluate whether the contract's "margin" above direct costs is in fact approximately equal to the contractor's "indirect costs and cost of capital," nor could ESCOSA examine the relative payments for indirect costs and capital.

This point is directly relevant to the concern expressed in the Draft Decision. Without information on OEAM's underlying costs, particularly the breakdown between the capital and operating costs inherent in the services provided to Envestra, ESCOSA has no basis for determining how much of the management fee compensates OEAM for its operating costs (including operational overhead) and how much is implicit compensation for the capital services provided. Accordingly, ESCOSA cannot be assured that the management fee does not effectively include some profit transfer or, equivalently, returns for Envestra's use of OEAM capital that are in excess of WACC. If profit transfers were in fact implicit in the contract, the non-capital costs of the contract must necessarily exceed the lowest sustainable cost of providing service.

We also disagree with Envestra's description of the consequences of eliminating the management fee from allowed non-capital costs. Envestra writes "(t)the application off the Commission's decision leads to perverse results. For example, is (sic) the effect of that decision that Envestra should cease to engage a contractor but rather operate its network in-house so as to ensure that all Envestra's costs meet the criteria in section 8.37…The consequence of such a step would be that Envestra would incur substantially higher costs, due to the loss of the economies of scale and specialization with contracting out."[10] This passage assumes, incorrectly, that the only two options available to Envestra are contracting out to OEAM and in-house provision.

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capital) and return of (depreciation) that capital. This information could be used to develop a "revenue requirement" for the contract which compensates OEAM for the operating and capital costs associated with its provision of network management services to Envestra. ESCOSA could then examine these data to ensure that the costs of the contract are appropriate.

[10] *Response to ESCOSA Draft Decision Envestra Access Arrangement*, Part B, p. 42.

PEG also believes that, in principle, benchmarking evidence could be used to reduce regulatory concerns about the terms of outsourcing contracts between at least partly related corporate parties. Some regulators have downplayed the value of benchmarking for this purpose because they believe it is less objective than competitive market tendering for determining whether outsourced services are priced appropriately.[11] PEG agrees that benchmarking evidence is not as direct or unambiguous as competitive market tenders in assuaging regulators' concerns about the terms of outsourced contracts to related parties. Accordingly, we believe that benchmarking studies must satisfy a very high standard to be persuasive and justify the costs of such contracts. At a minimum, satisfying this standard requires high quality data; rigorous benchmarking techniques that take account of relevant operating conditions and lead to robust benchmark evaluations; and demonstration of superior cost performance relative to a well defined and verifiable standard. As discussed, Envestra has presented benchmarking evidence by BE and WP in this proceeding. The next chapter considers this benchmarking evidence with an eye towards assessing whether it is sufficient to overcome the *a priori* concerns regarding the network management fee component of the Envestra-OEAM contract and whether it effectively demonstrates that Envestra's non-capital costs are the lowest sustainable costs needed to provide service.

[11] For example, see Essential Services Commission, *Electricity Distribution Price Review 2006-2010, Final Decision Volume 1*, pp. 174-175. The ESCV also cites Ofwat in the UK as another regulator which has examined these issues and come to a similar decision.

3. Benchmarking Envestra's Non-Capital Costs

Because of time constraints, this section will not provide a comprehensive and point by point analysis of the WP and BE benchmarking studies. Instead, this chapter will address the main points of these studies and whether they generally constitute robust benchmarking that supports the view that the Company's non-capital costs are efficient.

3.1 Definition of Benchmarked Costs

One threshold issue is whether the benchmarked cost measure should include Envestra's network development costs. Compared with other Australian gas distributors, these costs are relatively high for Envestra in South Australia. Thus if these costs are included in the analysis (as in ESCOSA's Draft Decision) Envestra's comparative performance is worse than if these costs are excluded (as in the WP and BE studies). Envestra argues that these costs reflect network specific conditions, particularly a difference in climate in South Australia that requires greater marketing effort to encourage customers to connect to the network. Hence "(t)o conclude that this factor is largely within the control of Envestra is essentially concluding that Envestra is largely in control of the climate, clearly a false premise."[12] BE agrees that gas penetration is more difficult in South Australia and requires greater marketing effort but attributes this to differences in "gas uptake." In the BE analysis, gas uptake is measured by the share of gas in a State's total energy use since "the first and most significant measure of gas penetration is the proportion of gas in the total energy demand for the state."[13]

Our assessment of this issue begins from what we believe are two indisputable facts. First, the network marketing costs themselves are subject to management discretion and, thus, controllable, although parties differ on whether and to what extent exogenous factors affect the level of these expenditures.[14] Second, network development spending is expressly designed to increase gas penetration, which in turn should improve the utilization of the existing gas distribution network and reduce unit cost.

[12] *Response to ESCOSA Draft Decision Envestra Access Arrangement*, Part A, p. 27.
[13] Benchmark Economics, *Benchmarking Non-Capital Costs*, May 2006, p. 11.
[14] Envestra appears to accept this premise in its statement "(w)hile Envestra acknowledges that it is responsible for determining its marketing program, the impetus for the program are the exogenous costs specific to its network"; *Response to ESCOSA Draft Decision Envestra Access Arrangement*, Part A, p. 27.

These hopefully non-controversial statements lead directly to the conclusion that Envestra's network marketing is purposely motivated to achieve a type of efficiency gain. Effective gas marketing will increase gas penetration. This will in turn improve the efficiency with which the existing gas delivery network is utilized. If marketing is effective, this will reduce unit cost and the overall price of gas distribution services.

From this conclusion, it also follows that there is a logical inconsistency in the argument that network costs should be excluded when evaluating efficiency. That is, Envestra and its consultants are arguing that, when evaluating the Company's efficiency, analysts must exclude expenditures that are expressly designed to improve efficiency. This paradoxical implication of Envestra's (and WP's and BE's) position seems inconsistent with the objective of benchmarking and insupportable on its face.

On closer inspection, it becomes evident that the approach favored by WP and BE can lead to distorted benchmarking assessments. It is easy to recognize that network development spending is an example of an O&M expenditure designed to achieve *capital* efficiencies (*e.g.* improved capital utilization via increased customer density on the network). In other words, network marketing can lead to a tradeoff between measured capital and non-capital efficiency. The approach of researchers attempting to assess a company's efficiency should not be to ignore expenditures that may lead to capital-O&M efficiency tradeoffs. Rather, analysts should take a more holistic approach towards assessing efficiency and be careful to consider these tradeoffs. Admittedly, this is not an easy task, but the alternative of simply eliminating expenditures associated with potential tradeoffs is not an acceptable solution since it can lead to biased efficiency evaluations. For example, suppose company A spends money on program X, which reduces its capital expenditures, but company B does not. All else equal, if a benchmarking study eliminates the expenditures of program X from its assessment of non-capital costs, company A will be measured as being more efficient than Company B in both capital and non-capital spending. However, if the effect of program X was to raise Company A's overall unit cost of service (*i.e.* even though capex declined, the operational costs of the program exceeded the effective capex savings), then eliminating these costs leads to the incorrect benchmarking conclusion: program X actually made Company A less efficient than Company B, not more.

Our analysis therefore leads us to conclude that network development costs should be included in the analysis of Envestra's non-capital costs. A failure to do so can lead to distorted efficiency assessments. It is not true, as the BE report claims, says that if network development costs are included then the "activity sets" between Envestra and other companies will not defined on a "like for like" basis. The "activity sets" for all Australian distributors include activities devoted to marketing and network development. The issue is not whether these activities are undertaken but the relative magnitude of the associated costs and the extent to which any differences in magnitudes are due to exogenous factors beyond a distributor's control. The appropriate response to this issue is for the benchmarking study to specify and examine exogenous operating conditions that may be associated with differences in the costs of the network development "activity." We turn next to the issue of appropriate operating condition variables.

3.2 Operating Conditions and Benchmark Normalizations

All benchmarking studies presented in the review of the AA accept that non-capital cost comparisons must control for differences in operating conditions across distributors. ESCOSA's analysis did this by normalizing a company's non-capital costs by the number of customers it served and km of distribution main. The WP report also reported operating cost measures normalized by customer numbers, km of distribution main, and the value of the regulatory asset base (*i.e.* opex as a percent of the regulatory asset base (RAB)).

The BE report claims that the simple metrics presented in the Draft Decision do not control adequately for operating conditions. BE presents cost models where average non-capital costs (non-capital costs per connection) are regressed against total number of connections, network size in km, gas uptake (measured as the share of gas in total state energy use), customer density (measured as connections per km), and customer class (measured as gas use per connection). All of the models use non-capital costs per customer as the dependent variable because BE claims cost drivers "can only be determined by measuring the change in average costs associated with a change in operating conditions."[15] BE says that its approach is more useful for quantifying the impact of economies of scale or economies of density on cost. The regression of unit non-capital costs versus customer density is the most important of BE's models since this is the one that is ultimately used to generate a prediction for Envestra's non-capital costs.

We agree with BE's basic concern that normalizing costs by only customers or km does not adequately control for differences in economies of scale or economies of density (although we disagree that the "only" solution to this problem is measuring changes in average cost for a given change in operating conditions; this will be discussed further in Section 3.4).[16] We also agree that customer density is an important cost driver that should be examined in a benchmarking analysis of distributors' non-capital costs. We also agree that what BE calls customer class is a relatively less important operating condition variable than customer density or controls for economies of scale.

However, we do not believe that BE's "gas uptake" variable is appropriate. Any operating condition that is used as an "independent" (or right hand side) variable in a regression model should, in fact, be independent of the model's dependent (left hand side) variable. This means that values for the independent variable should not depend on values that the dependent variable takes.

The gas uptake measure does not satisfy this criterion. Gas uptake is measured as the percent of natural gas in a State's energy use. This will be correlated with gas penetration, which depends on network marketing expenditures. As previously discussed, these expenditures should be included in the benchmarked non-capital cost measure (the left hand side variable). It follows that BE's gas uptake measure is not in fact exogenous or independent of the costs to be benchmarked. Thus while we agree that exogenous factors may affect a company's optimal marketing expenditures, the gas uptake measure presented in the BE study is not an exogenous "driver" and therefore not an appropriate operating condition to use in a benchmarking analysis.

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[15] Benchmark Economics, *op cit*, p. 8.

[16] BE does not comment on WP's benchmarking metrics, but the same criticisms would apply to the cost per customer and per km measures developed there. We also believe that WP's metric of operating cost as a percent of the RAB is not appropriate because the denominator of this expression: 1) can be distorted across distributors by differences in the valuations of the RAB and/or by the relative age of capital; and 2) the value of capital is not exogenous, and will depend on a company's capex decisions among other things.

PEG recommends an alternative measure for this operating condition known as "heating degree days." This is a well-established metric that measures the severity of winter weather and, hence, is correlated with the end-use demand for space heating. Natural gas penetration increases markedly as end-use demand for space heating increases. Heating degrees for a given day is defined as the difference between 65 degrees Fahrenheit and average temperature for that day (unless this difference is negative, in which case heating degree days is set to zero). The heating degree measure is summed for all days to arrive at annual heating degree days.

PEG estimated annual heating degree days for Australia's eight capital cities using Bureau of Meteorology data.[17] We also took a simple average of these heating degree day measures, as well as a population-weighted average of heating degree days for the eight capitals. The results are presented in Table One.

It can be seen that heating degree days for Adelaide are about 30% below those for Melbourne and about 50% lower than Canberra. However, Adelaide's heating degree days are significantly above Sydney's and far greater than those for Brisbane. Overall, Adelaide's heating degree days are about equal to the average for Australia's eight capitals and somewhat below the population-weighted average. These data show that, by Australian standards, the severity of Adelaide's winter weather is roughly the same as the eight capital average. Based on this criterion, one would expect Envestra would need to undertake greater marketing effort to connect customers than distributors serving Melbourne or Canberra but less than distributors serving the Sydney or Brisbane metropolitan areas.

PEG accepts that heating degree days is not a perfect measure of all exogenous factors that may drive differences in marketing effort.[18] Nevertheless, it represents a truly exogenous factor that can be applied in benchmarking models. Further efforts could be undertaken to refine or develop alternative measures, but it is preferable for

[17] We had only monthly data, so we calculated HDD for a month as 65 degrees Fahrenheit minus the mean of the maximum and minimum temperature for that month, multiplied by the number of days in the month.

[18] Another factor that could influence optimal marketing effort is the delivered price of gas to a distributor's "city gate." This will depend on the distance of end use markets from gas sources, among other factors. PEG was not able to locate any publicly available data on delivered gas prices to Australian city gates, but we did find some suggestions that this data is potentially available from the Australian Gas Association.

Table One

Heating Degree Days for Australia

	Population	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Annual
Adelaide	1,087,600	0	0	0	80	242	353	415	373	266	147	13	0	1,888
Sydney	4,250,100	0	0	0	0	166	291	359	295	167	35	0	0	1,313
Melbourne	3,610,800	0	0	5	175	328	455	512	462	358	261	134	13	2,704
Brisbane	1,547,700	0	0	0	0	2	137	200	155	0	0	0	0	494
Perth	1,375,200	0	0	0	0	130	237	300	286	207	113	0	0	1,274
Hobart	189,400	66	62	150	266	420	518	565	521	420	337	237	155	3,717
Canberra	327,700	0	0	44	272	507	636	713	638	472	320	150	0	3,752
Darwin	96,200	0	0	0	0	0	0	0	0	0	0	0	0	0
Simple Average	2,763,689	8	8	25	99	224	328	383	341	236	152	67	21	1,893
Population-Weighted Average		1	1	5	69	209	332	395	345	227	127	48	6	1,764

researchers to quantify exogenous factors in this manner and include these variables in benchmarking studies instead of simply eliminating nettlesome costs from the analysis.

3.3 Data

Another relevant issue in the WP and BE studies is the data used. WP and BE both rely primarily on the costs that were allowed by regulators in other access arrangements rather than the companies' actual data. Using allowed cost rather than actual cost data is very problematic in benchmarking studies.

Fundamentally, benchmarking is designed to obtain an inference on the efficiency of the management of an enterprise. Such an inference can only be obtained by examining metrics that reflect the impact of management decisions. This will not be possible using data on the costs that are *allowed* by regulators, because these metrics depend directly on decisions that are made *by regulators*. Only data that reflect the actual operations, and hence management decisions, of the companies themselves will necessarily reflect the managerial efficiency of those companies.

This issue is material, because there is an expected bias associated with the use of allowed rather than actual cost data. It is typical for utilities' actual operating costs during the term of a CPI-X plan to be less than what was allowed in the Determination. Indeed, there is a strong presumption that companies' cost performance will be below the cost "benchmarks" embodied in a CPI-X determination. Australia's incentive regulation frameworks are designed to encourage ongoing efficiencies in utility operations. If regulation is operating as intended, companies will be outperforming their cost benchmarks and their actual costs will be below allowed costs.

This implies that the WP and BE studies are likely to be biased in Envestra's favor. If actual cost data were available for other Australian companies and used for the analysis, the costs for these companies would be expected to be lower than their allowed costs. Although the amount of this bias is not known, more accurate data would be expected to reduce costs for the comparator distributors while not affecting Envestra's own reported costs (*i.e.* the company's actual costs). This would tend to increase Envestra's costs relative to the rest of the sample.

In light of these points, comparing the actual costs of one enterprise with the allowed costs of another is an example of not comparing like with like. This process is more akin to comparing, say, oranges to tangerines than the more common analogy of comparing apples to oranges. There are some obvious similarities between oranges and tangerines, but tangerines can be expected to be smaller on average. If a tangerine is compared to a group of oranges, it would be a mistake to infer that the difference in size was due to the relative efficiency or inefficiency of the tangerine grower. However, a mistake of this nature is likely when actual utility costs are compared to allowed costs.

Another data issue is the number of years used in the analysis. Both the WP and BE studies base their conclusions on sample observations for a single year while ESCOSA examines multiple years. ESCOSA's approach is preferable for a number of reasons. First, all else equal, a single year's observation is more likely to be affected by temporary or one-time factors (due to either exogenous or endogenous, management decisions) that affected either reported costs or reported business condition variables. Examples could be accounting changes or the timing of maintenance or investment cycles. In general, there will be more assurance that costs and business conditions are representative and sustainable if they use multiple years of data.

In addition, efficiency itself is a multi-year concept. One would generally expect measured efficiency to remain relatively stable from year to year and change only slowly.[19] Researchers can have more assurance that this is, in fact, the case if they examine data over a multiple year period. Efficiency measures that fluctuate wildly from year to year are likely to indicate problems with either the data used or the benchmarking model itself. For these reasons, relying on multiple years of data is useful for developing and verifying that benchmarking assessments are robust.

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[19] See Bauer, P., A. Berger, G. Ferrier, and D. Humphrey (1998), "Consistency Conditions for Regulatory Analysis of Financial Institutions: A Comparison of Frontier Efficiency Methods," *Journal of Economics and Business*, 50:85-114. The authors say relative stability in efficiency measures over time is an important criterion for assessing the degree to which a given benchmarking approach is consistent with reality or believable. One would not generally expect a company's efficiency to change substantially from year to year for reasons including the fact that managers and management practices turn over slowly and capital equipment is often adjusted gradually. These factors should produce relative stability in efficiency measures in closely related time periods.

3.4 Benchmarking Techniques and Results

The benchmarking approach of WP and ESCOSA is to construct simple, partial cost measures by normalizing non-capital costs by a limited range of operating condition variables (principally customer numbers and km of main). BE uses an econometric approach that regresses cost against a series of operating conditions. As discussed, all of BE's regression models use non-capital costs per customer as the dependent variable because of the assumption that cost drivers and controls for scale and density economies "can only be determined by measuring the change in average costs associated with a change in operating conditions."

In principle, BE's benchmarking technique is more powerful than that used by WP and ESCOSA and can yield more reliable and robust benchmarking inferences. Econometric methods can be used to consider the impact of a wide range of cost drivers on non-capital costs. Econometrics can also lead to more holistic assessments that consider how different cost driver variables interact with one another, as well as measuring both "first order" and "second order" changes associated with a given variable (*e.g.* how costs change with both the value and squared value of a given cost driver). Compared with simpler methods, the ability to consider a wide range of cost drivers simultaneously promotes more robust benchmarking assessments.

However, PEG has concerns with the actual econometric methods and results presented in the BE report. As a conceptual matter, it should first be noted that it is not true that economies of scale and density can "only" be quantified and controlled by regressing the change in a dependent variable against an operating condition (or by regressing a unit cost measure against a variable). This is, in fact, not the normal or best means of controlling for economies of scale. Economists have developed a class of "flexible form" cost functions that quantify and control for economies of scale and, depending on the choices for independent variables, economies of density. These flexible form functions also have the appealing property that they do not impose any arbitrary assumptions on the underlying technology that transforms selected operating conditions into costs. The approach taken by BE is more blunt and less flexible than the conventional econometric approach although, in practice, it does control for economies of scale in a fashion, since the concept of scale economies depends on the relationship between changes in the unit cost of service and changes in output. Some of BE's regressions embody this concept, but readers should not conclude that this is the only acceptable method for specifying cost functions.

Another concern is that BE regresses its unit cost measure against only a single variable at a time. This is unduly restrictive and cannot consider how various cost driver variables may interact. The failure to consider relevant cost driver variables in a regression can also lead to "omitted variable bias," or a biased estimate of the parameter for the variable that is in fact used in a given regression. Biased parameter estimates naturally lead to biased benchmarking predictions and are not consistent with the objective of robust benchmarking.

PEG suspects that the BE parameter estimates are characterized by omitted variable bias. Cost functions that regress a cost measure against a single variable are almost certainly too simple to capture the complexities of gas distribution technologies. We therefore believe they are unlikely to yield robust benchmarking inferences.

Another bias is likely to result from the fact that BE regresses *allowed* non-capital costs against individual business conditions. Such a regression will literally only estimate the impact of different drivers on the costs that regulators *allow*, not necessarily the costs that firms achieve. Knowing the relative impact of different variables on regulatory decisions may be interesting, but it has no necessary implications for how efficiently a firm operates after those regulatory decisions have been made. Moreover, as discussed, allowed costs are likely to be greater than actual costs, so the coefficients that result by regressing individual cost driver variables on allowed costs can be expected to be greater than those that result from regressing those same variables on actual costs. Models estimated using allowed cost data therefore have parameter estimates that can be expected to be biased in favor of positive benchmarking evaluations, when those model predictions are compared to companies' actual costs.

3.5 Standard for Evaluating Efficiency

Both the WP and BE reports conclude that Envestra's non-capital costs are efficient, but neither study provides well-defined criteria for evaluating, let alone quantifying, what would qualify as "efficient" performance. The WP report simply provides an "expected range" of values for the selected benchmarking indicators without saying what this range is based on or how it is derived. PEG assumes that the range stems from WP's judgment and collective experience, but without context or explanation (at a minimum) the reader has no basis for evaluating whether this judgment is sound.

The BE report discusses efficiency concepts in more detail. It says the concept of efficient costs is "elusive." Furthermore, BE says "(t)hough economic efficiency (productive, allocative and dynamic) is a concept widely used in regulatory economics, it is insufficiently precise to provide guidance to regulators on appropriate *levels* of efficient expenditure for regulatory purposes. It is a process not a target."[20] BE concludes that "..efficient cost is not an exact level of expenditure or target. Rather, it is one that fits within a range of the overall experience of the industry and is that appropriate to the operating scale and conditions of the business."[21]

PEG acknowledges that it is difficult to quantify or evaluate the concept of "efficiency" rigorously. We also agree that regulators should not focus on identifying a single, efficient level of expenditure and conclude that any expenditure in excess of this level is necessarily "inefficient." However, we do not believe that BE's proposed criteria provide meaningful guidance to regulators for making specific, concrete determinations on whether a utility's expenditures are efficient. Naturally, benchmarking assessments should take into account the industry's experience and the scale and operating conditions of the business but, on its own, this principle is not helpful for identifying a precise "range" of company expenditures that is consistent with efficient performance. If they are taken at face value, without further elaboration, the standards proposed by WP and BE are subjective and elastic enough to support nearly any conclusion.

PEG believes more precise standards for evaluating efficiency can be employed. Without attempting to provide a definitive resolution of this issue, we present two different "efficiency" criteria that we believe are worth considering in the current proceeding. The first is the idea of a *superior cost performer*, as established through rigorous statistical measures. The second is a *competitive market standard*.

[20] Benchmark Economics, *op cit*, p. 3.
[21] Benchmark Economics, *op cit*, p. 4.

Econometric methods can be used to determine whether a utility is a superior cost performer in a statistical sense. For example, superior cost performance can be evaluated by specifying an econometric cost model and using this model to develop both a point prediction for a company's cost and a confidence level around this point prediction. The confidence interval provides a well-defined quantification of the uncertainty associated with any given cost prediction, and the value of this confidence interval will be specific to the circumstances of any individual company and the performance of the model itself (*e.g.* all else equal, confidence intervals become smaller as the model is more successful in explaining the change in the dependent variable). If a company's actual costs are below the lower end of the (say) 95% confidence interval, then a researcher has a well-founded basis for concluding that the company's actual costs are less than what would be expected. A reasonable inference from this result is that the company is a superior cost performer. Conversely, if a company's actual costs are above the upper end of the 95% confidence interval, it is reasonable to conclude that the company is an inferior cost performer. If the company's actual costs are within the confidence interval around the point prediction, the analyst cannot reject the hypothesis that the company is an average cost performer.

This approach is attractive for a number of related reasons. First, it acknowledges that there is uncertainty associated with any benchmarking analysis. It can also quantify this uncertainty in a manner that directly reflects the conditions of the company in question. In addition, it provides the researcher with a rigorous basis for concluding with a well-defined degree of confidence whether the enterprise in question is or is not efficient.

The BE report did provide a confidence interval around its value for predicted cost. However, as discussed, PEG has serious concerns with this model and the predictions it generates. Accordingly, we do not believe that it can be used to make robust inferences on efficiency.

The second option is the competitive market standard. It is known that competitive markets create strong incentives to perform efficiently. Accordingly, if a utility can show that its efficiency is compatible with what would be expected in a competitive market, regulators would have more assurance that the company's costs were efficient.

PEG believes it is possible to operationalize this standard by considering the relationship between the average and the frontier levels of efficiency in the utility industry, and comparing this to the relationship between average and frontier efficiency levels in competitive markets. One would expect that, over time, competitive markets drive the industry's average level of efficiency to be "close" to but not actually at the frontier performance. Not all firms in competitive markets will be operating at frontier standards; indeed, in competitive markets, firms that are on the frontier tend to earn above average returns, whereas average firms in the industry earn only average returns (*i.e.* returns approximating their cost of capital). The competitive market experience implies that it is not reasonable for regulators to assume that all firms in a *utility* industry should be operating on the frontier, because if competitive markets actually behaved in this way then only firms on the frontier could earn returns commensurate with their cost of capital and all other firms would have returns below their cost of capital.

It follows that, in competitive markets, firms that are earning returns commensurate with their cost of capital have efficiency levels that are "close" to but below frontier levels. The critical issue for operationalizing this standard for utility regulation is how "close" this relationship is. PEG provides some information on this point by reviewing a number of benchmarking studies in competitive industries. We surveyed published frontier benchmarking studies in two competitive sectors: banking and farming. Tables Two and Three summarize our findings from the two surveys.

The surveys show that, on average, efficiency levels of firms in these two competitive sectors are about 80-90% of frontier efficiency levels. Our survey on banking efficiency using frontier methods covers Greek, Turkish, European and U.S. banks. The studies for European banks report average efficiency levels from 70% to 85% using parametric methods. The average efficiency level among U.S. banks is from 80% to 90% using this same approach. Non-parametric approaches like data envelope analysis (DEA) show average efficiency levels to be even lower in this competitive industry. The efficiency studies in the farming sector find average efficiency levels in a similar range. It is clear from this survey that the average efficiency level of firms is not

Table Two
Survey of Efficiency Studies of Banking Firms

Study	Data Coverage	Method	Result
Bauer, Berger, Ferrier and Humphrey (1997)	US Banks 1977-1988	Parametric	Average cost efficiency = 83%
		Nonparametric	Average cost efficiency = 30%
Berger and Humphrey (1997)	Survey of 130 efficiency studies of financial institutions	Parametric	Average efficiency = 84%
		Nonparametric	Average efficiency = 72%
Berger and Mester (1997)	US Banks 1990-1995	Parametric	Average cost efficiency = 86.8%
Casu and Girardone (2002)	European Banks 1993-1997	Parametric	Average economic efficiency = 86%
		Nonparametric	Average technical efficiency = 65%
Christopoulous and Tsionas (2001)	Greek Banks 1993-1997	Parametric	Average economic efficiency = 65%
Christopoulous, Lolos and Tsionas (2002)	Greek Banks 1993-1998	Parametric	Range of economic efficiency = 60% -100%
Clark and Siems (2002)	US Banks 1993-1997	Parametric Method 1	Average cost efficiency = 86%
		Parametric Method 2	Average cost efficiency = 74%
Eisenbeis, Ferrier and Kwan (1999)	US Banks 1986-1991	Parametric	Range of average efficiency level by size =
		Nonparametric	Range of average efficiency level by size =
Fethi, Jackson and Weyman-Jones (2002)	Turkish Banks 1992-1999	Nonparametric (one variant)	Average technical efficiency = 57%
Vennet (2000)	Turkish Banks 1995-1996	Parametric	Average cost efficiency = 80%

Table Three
Survey of Efficiency Studies of Farming Firms

Study	Data Coverage	Method	Result
Brummer, Glauben and Thijssen (2002)	German, Dutch and Polish Diary Farms 1991-1994	Parametric	Range of average technical efficiency by country = 76% - 95%
Hadri, Guermat and Whittaker (2003)	English Cereal Farms 1982-1987	Parametric	Average technical efficiency = 86%
Kumbhakar (2001)	Norwegian Salmon Farms 1988-1992	Parametric	Range of average technical efficiency by specification = 79% - 83%
Kumbhakar, Ghosh and McGuckin (1991)	US Diary Farms 1985	Parametric	Range of technical efficiency by size = 66.8% - 77.4%
			Range of average allocative efficiency by size = 84.6% - 87.6%

at frontier performance in either of these two competitive sectors. Average efficiency levels in competitive industries are about 10% to 20% below the performance frontier.

It should be emphasized that neither the WP nor the BE studies have employed this approach. Both reports appear to compare Envestra to the mean level of performance in Australia's gas distribution industry. They also appear to conclude that if actual cost is equal to average (*i.e.* expected) cost, then the company in question is efficient. PEG does not believe that such a showing is sufficient for demonstrating efficiency, nor is it compatible with the competitive market standard proposed here. The latter standard examines a relationship between frontier and average performance levels, not average efficiency in isolation.

3.6 Cost Sustainability

The BE report also considers the issue of cost "sustainability" and concludes that "as actual costs amounted to only 87 per cent of estimated costs, we are of the view that this efficient cost performance may not be sustainable over the long run."[22] PEG believes that no conclusion can be derived on cost sustainability from the BE study and, in general, it will be very difficult to derive any conclusion on this issue from a study that examines a single year of data. Cost "sustainability" necessarily involves a consideration of whether expenditures can be maintained on a multi-year period while still providing service at what regulators (and the public) believe are appropriate quality levels. This inherently multi-year concept cannot be evaluated from a single cross examination. At best, one cross section can provide information on what factors drive cost differences across firms at a given point in time, not whether costs are compatible with exogenous drivers over a multi-year period.

It should also be recognized that, in any given year, costs may not be "sustainable" because they are either too low *or* too high. Discussion of this concept appears to contemplate only the first possibility. But any given cost observation could in principle reflect the effect of actions taken in that year which increase costs but which are not undertaken (at least to the same degree) year in and year out. For example, utilities

[22] Benchmark Economics, *op cit*, p. ii.

typically have investment or maintenance "cycles" that take place over a multi-year period, and the amount of investment or maintenance activity undertaken in a given year may depend on where they happen to be in the cycle. Costs could therefore be unsustainably high if they reflect, *inter alia*, an unusually large amount of investment or maintenance activities. Since the issue of cost sustainability is part of the Gas Code, it is important not to lose sight of this basic point.

PEG believes the competitive market paradigm presented in the previous section could be useful for determining whether non-capital costs reflect the lowest sustainable cost, as required by the Gas Code. It is reasonable to believe that the costs that set the price in a competitive market will correspond with the lowest sustainable cost. The competitive market paradigm and experience from competitive markets suggests that these costs would be consistent with efficiency levels that are 10%-20% below the frontier levels of efficiency in the industry. This information could in principle be used to define a well-defined range for "lowest sustainable costs" that is tailored to the business conditions of an individual company.

3.7 Operating-Capital Cost Allocations

BE presents a regression of capital expenditures (capex) per customer against customer density. The report finds a similar trend line to the analogous regression for non-capital costs. It therefore concludes that "there is no reason to believe that allocation policies have resulted in lower Non Capital costs at the expense of higher capex."[23]

The capex econometric model presented in the BE report simply has no bearing on the issue of operating versus capital cost allocations. Fundamentally, this is an issue of accounting and not econometric cost drivers. An econometric model cannot distinguish whether the selected dependent variable does or does not contain the correct cost components. In fact, if the opex and capex models had identical cost drivers, an analyst could reallocate costs from one cost category to another without influencing the regression results that are obtained. However, these cost reallocations would necessarily influence the conclusion about whether the company in question was "efficient" since

[23] Benchmark Economics, *op cit*, p. 19.

they by definition impact the value of cost measure that is subject to benchmarking. PEG believes there is no evidence one way or the other on whether Envestra's opex costs are in fact defined appropriately because an econometric cost model is not the appropriate tool for addressing this issue.

4. Conclusions

Given the available evidence, we believe ESCOSA's decision to require removal of the network management fee when determining allowed costs for Envestra is sound. This network management fee raises legitimate regulatory concerns which could conflict with ESCOSA's statutory requirements. In principle, performance benchmarking could assuage these concerns. Any such benchmarking study would have to use high quality and appropriate data; control simultaneously for the impact of major cost driver variables on gas distributors' non-capital costs; employ benchmarking techniques that lead to unbiased estimates of the impact of cost drivers on distributors' costs and, by extension, unbiased benchmarking evaluations; and present rigorous quantitative evidence on the imprecision associated with benchmarking predictions.

The benchmarking studies presented by WP or BE do not satisfy these criteria. These studies are problematic with respect to the data chosen, the definition of non-capital costs that excludes network marketing expenditures, the benchmarking techniques employed, the selected operating condition variables, and the standards used to evaluate efficiency. Overall, the benchmarking studies presented on behalf of Envestra in this proceeding do not provide persuasive evidence that Envestra's non-capital costs inclusive of the network management fee deliver the lowest sustainable cost of providing service.

Although PEG has not had time to investigate the issue in depth, we believe that such benchmarking evidence could have provided in this proceeding. We recognize that one issue that has likely shaped the benchmarking approaches adopted by BE and WP is the paucity of data in Australia (*e.g.* on actual cost). However, even restricting the analysis to Australian data, researchers can use bootstrapping and similar methods to develop more robust benchmarking evaluations.

More fundamentally, there is no reason to restrict the benchmarking analysis to Australian companies. This is especially true for non-capital cost benchmarking, since high quality data on overseas gas distributors' non-capital costs and cost driver variables are readily available. The more ample datasets that are available overseas would have allowed more rigorous benchmarking methods to be employed and promoted more robust benchmarking evaluations. It is true that international benchmarking does introduce its own challenges, but this is not a sufficient reason for not exploring this option, especially if, by restricting their attention to Australian data, analysts find themselves undertaking inherently flawed comparisons of the actual costs of one company to the allowed costs of others.

PEG also believes the competitive market paradigm presented in this report could be useful for future AA proceedings. In the absence of market testing, an application of this paradigm could be used by companies to demonstrate that their non-capital costs reflect the lowest sustainable cost, as required by the Gas Code. It is reasonable to believe that the costs that set the price in a competitive market will be consistent with the lowest sustainable cost. Experience from competitive markets suggests that these costs would be consistent with efficiency levels that are 10%-20% below the frontier levels of efficiency in the industry. This information, combined with rigorous benchmarking studies, could be used to define a well-defined range for "lowest sustainable costs" that is tailored to the business conditions of an individual company.

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ESSENTIAL SERVICES COMMISSION APPEAL PANEL

Reference: E3/2008

APPLICANT:	Multinet Gas (DB No. 1) Pty Ltd and Multinet Gas (DB No. 2) Pty Ltd (trading as Multinet Gas Distribution Partnership
RESPONDENT:	Essential Services Commission
BEFORE:	Essential Services Commission Appeal Panel
DATE OF HEARING:	8-12 September, 6 & 8 October 2008
DATE OF DECISION:	11 November 2008

THE APPEAL PANEL ORDERS:

1. Cost of Capital and Taxation

   This Ground of Review is dismissed

2. Operating Expenditure – Rate of Change

   This Ground of Review is dismissed

Roderick Smith
Chairman
On behalf of the Panel

I CERTIFY THIS TO BE A TRUE COPY OF THE DECISION MADE BY THE APPEAL PANEL IN THIS PROCEEDING ESC REGULATIONS REG. 21

RICHARD O'KEEFE

ESSENTIAL SERVICES COMMISSION APPEAL PANEL

ESSENTIAL SERVICES COMMISSION APPEAL PANEL

ESSENTIAL SERVICES COMMISSION APPEAL PANEL

APPEARANCES:

Multinet Gas (DB No. 1) Pty Ltd and Multinet Gas (DB No. 2) Pty Ltd (trading as Multinet Gas Distribution Partnership	Mr A C Archibald QC Mr W Houghton QC Mr S R Horgan, of Counsel Mr D Farrands, of Counsel Instructed by Johnson Winter and Slattery Lawyers
Essential Services Commission	Mr N J Young QC Mr S Scerri QC Mr M Borsky, of Counsel Mr P Gray, of Counsel Instructed by Gilbert & Tobin Lawyers

REASONS FOR DECISION OF APPEAL PANEL

1. This application for review by Multinet Gas (DB No.1) Pty Ltd and Multinet Gas (DB No.2) Pty Ltd (trading as the Multinet Gas Distribution Partnership) ("the Applicant") is brought under Section 39(1) of Schedule 1 of the Gas Pipelines Access (Victoria) Law ("the Law") against a Final Decision published on 7 March 2008 and Further Final Decision published on 19 May 2008 of the Essential Services Commission ("the Commission").

2. Both the Applicant and the Commission were represented by counsel on the hearing of the application for review.

3. At a directions hearing convened by the Panel a preliminary hearing was requested by the Parties to deal with the question of what, under the Law, constituted a reviewable decision of the Commission. This preliminary hearing was later abandoned by the Parties who agreed that the issue was instead better dealt with during the substantive hearing.

Nature of the Review

4. The application for review relates to the decision of the Commission, under Section 2.42 of the National Third Party Access Code for Natural Gas Pipeline Systems ("the

Code"), to approve its own access arrangement or revisions to an access arrangement in place to the access arrangement or revisions to an access arrangement submitted by the Applicant.

5. The matter which had been the subject of the abandoned preliminary hearing was not raised as a substantive issue. The parties proceeded on the basis that no technical objection should be raised as to the framing of the Application for Review.

6. In the view of the Panel, the Code intends that a decision by a regulator not to approve a service provider's proposed access arrangement or revisions and the reasoning behind this non-approval forms an essential part of the decision to consequently draft and approve its own access arrangement or revisions in the context of Section 2.42 of the Code.

7. The process for submission and consideration of an access arrangement or revisions to an access arrangement is dealt with in detail in Section 2 of the Code and involves a number of steps the nature and effect of which was a subject of debate during the hearing.

8. The review is expressed in the Law as a limited review and, under Section 39 (5), restrictions are imposed on the Panel in relation to the material which may be considered on the review.

9. The sole statutory grounds under which an application for review may be made are set out in Section 39 (2) require the establishment by an applicant:

   (a) of an error of fact in the relevant regulator's finding of facts; and/or

   (b) that the exercise of the relevant regulator's discretion was incorrect or unreasonable having regard to all the circumstances; and/or

   (c) that the occasion for exercising the discretion did not arise.

10. Again, in seeking to establish such grounds, an applicant may not raise any matter which was not raised in submissions to the relevant regulator before the relevant decision was made.

11. The Panel received extensive submissions by both parties as to the nature of the review and the role to be adopted by the Panel in considering the grounds of review. A number of authorities in relation to appeals from administrative decisions were relied upon by the parties in support of their contentions in this respect. The Panel has considered the submissions and these authorities.

Review Ground 1 - Cost of Capital and Taxation

Introduction

12. Section 8.31 of the Code permits gas distributors to make a choice of methodologies, including the Capital Asset Pricing Model ("CAPM"), as the basis for calculating the Rate of Return and by extension, requires the ESC to accept that choice. The Applicant elected to use CAPM.

13. CAPM contains a number of elements: the risk free rate of return, the market rate of return and the equity beta. The gas distributors and the Commission agreed on appropriate measures of and levels for both the risk free rate of return and the market rate of return. The Commission did not accept the Applicant's proposal for an equity beta of 1.0.

14. Another element to be taken into account in determining the rate of return is the cost of taxation. This brings into account the impact of imputation credits which are measured by a value described as gamma. The Commission did not accept the Applicant's value for gamma of 0.35.

15. The Applicant alleges that the Commission, in rejecting the Applicant's proposed equity beta of 1.0 and gamma of 0.35:

(a) made errors of fact; and/or

(b) exercised its discretion incorrectly or unreasonably in all the circumstances; and/or

(c) the occasion to exercise its discretion did not arise

within the meaning of Section 39 (2) of Schedule 1 of the Law.

16. Specifically, the Applicant contended that both its proposed equity beta of 1.0 and its proposed gamma of 0.35 fell within a reasonable range having regard to a number of factors required by or arising from the Code. The Applicant further contended that, because its proposals fell within that range of choices reasonably open to it and was consistent with reference tariff principles, the occasion for the Commission to exercise a discretion under the Code to reject the Applicant's proposals and substitute its own did not arise.

17. In its argument that no occasion for exercise of discretion arose it relied substantially upon what it argued was the "Gasnet" principle.

<u>Occasion for Exercise of Discretion – Application of "Gasnet" Principle</u>

18. This primary argument of the Applicant flowed from Section 39 (2) (iii) and was based upon various recent authorities including, in particular, Application by Gasnet Operations Pty Ltd (2004) ATPR 41-978, a decision of the Australian Competition Tribunal ("the Tribunal"). This decision has since been referred to in the Federal Court decision, ACCC v ACT (2006) 152 FCR 83.

19. In his oral submissions senior counsel for the Applicant argued:

> "The reason why here the regulator was not entitled to withhold approval of the distributors' proposed revisions was that ------ the Gasnet principles were not satisfied"

20. The Applicant argued that the revisions to access arrangement in relation to both equity beta and gamma submitted by it to the Commission complied with the Code and that the power of the Commission to reject the revisions and to draft and approve

its own access arrangement could not have arisen unless and until the Commission determined that the Applicant's access arrangement did not so comply. It contended that the Commission had not and should not have reached that threshold point.

21. The Applicant's complaint was, in effect, that the Commission went straight to determining the values it preferred as satisfying the Code principles without first asking itself whether the values submitted by the Applicant did so.

22. In referring to the Gasnet decision the Applicant placed substantive reliance upon the following passage from the judgment, which referred to an earlier Supreme Court of Western Australia judgment in Re Michael Ex Party Epic Energy (WA) Nominees Pty Ltd (2002) 25 WAR 511:

> "-----there is no single correct figure involved in determining the values of the parameters to be applied in developing an applicable Reference Tariff. The application of the Reference Tariff Principles involves issues of judgment and degree. Different minds, acting reasonably, can be expected to make different choices within a range of possible choices which nonetheless remain consistent with the Reference Tariff. Where the Reference Tariff Principles produce tension, the Relevant Regulator has an overriding discretion to resolve the tensions in a way which best reflects the statutory objectives of the Law. However, where there are no conflicts or tensions in the application of the Reference Tariff Principles, and where the AA [*Access Arrangement*] proposed by the Service Provider falls within the range of choice reasonably open and consistent with Reference Tariff Principles, it is beyond the power of the Relevant Regulator not to approve the proposed AA simply because it prefers a different AA which it believes would better achieve the Relevant Regulator's understanding of the statutory objective of the Law." (Italics added).

23. The Applicant contended that, in the decision here under review, as in the relevant part of the Gasnet decision, there are no such conflicts or tensions in play, and that accordingly, the rationale expressed in the above paragraph applied.

24. It was further contended by the Applicant that, on it submitting revisions which were within the reasonable range of choices consistent with the Code, the Commission was constrained in exercising any discretion in relation to the proposed access arrangement, even such as may be required to balance the interests identified in Section 8.1 of the Code. The Applicant submitted that it is only when the value of a parameter in a proposed revision is not within a reasonable range for that parameter that the regulator may then proceed to substitute its own judgment or assessment.

25. The argument of the Applicant was therefore partly in relation to the substantive issue of exercise of discretion and partly in relation to the process adopted by the Commission in not first making a specific determination whether the proposed parameter values satisfied the Code.

26. The Commission, in response, contended that, as regulator, it was obliged by Section 2.46 of the Code to approve proposed revisions only if **positively** satisfied that the proposed access arrangement, as revised, would contain the elements and satisfy the principles set out in Sections 3.1 to 3.20. In doing this, it argued, it was obliged to take into account the factors described in Section 2.24.

27. Section 2.24 sets out the following requirements:

> "The Relevant Regulator may approve a proposed Access Arrangement only if it is satisfied the proposed Access Arrangement contains the elements and satisfies the principles set out in sections 3.1 to 3.20 [of the Code]. The Relevant Regulator must not refuse to approve a proposed Access Arrangement solely for the reason that the proposed Access Arrangement does not address a matter that sections 3.1 to 3.20 do not require an Access Arrangement to address. In assessing a proposed Access Arrangement, the Relevant Regulator must take the following into account:
>
> (a) the Service Provider's legitimate business interests and investment in the Covered Pipeline;
>
> (b) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline;

(c) the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline;

(d) the economically efficient operation of the Covered Pipeline;

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(f) the interests of Users and Prospective Users;

(g) any other matters that the Relevant Regulator considers are relevant."

28. The Commission also submitted that the process of taking into account the Section 2.24 factors is necessarily evaluative and requires the exercise of judgment as these principles tend in differing directions and lead to the need for a balancing exercise. It argued that the objectives set out in Section 8.1 are also relevant and require the exercise of discretion. It stated that the exercise of this discretion in relation to competing factors is critical to a regulator deciding whether it can be positively satisfied of the matters referred to in Section 2.46.

29. Senior counsel for the Commission contended that the determination of values for both beta and gamma involved forecasts and that Section 8.2 of the Code requires that the Commission be satisfied that such forecasts represent best estimates on a reasonable basis, a matter also requiring the exercise of discretion by the Commission.

30. To the extent that the Applicant's submission relates to process it is clear that this itself does not give rise to review under Section 39 (2) of Schedule 1 of the Law unless it is accompanied by one of the specific elements identified in sub-sections (i) to (iii) of that provision.

31. The Gasnet decision dealt with two parameters used in calculating the Reference Tariff, an inflation forecast and the risk free rate of return used in the CAPM calculation. The Tribunal held in that case that the rejection by the ACCC, the regulator, of sculpted inflation forecasts proposed by Gasnet was a correct exercise of its discretion and was reasonable even though it noted that, "there is no one correct

method of estimating inflation." However it noted that the ACCC in that case had sought to alter the CAPM methodology selected by Gasnet by using two different measures of the risk free rate of return (a ten year bond rate and a five year bond rate) in a single equation. The Tribunal found that:

> "The ACCC erred in concluding that it was open to it to apply the CAPM in other than the conventional way to produce an outcome which it believed better achieved the objectives of s 8.1. In truth and reality, the use of different values for a risk free rate in the working out of a Rate of Return by the CAPM formula is neither true to the formula nor a conventional use of the CAPM. It is the use of another model based on the CAPM..." [para 47].
>
> (underlining added)

32. The Tribunal also made clear in the Gasnet decision that, where the reference tariff principles in the Code produce tensions, a regulator has an overriding discretion to resolve these tensions in a way which best reflects the statutory objectives. The Tribunal took the view that the particular issue under consideration, the application by the Regulator of CAPM, was not one which produced such tensions and, therefore, not one where the regulator had occasion to exercise such discretion.

33. In the Gasnet decision the Tribunal cited a paragraph from the judgment of Mr Justice Parker in Re Michael which discussed the issue of resolving tensions under the Code. His Honour had clearly expressed the view, in effect, that the intention of the Act and the Code is that it is the task of the regulator to resolve any potential conflicts which usually lie between the commercial interests of the service provider and the cost interests of users or consumers (and also the public interest).

34. The failure by the regulator in Gasnet to properly apply the CAPM methodology legitimately selected by the distributor is a quite different situation to that which exists in this application where it is not contended that there has been any misapplication by the Commission of the basic CAPM methodology but rather there is disagreement in relation to what is, effectively, the choice of inputs.

35. It is noteworthy, also, that, in Gasnet, another head of claim related to the proposal by the service provider of sculpted forecasts, an issue which the Panel considers is more closely aligned with that in the decision under review. In relation to that issue the Tribunal found that the regulator was entitled to and correctly exercised its discretion to reject the service provider's proposals and substitute its own.

36. It is therefore the view of the Panel that Gasnet should be construed, within the confines of its facts, to apply to a situation where a regulator departs from a methodology, which is within the entitlement of a distributor to select, in circumstances where conflicts or tensions are not produced. On the contrary, in the decision under review, the Panel considers that there are conflicts arising in relation to the choice of expert opinion as to the appropriate values for both equity beta and gamma. These conflicts centre on the application of the Section 2.24 factors and must fall to the regulator to resolve by exercising its discretion.

37. The choice between varying expert opinions relates to forecasts and squarely raises the need for the regulator satisfy itself as to a best estimate on reasonable grounds.

38. To view the effect of Gasnet otherwise would, in the opinion of the Panel, be to remove from a regulator a discretion to balance competing interests which is fundamental to the Code.

39. Accordingly, the Panel does not accept the Applicant's argument under Section 39 (2) (iii) that the occasion for the Commission to exercise its discretion in relation to the value of equity beta and gamma did not arise.

40. This leaves for the Panel to consider whether the Commission, either, under Section 39 (2) (i), made an error of fact, or, under Section 39 (2) (ii), exercised its discretion wrongly or unreasonably in rejecting the Applicant's values for equity beta or gamma and selecting its own values.

Error of Fact or Incorrect Exercise of Discretion – Equity Beta

41. As previously noted, as the Applicant had selected the CAPM methodology in accordance with Section 8.31 of the Code, the Commission was bound to accept this methodology. As also noted, in relation to CAPM, it is only equity beta that is the subject of dispute.

42. Equity beta is a mechanism for adjusting the diversified market risk premium over the risk free rate of return for particular asset classes. This involves an assessment of the element of risk. An equity beta of 1.0 yields the market risk premium, or neutral risk, whilst an equity beta of more than 1.0 reflects higher risk and an equity beta of less than 1.0 reflects lower risk.

43. In its proposed access arrangement the Applicant selected an equity beta of 1.0 being the market average. The Commission rejected this and, in its substituted access arrangement, selected an equity beta of 0.7, which it then effectively adjusted to 0.8 by making a transitional allowance. The effect of the Final Decision, therefore, was to determine that the equity beta for the third regulatory period should be fixed at 0.8.

44. In its written and oral submissions the Applicant raised the following allegations of error or, alternatively, incorrect exercise of discretion on the part of the Commission:

(a) that the principle of regulatory precedent and the need for regulatory consistency and stability required that the Commission accept the Applicant's proposal of a value for equity beta of 1.0;

(b) that the overwhelming weight of expert opinion indicated a value for equity beta of 1.0 or more;

(c) that, if the value of equity beta is to be set at a level away from 1.0, the Commission, in applying the Sharpe CAPM model, should have utilised the refinements to that model introduced by Merton and/or Black; and

(d) that, if the value of equity beta is to be set at a level lower than 1.0, the Blume adjustment should have been applied.

45. Senior counsel for the Applicant referred to a number of recent regulatory decisions under the Code relating both to gas and electricity most of which, he argued, resulted in equity beta being set at a value of 1.0 or more. He relied upon the principle of regulatory precedent and stressed the commercial and practical importance of stability and certainty in regulatory decision making.

46. In response, senior counsel for the Commission argued that the weight to be given to regulatory precedent or regulatory consistency, which he submitted is a factor but not a binding factor, must be balanced against the need to address prevailing conditions. He contended that the Commission had taken these matters into account and given them appropriate weight.

47. The important issue of the expert opinion obtained by the parties was the subject of lengthy submissions. The Applicant relied upon reports and other material provided by KPMG, Professors Gray and Officer, Competition Economics Consulting Group, NERA Economic Consulting and Professor Lally. It also heavily criticised the report obtained by the Commission from Allen Consulting Group as providing raw data without a firm conclusion.

48. The Commission countered by arguing that the volume of expert opinion covered a wide range of values, that the Commission had taken all this material into account and that it was entitled ultimately to accept the Allen Consulting Group report as providing a range of values for beta from which it had reasonably derived the value fixed in the Final Decision.

49. In relation to regulatory precedent or regulatory consistency the Panel accepts the contention of the Commission that, whilst these concepts are appropriately to be taken into account by a regulator, they will not themselves be decisive if there are other countervailing issues which are of greater weight. In this regard, the proper application of the provisions of the Code to the prevailing conditions must be of more significance.

50. In this context the Commission, whilst taking the issues of precedent and consistency into account, has reasonably placed more weight on its view of prevailing conditions

and the volume of expert opinion available in order to arrive at a best estimate on a reasonable basis.

51. In arriving at a best estimate on a reasonable basis in accordance with the Code the Panel considers that the Commission was entitled to place reliance on the Allen Consulting Group material. Ultimately it has chosen a value for equity beta at the upper end of the range estimated by ACG and at the lower end of some of the expert opinions obtained by the Applicant.

52. Whilst there is clearly a divergence of expert opinion, with experts of substantial reputation on differing sides of the fence, the Panel considers, nevertheless, that it was reasonably open to the Commission, in seeking to resolve the tensions between the (Code) Section 8.1 factors, to determine that a value of 0.8 represented a best estimate on a reasonable basis having regard to the opinion available.

53. The next submission made by the Applicant was that, if, contrary to the view contended for by the Applicant, equity beta was to be set at a level lower than 1.0, there was evidence that the CAPM model, initially devised by Sharpe, would produce a downward bias. In an attempt to address this tendency, two refinements to the model had been devised by, respectively, Black and Merton. The Applicant maintained that, in its Final Decision, the Commission had wrongly declined to implement either of these refinements and allowed the CAPM model to be applied in its original form.

54. The assumption on which the Black refinement is based is that equity investors will normally borrow at a rate above the long term bond rate assumed within the Sharpe model. The Merton refinement extends the Sharpe model over multiple investment periods assuming different investment returns. The Applicant contended that the Commission erred in rejecting either of these refinements.

55. In response, the Commission argued that, on the basis of a report from Allen Consulting Group, there was doubt about the soundness of the contention of under estimation in the Sharpe model and that it was entitled, on this evidence, to apply the Sharpe model without adjustment. It also submitted that the unadjusted Sharpe model

remains the conventional and usual method of assessing CAPM and that it was entirely proper for it to rely on this model.

56. Whilst there are arguments in favour of either approach in differing circumstances the Panel is not satisfied that the approach adopted by the Commission constituted an error or incorrect exercise of discretion on its part. There was sufficient evidence in support of the original Sharpe model to enable the Commission to reasonably apply that model without refinement.

57. The final matter raised by the Applicant concerned the Blume adjustment. This statistical adjustment deals with estimation errors in empirical data on the assumption that beta values tend to regress to one over time. The Applicant relied on the fact that commercial providers of beta estimates, such as Bloomberg, apply the Blume adjustment to account for such mean reversion. It also cited expert evidence supporting the utilisation of Blume.

58. The Commission again pointed to the diversity of expert opinion on this issue in contending that there was no reviewable error on its part in rejecting the Blume adjustment. In support of the view it eventually took, it referred to the Allen Consulting Group report which recommended not applying Blume.

59. It is clear that the various experts express a range of views as to the desirability of applying Blume and the circumstances in which it might or might not be applied. Having considered this range of opinion the Panel is satisfied, as was the case with the Sharpe CAPM, that it was reasonably open to the Commission, in exercising its discretion under the Code, to accept and act on the expert advice that it had obtained to reject the application of Blume.

60. It is therefore the view of the Panel that there has been no error of fact on the part of the Commission nor any wrong or unreasonable exercise of discretion in adopting a value of 0.8 for beta in its assessment of rate of change for the next regulatory period.

<u>Error of Fact or Incorrect Exercise of Discretion – Gamma</u>

61. A consideration of the revenue required by regulated utilities requires that an allowance be made for expected taxation liabilities. These liabilities are reduced by dividend imputation, which allows Australian resident shareholders to claim a credit for corporate taxation already paid. Accordingly, regulatory decisions take dividend imputation into account when assessing taxation liability.

62. Imputation tax credits attach to dividends and so are distributed to shareholders via the distribution of dividends. The value of imputation credits (denoted by gamma, γ) is the product of the proportion of credits that can be distributed (the distribution rate, denoted by F) and the value of imputation taxation credits claimed as a proportion of their face value (the utilisation rate, denoted by theta, θ). Expressed arithmetically: $\gamma = \theta \times F$.

63. The Applicant's proposal of a gamma value of 0.35 was not accepted by the Commission, which instead applied a value of 0.5. The Applicant submitted that the adoption by the Commission of a gamma of 0.5 involved either an error of fact or an incorrect or unreasonable exercise of the Commission's discretion.

64. The Applicant submitted that two empirical studies by Associate Professor Hathaway and Professor Officer showed that the value of gamma had declined since the last regulatory decision was made in 2002, when gamma was set at 0.5. The first study by Hathaway and Officer (covering the period 1984 to 1996) found that the distribution rate for all companies, Australia-wide, was 0.8 and that the utilisation rate was 0.6, yielding gamma of 0.48. Their more recent study (covering the period 1988 to 2002) found that the Australia-wide average gamma for all companies was 0.355, based on an average distribution rate of 0.71 and an average utilisation rate of 0.5. The study covered a period affected by two changes to dividend imputation rules: the introduction of the 45 day rule in 1997 (under which eligibility for an imputation credit requires that a share be held for 45 days around the ex-dividend date); and the availability from 2000 of cash refunds for imputation credits in excess of tax paid.

65. The Applicant also relied on two studies produced by SFG Consulting in 2007, which the Applicant contended confirmed an implied value for gamma of 0.16 to 0.32, adopting a distribution rate of 80%.

66. The Commission divided its consideration of the value of gamma proposed by the gas distributors into the two constituent parameters of gamma, the distribution rate (F) and the utilisation rate (theta).

67. In its Final Decision, the Commission reiterated the view expressed in its Draft Decision that gas distributors have the capacity to pay out dividends sufficient to distribute all imputation credits to their shareholders, which is consistent with F equal to 1.0.

68. The Commission also relied upon a study undertaken by Allen Consulting Group which found that a benchmark utility would have an incentive to distribute all of its franking credits over time and argued that that the Applicant had not refuted this finding by providing evidence of its actual distribution rate. The Commission contended that the Applicant failed to show any error in the application of a distribution rate of 1.0.

69. There was disagreement between the Commission and the Applicant as to whether Hathaway and Officer's overall estimate of a distribution rate of 0.71 is also the best estimate for gas distribution firms. Hathaway and Officer provide little guidance in this area, but note that their results are "Australia-wide **average** results and market sectors or individual companies may experience substantial variations from the average." [Neville Hathaway & Bob Officer, The Value of Imputation Tax Credits Update 2004, November 2004, p.8]

70. The Panel notes that the distribution rate of 0.71 by definition relates to a range of companies, including those with substantial growth options and relatively low dividend distribution rates. Companies with fewer growth options require relatively high distribution rates in order to attract and retain shareholders.

71. The Commission's conclusion that gas distribution companies fall into the latter category and that a benchmark utility is likely to have a distribution rate of 1.0 is supported by the available facts. A value of 1.0 for the distribution rate also has a regulatory precedent, as noted in the decision Envestra Limited v Essential Services Commission of South Australia [No 2] (2007) SADC 90 at para 105.

72. On the material available the Panel considers that it was reasonably open to the Commission to conclude that, under Section 8.2 of the Code, the best estimate on a reasonable basis of the value for distribution rate (F) was 1.0. Accordingly, the Panel finds that there is no error of fact or incorrect exercise of discretion in the Commission's conclusion to that effect.

73. The Commission considered a range of empirical studies relating to the utilisation rate (the value of theta). It submitted that the results of studies based on the period since the most recent relevant tax change (the ability from 2000 to claim a tax refund for imputation credits in excess of tax paid) and focusing on data for large firms yield estimates for theta ranging from 0.41 to 0.72. The rationale for focussing on large firms was said to derive from statements by Hathaway and Officer that data relating to these firms is more reliable.

74. The Applicant's proposal for a point value of gamma of 0.35, if based on a distribution rate of 0.71 implies a value for theta of 0.49, which is well within the 0.41 to 0.72 range considered to be the most reliable. The point value of theta equal to 0.5 applied by the Commission is also well within this range and, in addition, is not materially different from the value proposed by the Applicant.

75. Accordingly, again, the Panel considers that it was reasonably open to the Commission, on the material available, to arrive at an estimate of theta equal to 0.5 as a best estimate arrived at on a reasonable basis in accordance with Section 8.2 of the Code. There is, therefore, in the opinion of the Panel, no error of fact or incorrect exercise of discretion on the part of the Commission in ultimately applying a value for gamma of 0.5.

76. Accordingly, this ground of the Application for Review is dismissed.

Review Ground 2 - The Rate of Change

77. In developing a forecast of the operating expenditure of gas distributors for the third regulatory period for the purpose of setting tariffs under the Code the Commission takes a base year of operating expenditure, 2006, and then applies a forecast annual rate of change. One element of this forecast is the determination of a value for operating expenditure partial factor productivity (opex PFP).

78. In its Final Decision the Commission declined to approve the Applicant's proposed value of 1.41% per year for opex PFP. The Commission instead approved opex PFP of 2.87% per year.

79. The selection of opex PFP feeds directly into the calculation of the Applicant's forecast operating expenditure for the period covered by the Access Arrangement, and therefore into the calculation of the Applicant's required revenue for each year.

80. Section 8.37 of the Code, which provides for the recovery of operating costs, states:

> "A Reference Tariff may provide for the recovery of all Non Capital Costs (or forecast Non Capital Costs, as relevant) except for any such costs that would not be incurred by a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the Reference Service."

81. The Code does not specify methodology for developing an operating expenditure forecast, but the Commission set out its preferred method for developing an operating expenditure forecast in its first Consultation Paper (May 2006). The Commission's approach involves several stages. First, it ensures that base year operating expenditure is efficient and does not include items of a non-current nature. Second, the verified operating expenditure for 2006 is extrapolated to 2007 using the rate assumed in reference tariffs for the second regulatory period. And lastly, the annual rate of change for the third regulatory period is applied to obtain forecasts of operating expenditure for each year over 2008 to 2012. The process also allows for step changes in operating expenditure to be included.

82. The Applicant and the Commission agree that this methodology for calculating operating expenditure is appropriate. They are also agreed on the mechanism for calculating the future rate of change in operating costs (the change in the cost of inputs, less operating productivity improvements, plus changes in the volume of output, less CPI inflation). They agree on each component of that formula *except for* operating productivity improvements, that is the change in opex PFP.

83. All components of the rate of change formula applying in the third regulatory period are forecasts. Section 8 (2)(e) of the Code requires that "any forecasts required in setting the Reference Tariff represent best estimates arrived at on a reasonable basis."

84. The Applicant proposed opex PFP of 1.41% per year and a rate of change of 1.44% per year. The Commission's opex PFP of 2.87% per year is consistent with a rate of change of –0.02% per year.

85. The Applicant contended that the Commission's decision not to approve its proposal for opex PFP constituted, under Section 39 (2) of the Law, either an error of fact and/or an incorrect or unreasonable exercise of discretion, or, alternatively, a purported exercise of discretion where the occasion for the Commission to exercise discretion did not arise.

86. As to the third ground, the Panel has previously indicated its view of the effect of the Gasnet decision. Consistently with this view the Panel does not consider that this issue is one which attracts the Gasnet principle. In considering the rate of change issue, and, in particular, opex PFP, the Commission was required to exercise a discretion between varying forecasts in order to arrive at a best estimate on reasonable grounds.

87. The matters remaining to be determined are therefore whether the Commission made an error of fact or incorrectly or unreasonably exercised its discretion in not accepting the Applicant's proposed opex PFP of 1.41%.

88. In its initial submissions to the Commission, the Applicant relied upon a number of reports by experts to support its proposed value for opex PFP. Initially, the Applicant

proposed an opex PFP of 0.8% per year, based on a report by Meyrick and Associates. The conclusion in the Meyrick report that 0.8% per year is an appropriate forecast was based on a number of studies relating to electricity and gas distribution in Australia and the US, including earlier work by Meyrick on total factor productivity. That earlier Meyrick report relies on historical data and forecasts provided by the three Victorian gas distributors.

89. The Commission engaged the Pacific Economics Group (PEG) to review the reports prepared by Meyrick and Associates. PEG found that, in relation to opex PFP, the information sources used by Meyrick to support its recommendations were either not accurate, not objective, did not reflect the distributors conditions or were not internally consistent.

90. In its initial report PEG estimated opex PFP using two models, both of which employ variables relating to measures of output, input prices and other business conditions (the proportion of non-ferrous pipe, the nature of the customer base, the physical size of the network and capital employed). The first model was developed using data for US gas distributors and then applied to the Victorian gas distributors. The second model was developed using Meyrick's data on gas distributors in Australian and New Zealand. PEG recommended using a composite model relying on elements of both the US and Australia/New Zealand models.

91. Based on this modelling PEG provided a forecast opex PFP of 2.78% per year for the Applicant. This was consistent with a rate of change in real operating expenditure of –0.92% per year.

92. In its draft decision, the Commission concluded that shortcomings in Meyrick's analysis would likely produce a downward bias in the Meyrick estimate of opex PFP proposed by the Applicant. The Commission instead proposed the opex PFP derived from the PEG modelling.

93. The Applicant then obtained further analysis from Meyrick criticising the econometric analysis undertaken by PEG and also obtained an expert report from Horton 4 Consulting which was critical of PEG's approach and its conclusions. The main

criticisms were, firstly, as to the mixing of parameters in the composite model and, secondly, the unexpected result that an increase in capital inputs is associated with higher, rather than lower, operating costs.

94. Meyrick held to its initial forecast of opex PFP of 0.8% per year, while Horton couched its conclusions in terms of total factor productivity growth, stating "that there is no reason to expect normal energy distribution TFP growth to differ from that in the economy as a whole." The Applicant contended that the Horton approach implied opex PFP of 2% per year.

95. Having regard to this material the Applicant submitted revisions to its proposed access arrangements including an amendment of its proposed opex PFP forecast to 1.41% per year and, consequently, its proposed rate of change to 1.44% per year.

96. The Commission engaged PEG to review the proposed revisions submitted made by the Applicant and the opinions of the Applicant's consultants. As part of this process, PEG departed from its earlier model developed using Meyrick's data on gas distributors in Australian and New Zealand, due to its stated view that the quality of this data and econometric results flowing from its use was not sufficiently persuasive. PEG also amended its inputs to reflect the Commission's change to forecast rate of CPI inflation (to 2.7% from 2.6%) and allowed capital expenditure. The resulting opex PFP for the Applicant was 2.87% per year, contributing to a rate of change of –0.12% per year.

97. In its Final Decision the Commission adopted the opex PFP and rate of change calculated by PEG in its later report on the basis that these constituted best estimates arrived at on a reasonable basis. A further revision to the rate of CPI inflation (to 2.6%) after the Final Decision lifted the Applicant's rate of change to –0.02% per year.

98. In its submissions to the Panel the Applicant contended that the Commission had already pared back the Applicant's reported base year costs, but had not identified further inefficient or imprudent costs. The Applicant maintained that it had already made very significant productivity improvements to the extent that it should be

regarded as an efficient company. As such, the scope for it to make further productivity improvements is less than that applicable to an inefficient company.

99. It also argued that the Commission had failed to recognise that specific companies exhibit different rates of productivity improvement dependent upon their current levels of efficiency. Accordingly, it stated that the Commission's approach of applying a purely mathematical model, particularly one based upon US data, was wrong. It referred to the previous acknowledgment by PEG that, in comparative terms, Victorian gas distributors, including the Applicant, were efficient.

100. The Applicant also made submissions on cost overshooting, which occurs when base year costs are cut to unsustainably low levels, stating that:

(a) PEG had previously concluded that there is a significant probability of cost overshooting in relation to Victorian distributors, and

(b) The Applicant had provided evidence of cost overshooting on its own part.

101. The Applicant contended that, under the Commission's methodology, it was probable the opex PFP factor had been applied to an unsustainably low level of base expenditure, leading to unsustainably low forecasts of operating expenditure for the third regulatory period.

102. The Applicant strongly criticised the econometric approach adopted by PEG on several bases including its eventual reliance upon US rather than Australian and New Zealand data, the use of an incorrect algebraic sign for one coefficient and that it broadly constituted a disaggregated approach. It argued that its own expert material was more persuasive and should have been accepted in preference to that of PEG.

103. In response the Commission argued that the Applicant had established no basis for the acceptance of its middle course opex PFP estimate of 1.41%. It argued that it was obliged to form an opinion as to the best estimate on a reasonable basis and not to accept a compromise between competing contentions.

104. The Commission disputed the arguments about the calculation of base year opex and contended that there is no conceptual or practical overlap between this and the forecasting of opex PFP. It maintained that its approach properly accorded with sections 8.37 and 8.2 (e) of the Code.

105. The Commission criticised the Meyrick report on several grounds including its focus on total factor productivity rather than partial factor productivity and its reliance upon the gas distributors' own estimates and forecasts. It was argued that this study failed to provide a proper basis for an opex PFP figure of 0.8%.

106. As to cost overshooting and its consequences the Commission argued that there was no evidence of this occurring in the base year of 2006 and no quantification of it by the Applicant. Accordingly, it contended that it was appropriate not to account for this issue.

107. The Commission contended that it acted reasonably and, therefore, correctly in relying on the opinion of PEG and that the criticisms of the PEG methodology by the Applicant were unfounded. On the contrary, it argued that the criticisms PEG itself had made of the data sources relied upon by Meyrick were persuasive.

108. In oral submissions made to the Panel, senior counsel for the Applicant observed in relation to the final PEG reports that "it is a matter for the Panel at the end of the day as to whether the conclusion that PEG is expressing in its report was well founded or not". This, in the Panel's view, is partially correct. The more appropriate test is whether it was reasonably open to the Commission, as a matter of judgment, to accept the conclusion that PEG reached rather than that reached by Meyrick in arriving at a best estimate on a reasonable basis.

109. In the Panel's view the Commission's approach to the estimation of opex PFP and the rate of change has been to rely upon an objective quantitative analysis undertaken by a qualified and experienced consultant. This is not to deprecate the qualifications and experience of the Applicant's experts. It is clear, however, that there is a divergence of opinion between the various experts requiring the exercise of judgment by the regulator.

110. It is not entirely clear, in any event, how the Applicant derived its proposed opex PFP forecast from these various sources except to concede that there was material which could suggest that the real rate might be higher than 0.8%. In addition, the figure of 0.8% per year proposed by Meyrick does not itself appear to the Panel to derive from an entirely objective analysis, and the opex PFP estimate of 2% that the Applicant assigns to Horton seems to be based on a series of general assumptions.

111. In a sense the fact that the Applicant chose to submit a figure not expressly supported by its own experts clearly illustrates the fact that this process required the exercise of judgment on the part of the Commission.

112. Accordingly, faced with these divergent views, some less than conclusive, and involving differing methodologies, the Commission was required to make judgments in relation to competing factors arising from the various reports. The Panel considers that, in these circumstances, it was reasonably open to the Commission to rely upon the advice received from its own expert in arriving at a value for opex PFP and consequently a forecast for rate of change.

113. The Appeal Panel finds that the Commission was not in error in rejecting the Applicant's proposal an opex PFP of 1.41% and rate of change of 1.44% per year and substituting its own values of 2.87% and -0.02% respectively. Neither was there, on the part of the Commission, a wrong or unreasonable exercise of discretion in reaching this conclusion.

114. Accordingly, this ground of the Application for Review is dismissed.

Roderick Smith
Chairman
On behalf of the Panel:

Roderick Smith (Chair)
Marina Williams-Wynn
Beverley Honig

Opex Rate of Change and Productivity: Response to Consultant Reports

Final Report

Pacific Economics Group, LLC
Economic and Litigation Consulting

Opex Rate of Change and Productivity: Response to Consultant Reports

Final Report

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1. Introduction and Summary

The Essential Services Commission (ESC) is undertaking a gas access arrangement review (GAAR) for the three gas distribution businesses (GDBs) serving Victoria (Multinet, SPAusNet, and Envestra). A central part of the new GAAR is determining revenue requirements over the term of the upcoming arrangement. An important component of each company's revenue requirements is its operating expenditures (opex).

Over the term of the GAA, the growth in allowed opex will be determined using a "rate of change" formula. Setting the terms of the rate of change formula requires estimates of input price inflation (for labor and non-labor opex inputs), growth in opex partial factor productivity (PFP), and growth in GDB output during the term of the GAA. Because it is expressed in "real" terms, the rate of change formula also requires an estimate of CPI inflation for the same period.

Australia's National Third Party Access Code For Natural Gas Pipelines (the Gas Code or the Code) imposes certain requirements for setting these terms and the rate of change formula more generally. Two sections of the Code are most relevant in this regard. Because the rate of change formula is a forward-looking calculation that relies on forecast information, the parameters chosen for the rate of change formula must comply with Section 8.2 (e) of the Code, which states that "any forecasts required in setting the Reference Tariff represent best estimates arrived at on a reasonable basis." In addition, because the rate of change formula adjusts the GDBs' non-capital costs, the parameters of the formula must comply with Section 8.37 of the Code, which says "a Reference Tariff may provide for the recovery of all Non Capital Costs (or forecast Non Capital Costs, as relevant) except for any such costs that would not be incurred by a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the Reference Service."

In its report *Victorian Gas Distribution Business Opex Rate of Change*, 26 March 2007 (Meyrick 2007b), Meyrick and Associates (Meyrick) presented recommendations on the parameters used to calibrate the opex rate of change formula. Meyrick's recommendations would lead to 2.66% average annual growth in real opex for Victoria's

GDBs over the term of the GAA. The rates of change differed for individual GDBs because of differing projections for output growth.

The ESC asked Pacific Economics Group LLC (PEG) to evaluate whether Meyrick's recommendations were consistent with the Code requirements and, if not, to present alternative recommendations. PEG's review concluded that Meyrick's recommendations for opex PFP growth, labor price inflation and CPI inflation were not consistent with the Code. PEG's alternative recommendation for labor price inflation was based on a weighted average of inflation forecasts developed by Access Economics in 2007 (AE) and BIS Shrapnel (BIS), with five-sixths weight placed on the AE forecast. Our PFP recommendation was based on an econometric decomposition of PFP trends, which PEG originally developed and which Meyrick found to be "well grounded in economic theory."[1] PEG's econometric decomposition was tailored to the expected change in business condition variables, or "PFP drivers", for each of the GDBs over the term of the GAA. Our recommendation for CPI inflation was identical to that assumed by the ESC for all elements of the "building block" calculations for revenue requirements over the term of the GAA which, in turn, were used to set P_0 and X factors for each GDB.

Overall, PEG's recommendations would lead to -0.5% growth in real opex over the term of the GAA. Our recommended growth rates for individual GDBs also differed to reflect differing forecasts in output and PFP trends. These individual GDB output growth and PFP trends led to average annual changes in real opex of 0.58% for Envestra, -0.92% for Multinet and 0.14% for SPAusNet.

Meyrick responded to PEG's recommendations in an October 15 report entitled *Response to Pacific Economics Group on Meyrick Opex Rate of Change and Productivity Reports* (Meyrick 2007a). In this updated report, Meyrick now recommends that opex grow at a rate of 3.46% above CPI over the term of the GAA. BIS Shrapnel has also responded to PEG's review of its work on labor price inflation. Two GDBs (SPAusNet and Alinta, acting on behalf of Multinet) also commissioned a review of PEG's work from Horton 4 Consulting (Horton). Horton raises some issues regarding PEG's work that were not previously discussed by Meyrick; in particular, Horton argues that PEG should have considered a "dynamic" econometric specification, believes that km of pipe

[1] Meyrick (2007b), *op cit*, p. 3.

should have been considered as a scale variable, and contends that an "aggregate approach" that examined "operating expenditure productivity growth" would have made it difficult to justify PEG's conclusions for unit operating costs.

PEG welcomes the new information that has been provided during the GAAR and believes new evidence can be relevant for developing "best estimates" of the parameters used to set the rate of change formula. In this regard, PEG believes that new information has come to light that is relevant for setting the growth in real opex over the term of the GAA. In particular, in a Draft Decision for SPAusNet's transmission operations in Victoria, the Australian Energy Regulator (AER) wrote that it "accepts that SP AusNet's proposed real labour growth escalator of 2.8%, based on the nominal rate of 5.7%, is a realistic expectation of increases in the cost of labour in SP AusNet's forthcoming regulatory control period."[2] This Draft conclusion rests primarily on a report the AER commissioned from Econtech, which was asked to review the AE labor price inflation study (which the AER also commissioned). Econtech's review projected more rapid labor price inflation than AER had forecast and, at least for the time being, the AER has accepted this conclusion. The debate on labor price inflation in Australia may still evolve, but it is significant that the AER has undertaken a more detailed analysis of this issue than either Meyrick, PEG or any other party commenting on the rate of change issue in the GAAR. PEG therefore believes that the AER's research on this issue can be viewed as a best estimate determined on a reasonable basis, and we accept its conclusion to adopt a forecast of 5.7% annual inflation in labor prices over the term of the GAA. This is the same forecast that has been proposed by each of the GDBs.

In addition, PEG has reconsidered its use of Meyrick's ANZ database for the purposes of econometrically estimating PFP "drivers" and subsequently projecting PFP trends. Our report clearly stated (*e.g.* pp. 63, 66, 69) that the ANZ data and econometric results were inferior to those developed using US data. Nevertheless, the ANZ econometric results were "generally plausible" and did seem to reflect some ANZ trends (particularly the elimination of productive inefficiencies by Victoria GDBs, p. 69) that were also evident in Meyrick's PFP research but differed from trends in the US. We

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[2] Australian Energy Regulator (2007), *SP AusNet transmission determination 2008-09 to 2013-14,"* Draft Decision, p. 141.

therefore believed that our ANZ econometric model was capturing some effects that were unique to the local environment and potentially relevant to projecting PFP trends. On further reflection, however, we believe the only unique factor evident in the ANZ econometric model – the elimination of productive inefficiencies in Victoria – is a factor that is not expected to persist in any case (at least at comparable magnitudes) over the term of the GAA. The ANZ econometric model therefore did not identify any factors relevant for forecasting PFP for the GAA. Given this, and the relative strengths of our US sample, PEG finds that the econometric model estimated with Meyrick's ANZ database adds no value to our US econometric research. We will therefore rely only on the US econometric results for PFP recommendations.[3]

PEG has also updated our rate of change recommendations to reflect adjustments that the ESC has made to its inflation assumptions and allowed capital expenditures. The ESC's forecast rate of CPI inflation factors directly into the rate of change formula. Allowed capital expenditures also indirectly impact PFP growth since, in PEG's econometric model, changes in capital spending will affect projected PFP growth. Since the ESC has revised its CPI and capital expenditure forecasts, the impact of those changes should also be reflected in the rate of change formula.

With these exceptions, however, none of submissions by Meyrick (2007a), Horton or any of the GDBs contains new information that either supports their recommendations or warrants further adjustments to the rate of change formula. Most importantly, the foundations for Meyrick's recommended PFP growth rate remain plainly deficient. Meyrick's response has not addressed the main weaknesses that PEG identified in its original report. Moreover, Meyrick is not accurately reporting the available evidence on PFP growth, and its report often obfuscates the relevant facts. The Meyrick analysis simply provides no reliable information that can be the basis for an objective estimate for the GDBs' projected opex PFP growth, so an alternative estimate *must* be developed to satisfy sections 8.2(e) and 8.27 of the Gas Code.

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[3] It should be noted that, because PEG was dependent on being provided the ANZ data by Meyrick, we had a relatively limited amount of time to analyze these data and consider their implications before our report to the ESC was due. If we had more time, PEG would have likely come to the same conclusion as in this report and would not have used the ANZ econometric results to project PFP trends.

Meyrick also makes a number of criticisms of PEG's econometric projection of PFP trends, but (now that the estimates developed from ANZ data have been withdrawn) these arguments are also unfounded. Most of these points involve a disparagement of PEG's functional specification (the translog cost function) and use of US data to estimate cost function parameters. However, on the *same day* that Meyrick finalized its rate of change recommendations, it was completing a report that also used the translog cost specification and US sample data to assess gas distributor cost efficiency for the purposes of setting allowed opex in the GAAR. Fortunately, the record demonstrates that there is no merit for Meyrick's most recent position on these issues, since PEG's econometric methods and data are rigorous and well grounded in the economics literature.

Meyrick also says that a "major problem" in our econometric model is that the capital coefficient in our short run cost model has a positive sign. However, this criticism shows no apparent awareness of the relevant empirical literature. It is true that, in theory, the coefficient on the capital term in a short run cost model should be negative, but in *practice* this theoretical prediction is often not confirmed. Indeed, the finding of positive coefficients on capital stock variables in short run cost models is so common that an "intense debate" has arisen in the literature about why this theoretical result so often fails to hold.[4] Some of these explanations are particularly relevant to utility industries such as gas distribution. Positive coefficients on capital stock variables in short-run cost models are therefore not perceived as a "major problem" that leads peer-reviewed academic journals to reject papers submitted on this topic. Indeed, PEG's econometric results are consistent with much of the peer-reviewed, published literature, and our familiarity with this work enhanced our confidence in our results. It should also be noted that at least one GDB submission on the Draft Decision contains information that supports PEG's finding regarding the coefficient on the capital stock variable.

Horton's criticisms of PEG's econometric results and PFP recommendations are also unfounded. Its point regarding the merits of "dynamic" specification displays a misunderstanding of PEG's econometric methods, as does its erroneous view that PEG's

[4] Fraquelli, G., M. Piacenza, and G. Abrate (2004), "Regulating Public Transit Networks: How Do Urban-Intercity Diversification and Speed-Up Measures Affect Firms' Cost Performance?," *Annals of Public and Cooperative Economics*, 75:2, 193-225, p. 212.

econometric decomposition does not include an adjustment for changes in the km of pipe. PEG also demonstrates that Horton's conclusion regarding "operating expenditure productivity growth" is mathematically untrue. Horton's critique also repeatedly fails to properly identify partial factor productivity growth in the equations or "productivity" concepts it advances and contains mistakes in basic statistical inference.

Based on this new information, PEG revises its labor price inflation rate to 5.7% and its rate of industry PFP growth to 2.47%. We also adopt the ESC's assumption of CPI inflation over the GAAR of 2.7%. The output growth forecast is now based on the cost elasticity shares from PEG's US econometric model and updated ESC forecasts for customer and volume growth, which leads to a change in the output term from 1.93% to 1.79%. There has been no change to the recommended inflation in non-labor opex prices. The new information leads to an average rate of change in opex of 1.14% in real terms over the GAA. The associated rates of change for SPAusNet, Envestra and Multinet are 1.64%, 1.83% and -0.12%, respectively.

Our report is organized as follows. Chapter Two reviews the criteria that were used to evaluate whether any given estimate used in a rate of change formula represents a "best estimate arrived at on a reasonable basis." Chapter Three evaluates Meyrick's response to PEG's recommendations for the parameters of the rate of change formula. Chapter Four evaluates the Horton response to PEG's report. Chapter Five presents concluding remarks and revised rate of change recommendations for the industry and individual GDBs. An appendix discusses some points regarding the "overshooting" issue. It should also be noted that this report does not attempt to respond exhaustively to the points raised by Meyrick, Horton or the GDBs in response to PEG's initial report. Rather, this report focuses on what PEG has identified as being the most significant issues requiring a response. Where this report does not respond to any particular issue raised by Meyrick Horton or the GDBs, this should not be interpreted as acceptance of its validity by PEG.

2. Evaluation Criteria

PEG's report specified a set of criteria that we used to evaluate whether opex forecasts were consistent with Sections 8.2(e) and 8.27 of the Gas Code requirements. Our criteria applied only to the opex rate of change formula and whether the parameters in that formula satisfied Sections 8.2(e) and 8.37 of the Code. Section 8.2(e) states that "any forecasts required in setting the Reference Tariff represent best estimates arrived at on a reasonable basis." Section 8.37 says that reference tariffs may recover forecast non-capital costs "except for any such costs that would not be incurred by a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the Reference Service." The Gas Code therefore explicitly does not allow costs to be recovered if they would not have been incurred by a prudent service provider acting to achieve the lowest sustainable cost of service.

PEG established these criteria because we wanted to be as clear as possible regarding the bases for our conclusions. Because setting the opex rate of change involves disparate evidence from multiple sources, it is also possible that a given piece of evidence will not satisfy all criteria equally. Whenever there are conflicts or tradeoffs regarding the relative merits of available evidence, reaching an overall conclusion involves judgments about the relative importance of each criterion.[5] Reasonable people may disagree about these judgments, but the transparency of the decision-making process will be enhanced when these assessments are as explicit as possible.

Meryick agrees with many of the criteria proposed by PEG but says "it should be emphasised firstly that these criteria are simply ones proposed by PEG" and "have no official status with regard to the Gas Code."[6] It is not clear why such an obvious point needs to emphasized; naturally the criteria that appear in our report are the ones we are proposing, and if the Code included more official criteria for, say, determining "best estimates" then PEG would not need to develop more explicit standards. Since this is not

[5] It may also involve judgments about "how much" more the available evidence satisfies one criterion versus another.

[6] Meyrick (2007a), p. 3.

the case, PEG believes there is value in putting forth specific criteria to evaluate the evidence that will be used to operationalize the provisions of the Code.

PEG's report also contains a discussion of cost sustainability and the implications for allowed opex if a GDB "overshoots" sustainable costs because of excessive cost cutting. This discussion essentially responded to points the GDBs' consultants raised regarding these issues, but we believe that Meyrick and others have incorrectly concluded that our analysis of "overshooting" is central to PEG's overall recommendations. This is not the case. Nevertheless, we believe it is important to clarify some of the misconceptions regarding the "overshooting" issue, and we discuss these points in the Appendix to this report.

3. Evaluation of Meyrick Response

3.1 Non-labor prices and labor/non-labor shares of opex

Meyrick's original recommendations for inflation in the prices of non-labor opex inputs and the share of labor in opex were drawn from PEG's TFP and PFP work for Victoria's power distribution industry. Meyrick originally recommended that inflation in the prices of non-labor inputs be set at 2.6% per annum, which was the average annual inflation rate in 2000-2005 for the producer price indexes PEG used to measure changes in non-labor opex prices. PEG concluded that these recommendations were reasonable and consistent with Sections 8.2(e) and 8.27 of the Gas Code.

Meyrick has revised those estimates in its Response report. Meyrick's new proposal would apply different producer price indices (PPIs) to the meter data services, billing and revenue collection opex, advertising/marketing opex and SCADA maintenance opex. For the first three of these categories, Meyrick believes PEG's choice of PPI is too "high level" and proposes to use a weighted average of more disaggregated PPIs that it believes more closely reflect the activities in the opex category. However, Meyrick does not have any data on what shares of opex within each of these categories are associated with the more disaggregated activities. Lacking these data, Meyrick simply applies equal weights to two different PPIs and substitutes these constructs for PEG's selected PPI. The fourth opex category is SCADA maintenance, for which Meyrick proposes to substitute computer maintenance for the computer services PPI.

Meyrick's revised indexes for the first three opex categories are clearly unwarranted. In all cases, Meyrick makes conjectures about what share of costs might be in that category without having any data to support those conjectures. The weights that are applied to the proposed disaggregated indices are therefore arbitrary, unlike the weights that were previously used in Meyrick's (and PEG's earlier) analysis, which were firmly tied to specific data on cost shares. Meyrick's proposed modifications would therefore not improve the extent to which these indices are "best estimates determined on a reasonable basis."

There are also compelling reasons not to adjust the SCADA maintenance PPI. In particular, because it is a technically complex area, SCADA maintenance is likely to involve computer consultancy as well as computer maintenance services. The computer services PPI selected by PEG includes both of these activities whereas Meyrick's proposed alternative does not. We therefore believe that this proposed adjustment also does not improve the extent to which the non-labor opex price index is consistent with a best estimate determined on a reasonable basis and do not accept Meyrick's proposal.

3.2 Labor Prices

PEG's original report recommended that labor price inflation be based on a weighted average of the forecasts in the Access Economics (AE) (2007) and BIS Shrapnel reports, with five-sixths of the weight on AE (2007). Meyrick recommended using the BIS Shrapnel forecast rather than an earlier version of the AE projection. Meyrick's Response has updated its labor price inflation recommendation to incorporate the Econtech forecast.

Before we assess these studies, it is important to recognize that both PEG's and Meyrick's labor price inflation recommendations were based on a second-hand analysis of other consultants' forecasts. The current salience of wage inflation in Australia has led to a robust, and evolving, debate on this issue. PEG's review considered new information (*i.e.* the AE (2007) report) that was not available at the time of Meyrick's recommendation. We ultimately relied on AE (2007) rather than its previous report since the updated analysis clearly superseded and was superior to what AE first presented. Meyrick's Response has now referenced a new report by Econtech that became public only after PEG completed its review.

PEG believes that new, relevant information on labor price inflation must be considered to comply with the "best estimates" provision of the Gas Code. At the same time, a proper assessment of the evidence presented on labor price inflation in the GAAR must be based only the information that existed at a given point in time. It is fatuous to claim *ex post* vindication of any specific recommendation because of analysis that was released after that recommendation was developed. Moreover, while empirical recommendations are clearly necessary for the rate of change formula, the underlying principles and the analytical framework used to evaluate disparate evidence are also critical, particularly in terms of precedent and setting the terms of future debate on these issues.

PEG's review of Meyrick's recommendation concluded that there were strengths and weaknesses of the BIS wage forecast. The main strength was the choice of wage index. There were three main weaknesses: the recommendation was based only on forecast wage inflation for male workers rather than all workers; the wage inflation forecast was not specific to labor market conditions in Victoria; and BIS Shrapnel acknowledged that there were considerable uncertainties associated with its wage forecast.

After carefully reviewing Meyrick's Response to our original report, PEG believes that most of these identified deficiencies of the BIS report remain valid. Meyrick's Response either ignores critical points that we raised or distorts important facts. For example, on the use of male wage forecasts instead of workforce forecasts, Meyrick says that "based on available evidence on the gender composition of the GDB workforce and likely competition for GDB staff from a range of related sectors, not just mining and construction, we conclude that BIS Shrapnel's use of the male AWOTE is unlikely to cause significant bias and thus reject PEG's criticism." However, Meyrick's Response pointedly ignores the "available evidence" in the BIS Shrapnel report on this bias that PEG also highlighted. As we wrote,

> …PEG believes there is a significant probability that the wage measure used by BIS Shrapnel to project labor prices will overstate wage growth for all workers employed by the GDBs. The BIS Shrapnel report also appears to provide some historical evidence supporting this position. Table 4.2 presents data on AWOTE growth in 2001-06 for all full time adult workers for different industry sectors, including EGW. Table 4.3 presents data on AWOTE (and LPI) growth for male workers only in the EGW sector. The growth rates in each table are for the year ending in May. Since Tables 4.2 and 4.3 differ in terms of whether they apply to all workers or only male workers, differences in EGW average wage trends between the tables will primarily (and perhaps entirely) reflect how differences in the male-female composition of the EGW workforce affect the industries' overall wage trends. Over the 2001-06 period, Table 4.2 shows that inflation in AWOTE for the entire work force averaged 4.7% per annum, while Table 4.3 shows that inflation for male workers averaged 5.2% per annum. This evidence supports the view that relying on wage forecasts for male workers only can overstate the actual growth in wages paid to all EGW workers.[7]

[7] Kaufmann (2007a), *op cit,* p. 25-26.

This historical difference between wage growth for male workers and all workers is clearly material for evaluating wage forecasts. Meyrick recommended a wage index that applies to that segment of the GDB workforce where wages have in fact increased most rapidly. If this historical disparity persisted in the future, it would lead to a biased wage forecast for the entire workforce. Any responsible assessment of the "available evidence" must consider the actual evidence that exists and which demonstrates that there has been a difference in wage growth between male and female EGW workers in the very recent past. As a methodological matter, it is also undeniable that a wage index for all workers is more representative of wage pressures than a wage index only for male workers. PEG believes that, when calibrating a rate of change formula, there is simply no legitimate reason to use a male only wage index if an analogous index exists for the overall workforce.

Similarly, it is more reasonable to rely on wage forecasts that are specific to the State in which a GDB is located than to wage forecasts for all of Australia. PEG's report highlighted that labor markets are far more "local" than the markets for most other goods and services. Differences in labor supply and demand among regions can therefore cause wages to grow at different rates in different States and cities. Meyrick does not dispute this analysis but instead defends its national forecast by saying that PEG "ignores information available in the Access Economics (2007) report favoured by PEG which shows that Victoria had the third highest rate of increase in the composite energy wage index and was slightly above the national average." PEG did not "ignore" this information but concluded that the relative ranking of Victorian wage trends vis-à-vis other States and the national average is irrelevant. If wage pressures are greater in Victoria than the nation, the rate of change formula should recognize this and not rely on an overly-aggregated index that does not reflect local conditions. Again, PEG believes the fundamentals of labor market economics make this conclusion essentially indisputable, and this principle should be reflected in the wage measures used in the GAAR and related regulatory decisions.

PEG also believes that an objective analysis of the BIS report shows there is considerable uncertainty about their wage forecasts and the economic scenarios that underpin them. This uncertainty invites caution about simply accepting their forecasts as the basis for a labor price forecast. As we noted in our original report

> BIS Shrapnel acknowledges that that "there is significant uncertainty surrounding the wages outlook"[8] It also notes that in spite of recent tightening in the labor market in 2006, wage growth has not accelerated. BIS Shrapnel also prepared a companion report for Envestra that examined the outlook for construction costs and implicit price deflators.[9] This report noted that "(i)t is difficult to extrapolate the historical impact of cycles in engineering construction activity on construction costs, as measured by the engineering construction implicit price deflator. While engineering construction activity rose substantially between 1991/92 and 1999/2000, the implicit price deflator trended sharply lower in real terms between 1991/92 and 1996/97, before picking up again only over the second half of the decade."[10] BIS Shrapnel posits several factors that may have contributed to "the relatively weak historical correlation of the engineering construction implicit price deflator and total engineering activity," and argues that these factors have likely run their course.
>
> PEG believes that BIS's acknowledgement of its forecast errors in the past, and the uncertainties surrounding the future wage outlook, demonstrate the difficulties of projecting wage growth accurately. One reason for these difficulties is that many alternative scenarios can evolve and affect the demand for labor.[11]

We believe this analysis remains valid. The "significant uncertainty surrounding the wages outlook" was also central to why PEG believed it was appropriate not to rely entirely on the BIS Shrapnel evidence. Given the information that was available to us at the time, we continue to believe this recommendation was warranted.[12]

However, the Econtech report represents a significant source of new information. Econtech's labor price forecasts were developed during a price review for SPAusNet's transmission operations in Victoria and project wage trends for Victoria. These forecasts

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[8] BIS Shrapnel (2007a), *op cit*, p. 15.

[9] BIS Shrapnel (2007b), *Engineering Construction Implicit Price Deflator*, Report prepared for Envestra.

[10] BIS Shrapnel (2007b), *op cit*, p. iv.

[11] Kaufmann (2007a), p. 29.

[12] However, BIS Shrapnel's response (2007c) to PEG makes a useful suggestion on how the AE (2007) and BIS forecasts can be combined. PEG's original report found BIS's selected AWOTE measure was preferable to AE's LPI. BIS recommended that, if the BIS and AE (2007) forecasts are to be used jointly, any bias between these measures be quantified directly using observed historical data on differences between the growth rates for these indices. PEG believes this recommendation is more direct, transparent and in all likelihood accurate than the approach adopted in our original report. While we have not examined the actual empirical value that BIS proposed to quantify this bias, we do believe this is a constructive suggestion that merits attention in future proceedings.

also (apparently) apply to the entire workforce. The Econtech forecasts are therefore consistent with PEG's recommendations and superior to those proposed by Meyrick on these important grounds.

It is also important that this report was commissioned by the AER, which also commissioned the AE labor price forecasts. The AER has accordingly undertaken a more detailed analysis of this issue than Meyrick, PEG or any other party commenting on the rate of change issue in the GAAR. While the debate on labor price inflation in Victoria may continue to evolve, the AER's extensive research on this issue is noteworthy. PEG therefore accepts the conclusion in the AER's Draft Determination to adopt a forecast of 5.7% annual inflation in labor prices over the term of the GAA. This is the same forecast that has been proposed by each of the GDBs.[13]

3.3 Partial Factor Productivity Trends

Meyrick recommends an opex PFP trend of 0.8% for the rate of change formula. Meyrick essentially supports this recommendation using four sources of material. The first is Meyrick's own estimates of the GDBs' historical opex PFP growth and their projection for opex PFP growth over the term of the GAA. The second is BIS Shrapnel's estimates of PFP growth for Australia's utilities' sector. The third is information on productivity growth for utility industries in North America. The fourth is precedents on (explicit or implicit) PFP growth trends that other Australian regulators have adopted in price controls for energy distributors. In its original report, PEG evaluated these foundations for Meyrick's PFP recommendation and found each was fundamentally flawed and therefore could not be used to develop an objective estimate of sustainable opex PFP gains. There is nothing in Meyrick's (2007a) defense of its work that warrants an adjustment of PEG's analysis, as we explain below.

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[13] PEG also wishes to correct an error that appears in our evaluation of the labor price inflation issue. On page 32, we write that "Real wages have grown in those sectors that have been most impacted by greater demand for mining and construction labor; for example, ABS data show that utilities wages have grown by about 1.2% annually in real terms between December 2003 and December 2006." The word "relative" was inadvertently omitted between "utilities" and "wages" in the last sentence, so it should read "utilities' relative wages have grown by about 1.2% annually…" This typo was not material to our analysis, and we believed the substance of PEG's point should have been clear from the context in which we were comparing wage growth among sectors, but in any case this error is corrected here for the record.

3.3.1 Meyrick Estimates and Projections of GDB PFP Growth

The first piece of material that Meyrick uses to support its PFP recommendation is the GDBs' projection of PFP growth. Meyrick developed this PFP forecast using information on the GDBs' projected outputs, operating expenditures and opex input prices over the term of the GAA. Opex PFP growth is defined as the growth in comprehensive output quantity minus the growth in the quantity of opex input. The growth in output quantity is weighted average of growth in the GDBs' specific outputs, where cost elasticity shares serve as weights. Opex input quantity is equal to the growth in opex minus the growth in the opex input price index.

PEG's original report noted that there were two fundamental problems with using GDBs' projected opex PFP growth, as calculated in the manner above, as a basis for a PFP recommendation in the opex rate of change formula. One issue is the possibility of cost "overshooting" and its implications for future PFP growth, which is discussed in the Appendix of this report. PEG's main concern, however, is that Meyrick's projection is not an objective measure of PFP growth. As we originally stated

> …the information used to develop the opex PFP forecasts is not objective. Indeed, using the GDBs' forecast opex data to forecast their opex PFP is inherently self-referential, and it leads to an inexorable link between the assumptions and conclusions of the analysis. Any projection of operating expenditures over a future period necessarily, and unavoidably, involves assumptions on how opex productivity will change over that period. Using GDB cost projections to project their PFP growth is therefore akin to saying "company projections indicate that opex PFP growth will be lower because the company's opex projections embody lower PFP growth assumptions." If the companies had, instead, assumed that PFP growth would grow more rapidly, their projected opex over the term of the GAA would be lower, which leads inevitably to greater projected PFP growth. It is not reasonable to use self-referential processes of this type to forecast economic variables, since doing so could create an essentially automatic link between the assumptions reflected in company forecasts and regulators' ultimate decisions. Any reasonable basis for determining rate of change parameters must be free from such bias and rely instead on independent, objective information.[14]

Meyrick's Response never addresses these critical points. Instead, it says that "(w)hile we accept that regulators will not want to rely entirely on information supplied

[14] Kaufmann (2007a), pp. 43-44.

by the businesses, it also needs to be recognized that the businesses are the ones who know most about their own operations and the scope for ongoing productivity improvements. Failure to place weight on information supplied by the businesses, or to even consult with the businesses, runs the risk that unrealistically high opex productivity growth rates will be incorporated…"[15] However, consulting the businesses about their "scope for ongoing productivity improvements" and developing self-referential forecasts, as Meyrick and the GDBs have done, are two very different things.

This can be seen by considering the following example. Suppose a new CEO is brought in to manage a company that is thought to be under-performing. One of the new CEO's objectives is to improve the company's productivity. As part of that task, he asks the managers of different company divisions to report on how much they can boost the productivity of their division over the next five years. Suppose that every division, except one, approached this task by developing a list of specific programs, processes and initiatives that they can pursue, each of which has an expected amount of quantified savings. These division managers then used the quantified savings from all initiatives that were determined to be cost effective to calculate their division's expected productivity gains.[16] The remaining division, on the other hand, developed its estimate by stating that this is how much we expect our costs to grow in five years, and this is how much we expect the prices of the inputs we use to increase, and the difference between these growth rates represents our estimate of how much we can improve productivity (expressed either cumulatively or as an annual rate of change).

The contrast between these approaches is striking. The first involves a list of specific, quantifiable activities that can be examined, tested and potentially verified. Such information *could* be useful and provide an objective basis for projecting productivity gains. The latter approach, however, does not provide any such meaningful information, and a shrewd CEO would not be fooled into thinking otherwise. Indeed, all the latter division has done is incorporate an arbitrary *assumption* about its productivity growth into its expenditure forecasts. Expenditures in an initial year will accordingly be

[15] Meyrick (2007a), p. 28.

[16] Of course, this example is somewhat stylized, but because many productivity-boosting programs involve up-front costs, not all potential initiatives to improve productivity will necessarily be cost effective and should be pursued.

escalated by the projected growth in input prices minus this assumed rate of productivity growth. After the increase in input prices is netted out of expenditure growth, all that remains is the assumed rate of productivity growth. The PFP assumption is thereby transformed into the conclusion regarding achievable productivity growth! Thus while all divisions of the business have been consulted about the scope for productivity gains, only the approach adopted by the first set of divisions can potentially provide a basis for objective productivity measures. The latter is inherently self-referential and, ultimately, meaningless.

Meyrick's projection of PFP growth is an example of this latter approach. It relied on company projections of their opex over the term of the GAA and estimated PFP growth as the increase in projected opex minus the projected growth in opex input prices.[17] But, as PEG noted in its original report, "any projection of operating expenditures over a future period necessarily, and unavoidably, involves assumptions on how opex productivity will change over that period." As in the example above, this "leads to an inexorable link between the assumptions and conclusions of the analysis." Whatever PFP assumption a company chooses to build into its opex forecast will determine its "estimate" for projected PFP growth. This analysis is inherently self-referential since the assumptions that appear on the right hand side of the relevant equation (*i.e.* on opex growth and opex input price inflation) completely determine the "conclusion" that is supposed to be calculated on the left-hand side (*i.e.* projected opex PFP growth).[18] Circular reasoning of this type cannot provide a foundation for objective PFP measures for the rate of change formula, but it is at the heart of Meyrick's PFP projections.

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[17] In its initial review, PEG examined the Access Arrangement Information that each GDB provided in March 2007 to see if they contained any objective, quantitative information on how opex PFP was expected to grow over the term of the GAA. None contained any such information but, instead, referenced the Meyrick report – which in turn referenced each GDB's projected expenditures! This again demonstrates the circular, self-referential and ultimately meaningless nature of such PFP projections.

[18] An artist whose work examined "self referential" processes was M.C. Escher. Meyrick's approach of attempting to estimate PFP growth on the left side of the equation by using opex data that embodies PFP growth assumptions on the right hand side is reminiscent of the Escher painting where the left hand is drawing the right hand at the same time the right hand is drawing the left. This painting can be found at the official M.C. Escher website at http://www.mcescher.com/Gallery/back-bmp/LW355.jpg.

Meyrick's comparisons of electricity distribution and gas distribution PFP in Victoria are similarly specious. Meyrick says that "PEG reports apparent differences between the Victorian electricity DB and GDB experience…However, this ignores the comparison of actual electricity DB experience (as calculated by PEG 2006a) and actual *and forecast* GDB experience as reported by Meyrick (2007a, p. 11)…(emphasis added)."[19] Indeed, PEG gives no credence to comparing the actual PFP experience of Victorian power distributors to actual *and projected* PFP for the GDBs because the GDBs' PFP projections are only evidence of what the companies have assumed. It is also fundamentally misleading to compare the observed experience of the electricity DBs to a mixture of experience and unrealized projections for the GDBs. In the current context, "apples to apples" comparisons can only be obtained by comparing "actuals to actuals." PEG's report focuses on observed data and actual outcomes, and this analysis shows that the differences between Victoria's power and gas distributors' PFP experiences are not apparent but real. Below we replicate the table that appeared in our original report (page 41) which summarizes these differences.

Figure 2

Victorian Gas Distributors					
Period	**Total Output Change**	**Total Input Change**	**Opex Change**	**Capital Change**	**Opex PFP Change**
1998-2002	1.63%	-0.62%	-3.80%	1.52%	5.43%
2002-2006	1.89%	-1.09%	-4.79%	0.99%	7.14%
1998-2006	1.77%	-0.85%	-4.12%	1.26%	6.41%
Victorian Electric Distributors					
Period	**Total Output Change**	**Total Input Change**	**Opex Change**	**Capital Change**	**Opex PFP Change**
1995-1999	3.71%	-0.58%	-7.17%	1.85%	10.88%
1999-2003	2.13%	1.25%	0.03%	1.58%	2.09%
1995-2003	2.92%	0.33%	-3.57%	1.72%	6.48%

[19] Meyrick (2007a), p. 25.

This table demonstrates that, in 2002-06, GDBs averaged opex PFP growth of more than 7% per year. At a similar stage after privatization, the electricity distributors were averaging about 2% opex PFP gains. The GDBs are therefore continuing to register very rapid opex PFP gains eight years after privatization, unlike the power DBs. In fact, Meyrick's results show that opex PFP has grown at an even more rapid clip in the two most recent years – by 12% in 2005 and by 8.9% in 2006. These figures therefore reflect the GDBs' *current* opex PFP growth, and this is comparable to the opex PFP growth for the electricity DBs immediately after privatization.

It is important for parties to keep this observed, actual PFP experience in mind when considering appropriate PFP forecasts for the GDBs. Although PEG reiterates its concerns about using power distributors' experience for gas distribution, if anyone did wish to draw parallels between the Victorian gas and power distributors, this table shows that the GDBs' PFP experience is currently much closer to where the electricity distributors were in 1999 than in 2003. The electricity DBs averaged 2.1% opex PFP growth over the four years following 1999. PEG again cautions against drawing superficial parallels between gas and electricity distribution, but it should be recognized that the electricity DBs in Victoria once registered opex PFP growth comparable to what the GDBs are currently experiencing, and the electricity DBs averaged 2.1% opex PFP growth in the years immediately after this period. An objective analysis of the Victorian power distributors' *actual experience* therefore lends more support to PEG's PFP recommendation (*i.e.* future PFP growth in excess of 2%) than to Meyrick's.

In summary, it is unacceptable to derive an opex PFP estimate from a self-referential forecast where assumed PFP growth rates determine the "conclusion" on achievable productivity gains. However, it is appropriate to analyze objective information on PFP growth to determine what PFP gains are achievable. Meyrick uses three additional sources of information to support its PFP recommendation, which we examine in turn.

3.3.2 BIS Projections

Meyrick also supports its PFP recommendation using PFP evidence developed by BIS Shrapnel. In its Response, Meyrick says that "PEG (2007a) attempts to dismiss the relevance of the BIS Shrapnel (2007) forecast of annual labour productivity growth of 0.8

per cent on the grounds that it only applies to labour and not all of opex, applies to the EGW sector and not gas specifically and BIS Shrapnel's historic labour estimates show steady decline whereas the Meyrick (2007b) opex partial productivity estimates show growth over the last several years."[20] In fact, PEG's main concerns go beyond these points, but PEG will consider Meyrick's response to these issues before we turn to our fundamental overall concern with the BIS Shrapnel forecasts, which Meyrick's Response does not address.

Referencing PEG's original report, Meyrick accurately says that "the results of North American studies show that labour productivity and materials and services productivity can move in opposite directions" but demurs that "no evidence is presented that this has been the case in Victoria. Given that the Victorian GDBs have been privatized and subject to incentive regulation for over a decade, they can be expected to be operating at high levels of efficiency and it is, thus, unlikely that the labour and non-labour components of opex would be moving in disparate directions."[21] It is true that PEG has not presented any evidence that labor and non-labor opex PFP have moved in different directions in Victoria. The reason, as Meyrick knows from its own PFP research, is that the Victorian GDBs do not report labor and non-labor opex separately. It is therefore not *possible* to present evidence on this issue for Victoria one way or the other. This point from Meyrick is therefore not relevant; there is no direct, quantitative evidence from Victoria either to confirm or deny that labor or non-labor opex PFP trends are growing at dissimilar (or similar) rates.

Lacking any evidence, Meyrick speculates that it is unlikely that labour and non-labour opex PFP would move in different directions since the firms have been privatized, subject to incentive regulation and are therefore "operating at high levels of efficiency." But simply on an *a priori* basis, this claim is unconvincing. Rational, profit-maximizing firms will respond to opportunities to change their mix of opex inputs if doing so reduces their overall costs. For example, if labor prices rise relative to non-labor opex input prices, all else equal, a firm "operating at a high level of efficiency" would substitute non-labor opex inputs for labor. Similarly, if the relative prices of labor and non-labor

[20] Meyrick (2007a), *op cit*, p. 30.
[21] Meyrick (2007a), *op cit*, p. 30.

inputs are unchanged but there are developments that tend to raise the productivity of non-labor opex inputs vis-à-vis utility labor, then profit-maximizing firms will substitute non-labor opex inputs for utility labor. Either of these developments would cause measured labor and non-labor opex PFP trends to move at different rates, and perhaps in different directions.

These fundamental economics are also relevant to the current conditions in utility industries in Australia and North America. Meyrick's speculation ignores at least two prominent developments in Australia's utility industries in recent years. One is the increased utilization of outsourced services to substitute for functions previously provided by in-house, utility labor. The second is the increasing price of labor relative to other non-labor opex inputs. Both of these issues have received significant attention in the current GAAR. There is also no dispute among parties providing evidence in the GAAR that labor prices are expected to grow more rapidly than non-labor opex input prices over the term of the GAA (the only disagreement has been *how much* faster labor prices will rise). Both of these trends have also been apparent for North American utilities in recent years, although they are probably less significant than in Australia. As PEG's analysis above reveals, both of these trends will tend to create a divergence between PFP trends for labor and non-labor opex inputs. PEG also originally reported that this divergence is in fact apparent in North America, where companies provide disaggregated data on labor and non-labor spending and it is therefore possible to compute labor and non-labor opex PFP trends. Data constraints make it impossible to compute these same, disaggregated PFP trends in Australia, but a combination of the fundamental economics and the observed facts (*i.e.* greater utilization of outsourced vis-à-vis utility labor and rising relative prices for utility labor) make it more reasonable to conclude that labor and non-labor opex PFP will also grow at different rates than it is to conclude the opposite, as Meyrick does. PEG therefore believes that a deeper analysis of the issues supports our original position and reveals that Meyrick's speculation is unfounded.

Meyrick also disputes PEG's conclusion that forecasts for the entire EGW sector are necessarily relevant for gas distribution. It writes that '(e)vidence discounting PEG's contention that the gas industry's experience may have been different to that of the broader EGW sector has recently been released in ABS (2007a). This shows that labour productivity of each of the three components of the EGW sector have followed a similar pattern over the last several years, with labour productivity generally declining."[22] Figure Three in Meyrick's Response then reproduces the ABS Electricity, Gas and Water Industry Labour Productivity Indexes from 1985-86 to 2005-06.

But, other than the fact the ABS measures of labor productivity have declined for electric, gas and water, Figure Three in Meyrick's Response does **not** show that "the three components of the EGW sector have followed a similar pattern over the last several years." Meyrick's own PFP research for the GDBs begins in 1998, so an apples-to-apples comparison between its analysis and that of the ABS would also begin in 1998. ABS does not provide the precise, labor PFP index numbers for each of the electric, gas and water components in the publication that Meyrick referenced, but one can still obtain a general measure of the relative PFP changes for each of these industry aggregations by looking at the positions of their trend lines in 1997-98 and 2005-06.[23] Figure Three shows that the water sector had a labor PFP index value of about 135 in 1998 and a labor PFP index value of about 100 in 2006. These index values are consistent with about a 26% decline in labor PFP for the water sector between 1998 and 2006 (*i.e.* (100-135)/135 = -26%). The analogous index values for electric are about 120 and 90, which translates into about a 25% decline in labor PFP. The labor PFP indexes for gas in these years are about 80 and 70, which is consistent with only about a 12.5% decline in labor PFP. Thus, even if we take Meyrick's evidence at face value, it does not support the conclusion that the entire EGW sector PFP is a good proxy for the PFP experience of Australia's gas industries; the trend rate of decline for electric and water industries are about two times as rapid as that for gas in recent years.[24]

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[22] Meyrick (2007a), p. 30.

[23] PEG has requested the actual PFP index values for the electric, gas and water components from the ABS but they were not provided.

[24] As a general matter, PEG also relieves that Meyrick's conclusions (both original and in its Response) place too much reliance on Figures as opposed to specific, numeric information to support its conclusions. Although this was unavoidable with respect to the ABS trends for the EGW sector, if data presented in figures are not presented and explained carefully, they can be more misleading than illuminating. We believe that is in fact the case with the ABS data that Meyrick presented in Figure Three. By contrast, analyses are much more transparent if all the quantitative evidence underlying a conclusion are presented in tabular format rather than in summary figures.

More importantly, as PEG originally noted, relying on the PFP experience of the entire EGW sector is inappropriate because this sector includes a wide range of disparate industries. The diversity of industries included in this sectoral aggregate becomes obvious when we consider what types of firms are grouped into the EGW sector. US data provide more information on this disaggregation than the ABS data sources, and below we replicate the entire list of six-digit NAICS codes and corresponding index entries that are bundled together into the US's analogous sector:[25]

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[25] The US Bureau of Labor Statistics (BLS) calculates labor productivity series for a very broad range of US industries. Although ABS provides a less detailed breakdown of the industries within the EGW sector, ABS descriptions show that the coverage in terms of basic industries is very similar across the countries. Below we reproduce ABS's description of detailed list of activities included in the Australian and New Zealand Standard Industrial Classification codes for the electric, gas, and water sector (Issue 1292.0, http://www.abs.gov.au/).

3610 Electricity Supply: This class consists of units mainly engaged in the generation, transmission or distribution of electricity. *Exclusions/References*: Units mainly engaged in the construction, repair or maintenance of electricity transmission towers or lines, power station buildings or water storage dams are included in Class 4122 Non-Building Construction. *Primary Activities*: Electricity distribution; Electricity generation; Electricity supply; Hydro-electric power generation; Sub-station operation (electricity supply).

3620 Gas Supply: This class consists of units mainly engaged in the manufacture of town gas from coal and/or petroleum or in the distribution of manufactured town gas, natural gas or liquefied petroleum gas through a system of mains, including pipelines operated on own account. *Exclusions/References*: Units mainly engaged in (a) treating natural gas to produce purified natural gas or liquefied hydrocarbon gases, or operating natural gas absorption or separation plants are included in Class 1200 Oil and Gas Extraction; (b) manufacturing liquefied petroleum gases in conjunction with petroleum refining are included in Class 2510 Petroleum Refining; (c) construction, repair or maintenance of gas mains are included in Class 4122 Non-Building Construction; (d) wholesaling or retailing liquefied petroleum gas in bottles or bulk (except through a mains system) are included in Class 4521 Petroleum Product Wholesaling; and (e) operating pipelines for the transport of gas on a contract or fee basis are included in Class 6501 Pipeline Transport. *Primary Activities*: Fuel gas distribution (through mains system); Gas, coal, distribution (through mains system); Gas, liquefied petroleum, distribution (through mains system); Gas, liquefied petroleum, reforming (for distribution through mains system); Gas, natural, distribution (through mains system); Town gas mfg and/or distribution through mains system (incl. mixtures of manufactured and town gas).

3701 Water Supply: This class consists of units mainly engaged in the storage, purification or distribution of water, by pipeline or carrier. It includes the operation of irrigation systems concerned with the supply of water to the farm, and the supply of steam or hot water. *Exclusion/References*: Units mainly engaged in (a) operating irrigation systems concerned with the distribution of water on the farm are included in Class 0219 Services to Agriculture; and (b) the construction or repair of water storage dams, mains or pumping stations are included in Class 4122 Non-Building Construction. *Primary Activities*: Dam operation (water supply); Desalination plant operation (water supply); Filtration plant operation (water supply); Mineral water supply (from the ground); Pumping station operation (water supply); Reservoir operation (water supply); Water supply system operation.

3702 Sewerage and Drainage Services: This class consists of units mainly engaged in operating sewerage or drainage systems or sewerage treatment plants. *Exclusions/References*: Units mainly engaged in the construction or repair of sewerage or stormwater drainage systems are included in Class 4122 Non-Building Construction. *Primary Activities*: Drainage system operation (town or stormwater); Pumping

221111 Hydroelectric Power Generation

- Electric power generation, hydroelectric
- Hydroelectric power generation
- Power generation, hydroelectric

221112 Fossil Fuel Electric Power Generation

- Electric power generation, fossil fuel (e.g., coal, oil, gas)
- Power generation, fossil fuel (e.g., coal, gas, oil), electric

221113 Nuclear Electric Power Generation

- Electric power generation, nuclear
- Power generation, nuclear electric

221119 Other Electric Power Generation

- Electric power generation, (except fossil fuel, hydroelectric, nuclear)
- Electric power generation, solar
- Electric power generation, tidal
- Electric power generation, wind
- Power generation, electric (except fossil fuel, hydroelectric, nonhazardous solid
- Power generation, solar electric
- Power generation, tidal electric
- Power generation, wind electric

221121 Electric Bulk Power Transmission and Control

- Electric power control
- Electric power transmission systems
- Transmission of electric power

221122 Electric Power Distribution

- Distribution of electric power
- Electric power brokers
- Electric power distribution systems

221210 Natural Gas Distribution

- Blue gas, carbureted, production and distribution
- Coke oven gas, production and distribution
- Distribution of manufactured gas
- Distribution of natural gas
- Gas, manufactured, production and distribution
- Gas, mixed natural and manufactured, production and distribution
- Gas, natural, distribution
- Liquefied petroleum gas (LPG) distribution through mains

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station operation (sewerage); Sewerage treatment plant operation; Sewerage system operation; Stormwater drainage system operation.

- Manufactured gas production and distribution
- Natural gas brokers
- Natural gas distribution systems
- Natural gas marketers

221310 Water Supply and Irrigation Systems

- Canal, irrigation
- Filtration plant, water
- Impounding reservoirs, irrigation
- Irrigation system operation
- Water distribution (except irrigation)
- Water distribution for irrigation
- Water filtration plant operation
- Water supply systems
- Water treatment and distribution
- Water treatment plants

221320 Sewage Treatment Facilities

- Collection, treatment, and disposal of waste through a sewer system
- Sewage disposal plants
- Sewage treatment plants or facilities
- Sewer systems
- Waste collection, treatment, and disposal through a sewer system

221330 Steam and Air-Conditioning Supply

- Air-conditioning supply
- Cooled air distribution
- Distribution of cooled air
- Distribution of heated air
- Distribution of steam heat
- Geothermal steam production
- Heat, steam, distribution
- Heated air distribution
- Heating steam (suppliers of heat) providers
- Steam heat distribution
- Steam heating systems (i.e., suppliers of heat)
- Steam production and distribution
- Steam supply systems, including geothermal

Now, PEG concedes that not all these industries may be as prominent in Australia as in the US; indeed, some (such as nuclear power generation) do not exist at all. Nevertheless, we believe most observers will accept that most of the activities listed above also exist to at least some extent in Australia and are therefore captured in the ABS measure of EGW labor productivity. It can also be seen that this sector goes *well* beyond gas distribution, which is the focus of the GAAR, and features industries operating under a wide array of technological and output growth conditions. PEG has examined public and private data sources which show that *at least* 94% of the output in Australia's EGW sector is for activities other than gas distribution, and the actual share of gas distribution to output in this sector is probably closer to 2%.[26] Meyrick therefore recommends that gas distribution opex PFP be forecast using a sectoral aggregate in which gas distribution plays a very minor role and which is, instead, dominated by a plethora of industries as diverse as solar power generation, canal irrigation and sewage disposal. PEG believes that this is insupportable. It is also immaterial that ABS "staunchly defends their results" related to PFP measurement for the entire EGW sector; this sector includes a wide range of businesses and activities that are simply irrelevant to the GAAR, and looking to the PFP experience of wind power generators, water filtration plants, and coke oven gas producers would neither constitute "a reasonable basis" nor lead to "best estimates" for gas distribution opex PFP trends.

Relatedly, Meyrick says that the "finding(s) from Australia's national statistics office cannot simply be ignored when considering what opex partial productivity forecast is appropriate for the Victorian GDBs."[27] But this statement misrepresents PEG's work. We did not ignore these results; we carefully examined them on a historical basis and found them inappropriate for the Victorian GDBs. This is evident in the following passage from PEG's original report:

> Further evidence for this view (that EGW opex PFP is relevant for the GDBs) comes from a historical comparison of the BIS and Meyrick productivity estimates. The BIS productivity growth measures for the utilities sector appear in Table 5.2 of BIS (2007a). Below we compare the BIS and Meyrick estimates of PFP change over the 1998-2006 period:

	Opex PFP Change Meyrick	Labor PFP Change BIS Shrapnel
1999	10.82%	1.0%

[26] Because these calculations draw on confidential as well as public data sources, they cannot be revealed in this document, but PEG is of course willing to make these data and our computations available for scrutiny by other parties who are willing to keep these data confidential.

[27] Meyrick (2007a), p. 31.

2000	8.53%	2.9%
2001	4.21%	-0.2%
2002	-0.87%	-3.6%
2003	3.73%	-6.4%
2004	3.96%	-2.7%
2005	12.02%	-1.3%
2006	8.87%	-10.8%

> There is little, or no, relationship between these historical PFP growth rates. If anything, the divergence between the Meyrick and BIS PFP estimates has become more pronounced in recent years. BIS Shrapnel has measured dramatic PFP declines in each of the last six years, while Meyrick has measured accelerating PFP growth for the GDBs over the same period. As discussed, we believe the Meyrick opex PFP estimates are generally sound, although Meyrick's measured PFP growth rates would be even higher if they used the AWOTE for the EGW sector as a price deflator. Much less detail is presented on the computation of the BIS Shrapnel PFP measures, but PEG believes they are radically different than Meyrick's primarily because they are measured for a different and expanded set of utility services.
>
> PEG concludes that the BIS Shrapnel forecasts do not satisfy the historical consistency criterion established in Chapter Two. Meyrick has developed a generally reliable measure of historical PFP trends for Victoria's GDBs. The BIS Shrapnel PFP estimates bear little or no relationship to these generally reliable estimates over the same historical period. Because the BIS PFP trends have little or no historical correlation with the GDBs' past opex PFP experience, there is little reason to believe the BIS projections will be consistent with the GDBs' future PFP experience over the term of the GAA. We therefore conclude that the BIS Shrapnel forecasts are not "best estimates" of opex PFP growth, as required by the Gas Code. [28]

This passage contains the core of PEG's analysis regarding the use of BIS Shrapnel forecasts for setting opex PFP trends for the GDBs. Meyrick's statement that we "ignore" the ABS PFP results does not fairly or accurately summarize our work on this issue. Meyrick's Response also never disputes or even addresses our analysis above, which we therefore believe continues to hold. Indeed, PEG believes that if the premise is accepted (*i.e.* there is little, or no, relationship between the GDB and ABS historical PFP growth rates), the logic that follows is transparent and leads inevitably to the conclusion that "because the BIS PFP trends have little or no historical correlation with the GDBs'

[28] Kaufmann (2007a), *op cit*, pp. 46-47. Note that the BIS historical PFP data referred to in this passage are computed by ABS for the EGW sector.

past opex PFP experience, there is little reason to believe the BIS projections will be consistent with the GDBs' future PFP experience over the term of the GAA." PEG therefore concludes that the BIS PFP projections for the EGW sector do not provide a reliable basis for projecting the GDBs' opex PFP growth.

Meyrick's Response also makes a new claim and says that labor PFP growth for the *entire* Australian economy may be a good proxy for the GDBs opex PFP growth. It writes that "(a)ssuming the Victorian GDBs are operating efficiently – a reasonable assumption after 10 years of privatisation and incentive regulation and consistent with the findings of quantitative benchmarking studies – then the economy-wide rate of labour productivity growth is likely to form the upper bound for reasonable forecasts of GDB labour productivity growth and GDB productivity performance is likely to be less than this."[29]

There is simply no logical or factual basis for this claim. The Australian economy is filled with profit-oriented businesses with strong incentives to operate efficiently, and yet the PFP trends for these businesses often diverge significantly from economy-wide PFP trends. This is also true for the US economy and other advanced industrial economies. These facts are clearly demonstrated in the tables that appear below.

[29] Meyrick (2007a), p. 31.

Table 1

Australian Labor PFP in Disaggregated Industries

Industry	Labor Productivity Index[1] 1998-1999	1999-2000	2000-2001	2001-2002	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	Average Growth 1998-2005	Average Growth 1998-2007
Agriculture, Forestry, Fishing	66.2	66.1	71.3	72.4	65.8	85.8	92.3	100.0	73.5	5.54%	1.31%
Mining	125.3	141.3	155.2	155.5	140.0	123.7	118.7	100.0	101.2	-0.90%	-2.67%
Manufacturing	85.2	85.9	90.1	95.5	94.7	99.8	97.4	100.0	102.9	2.23%	2.36%
Electricity, Gas, & Water Supply	127.5	131.8	127.8	120.5	117.0	111.4	109.2	100.0	98.8	-2.58%	-3.19%
Construction	94.3	90.4	82.0	90.2	100.0	97.2	96.5	100.0	100.2	0.38%	0.76%
Wholesale Trade	77.6	77.9	82.6	85.8	87.9	91.3	96.9	100.0	95.1	3.70%	2.54%
Retail Trade	88.4	88.3	91.7	93.2	93.6	97.6	98.3	100.0	104.6	1.77%	2.10%
Accommodation, Cafes, Restaurants	88.5	86.0	83.8	89.1	92.8	93.6	93.5	100.0	98.4	0.92%	1.33%
Transport & Storage	81.0	83.6	85.2	91.4	97.6	95.5	98.0	100.0	104.1	3.18%	3.14%
Communication Services	82.1	78.2	75.9	86.0	90.8	95.1	91.3	100.0	106.1	1.77%	3.21%
Finance & Insurance	87.3	91.5	91.3	92.5	93.8	97.9	99.1	100.0	100.1	2.11%	1.71%
Health & Community Services	91.2	94.7	94.3	96.8	98.8	100.4	101.0	100.0	99.9	1.70%	1.14%
Cultural & Recreational Services	91.6	91.7	98.8	95.6	95.1	104.0	102.3	100.0	104.9	1.84%	1.69%
Market sector	87.5	87.5	89.3	92.9	94.5	97.3	97.6	100.0	100.4	1.82%	1.72%
All industries	89.9	90.5	91.9	95.7	96.2	98.3	98.8	100.0	100.7	1.57%	1.42%

[1] *Source*: ABS. "Labor Productivity: Gross value added per hour worked - By industry," Australian System of National Accounts, 5204.0, 2006-07 (pp. 43-45)

Table 2

Australian Labor PFP in Disaggregated Industries

Industry	Average Growth 1998-2005	Industry PFP - Australia PFP Differential Total
Agriculture, Forestry, Fishing	5.54%	3.72%
Mining	-0.90%	-2.72%
Manufacturing	2.23%	0.41%
Electricity, Gas, & Water Supply	-2.58%	-4.40%
Construction	0.38%	-1.44%
Wholesale Trade	3.70%	1.88%
Retail Trade	1.77%	-0.05%
Accommodation, Cafes, Restaurants	0.92%	-0.90%
Transport & Storage	3.18%	1.35%
Communication Services	1.77%	-0.05%
Finance & Insurance	2.11%	0.29%
Health & Community Services	1.70%	-0.12%
Cultural & Recreational Services	1.84%	0.02%
Range	-2.6% to 5.5%	-4.4% to 3.7%

Table 3

US Labor PFP in Disaggregated (3-digit NAICS code) Industries

Industry	NAICS code	Labor Productivity Index[1] 1998	1999	2000	2001	2002	2003	2004	2005	Average Growth 1998-2005
Oil and gas extraction	211	101.22	107.93	119.44	121.63	123.83	130.12	111.70	107.87	0.91%
Mining (except oil and gas)	212	104.55	105.79	106.35	109.03	110.98	113.60	115.66	113.46	1.17%
Food manufacturing	311	103.94	105.93	107.10	109.54	113.84	116.83	117.30	123.75	2.49%
Beverage & tobacco product manufacturing	312	97.65	87.31	88.33	89.51	82.56	90.93	94.69	100.01	0.34%
Textile mills	313	102.62	106.19	106.71	109.46	125.30	136.06	138.58	147.77	5.21%
Textile product mills	314	98.73	102.51	107.10	104.53	107.32	112.74	123.38	134.25	4.39%
Apparel manufacturing	315	101.85	111.75	116.78	116.54	102.87	112.43	103.47	111.34	1.27%
Leather and allied product manufacturing	316	106.62	112.74	120.32	122.39	97.69	99.81	109.52	120.24	1.72%
Wood product manufacturing	321	101.23	102.93	102.74	106.12	113.59	114.70	115.58	123.07	2.79%
Paper manufacturing	322	102.32	104.10	106.27	106.84	114.17	118.91	123.40	125.28	2.89%
Printing and related support activities	323	100.56	102.82	104.58	105.31	110.22	111.06	114.52	119.71	2.49%
Petroleum and coal products manufacturing	324	102.25	107.09	113.49	112.11	118.04	119.19	123.41	123.76	2.73%
Chemical manufacturing	325	99.86	103.55	106.56	105.32	114.19	118.35	125.78	132.65	4.06%
Plastics and rubber products manufacturing	326	103.20	107.94	110.21	112.30	120.80	126.03	128.71	132.73	3.59%
Nonmetallic mineral product manufacturing	327	103.68	104.30	102.53	99.99	104.59	111.14	108.69	114.59	1.43%
Primary metal manufacturing	331	102.03	102.75	101.32	100.99	115.16	118.19	131.93	134.35	3.93%
Fabricated metal product manufacturing	332	101.26	102.99	104.79	104.85	110.91	114.44	113.38	116.28	1.98%
Machinery manufacturing	333	102.82	104.68	111.42	108.95	116.53	125.18	127.04	133.76	3.76%
Computer and electronic product manufacturing	334	118.39	149.45	181.79	181.51	188.13	217.81	244.74	259.91	11.23%
Electrical equipment, appliance, component manufacturing	335	103.93	106.55	111.53	111.41	113.35	117.14	123.36	129.95	3.19%
Transportation equipment manufacturing	336	109.84	117.90	109.18	113.69	127.36	137.50	134.81	140.28	3.49%
Furniture and related product manufacturing	337	102.03	101.57	101.43	103.36	112.61	116.98	118.55	125.22	2.93%
Miscellaneous manufacturing	339	105.10	107.55	114.26	115.98	123.30	131.79	133.95	145.09	4.61%
Merchant wholesalers, durable goods	423	107.07	119.20	125.08	128.99	140.21	146.68	161.51	167.28	6.37%
Merchant wholesalers, nondurable goods	424	99.06	100.85	105.07	105.08	105.78	110.50	113.60	114.34	2.05%
Wholesale electronic markets & agents & brokers	425	102.43	112.35	120.14	110.74	109.78	104.11	96.97	87.27	-2.29%
Motor vehicle and parts dealers	441	106.42	115.14	114.26	115.98	119.94	124.26	127.32	127.03	2.53%
Furniture and home furnishings stores	442	104.10	110.82	115.94	122.42	129.26	134.60	146.73	151.38	5.35%
Electronics and appliance stores	443	122.62	150.58	173.73	196.71	233.53	292.66	334.13	369.57	15.76%
Building material & garden equipment & supplies dealers	444	107.42	113.78	113.27	116.85	120.83	127.11	134.52	134.87	3.25%
Food and beverage stores	445	99.90	101.89	101.03	103.80	104.73	107.18	112.85	118.31	2.42%
Health and personal care stores	446	103.99	107.05	112.19	116.24	122.94	129.45	134.28	133.23	3.54%
Gasoline stations	447	106.65	110.71	107.74	112.90	125.10	119.91	122.19	124.57	2.22%
Clothing and clothing accessories stores	448	106.32	114.00	123.48	126.37	131.25	138.88	139.09	147.85	4.71%
Sporting goods, hobby, book, & music stores	451	107.92	114.02	121.11	127.11	127.57	131.52	151.10	164.82	6.05%
General merchandise stores	452	105.29	113.44	120.17	124.77	129.10	136.90	140.67	144.96	4.57%
Miscellaneous store retailers	453	108.89	111.29	114.11	112.63	119.12	126.15	130.76	141.99	3.79%
Nonstore retailers	454	114.33	128.92	152.17	163.65	182.07	195.48	215.49	218.43	9.25%
Air transportation	481	97.59	98.24	98.11	91.90	102.12	112.70	126.02	135.71	4.71%
Postal service	491	101.64	102.78	105.46	106.27	106.44	107.85	110.04	111.20	1.28%
Couriers and messengers	492	112.57	117.65	121.95	123.42	131.09	134.12	126.86	124.67	1.46%
Publishing industries (except internet)	511	116.11	116.26	117.06	116.56	117.19	126.37	130.75	136.17	2.28%
Food services and drinking places	722	100.97	100.90	103.46	103.77	104.40	106.31	106.98	108.21	0.99%
U.S. Private Non-Farm Business Sector		110.30	113.94	116.28	117.60	122.17	126.12	129.58	131.85	2.55%

[1] *Source* : U.S. Bureau of Labor Statistics, Labor productivity (output per hour)

Table 4

US Labor PFP[1] in Disaggregated (3-digit NAICS code) Industries

Industry	Average Growth 1998-2005	Industry PFP - US PFP Differential Total
Oil and gas extraction	0.91%	-1.64%
Mining (except oil and gas)	1.17%	-1.38%
Food manufacturing	2.49%	-0.06%
Beverage & tobacco product manufacturing	0.34%	-2.21%
Textile mills	5.21%	2.66%
Textile product mills	4.39%	1.84%
Apparel manufacturing	1.27%	-1.28%
Leather and allied product manufacturing	1.72%	-0.83%
Wood product manufacturing	2.79%	0.24%
Paper manufacturing	2.89%	0.34%
Printing and related support activities	2.49%	-0.06%
Petroleum and coal products manufacturing	2.73%	0.18%
Chemical manufacturing	4.06%	1.51%
Plastics and rubber products manufacturing	3.59%	1.05%
Nonmetallic mineral product manufacturing	1.43%	-1.12%
Primary metal manufacturing	3.93%	1.38%
Fabricated metal product manufacturing	1.98%	-0.57%
Machinery manufacturing	3.76%	1.21%
Computer and electronic product manufacturing	11.23%	8.68%
Electrical equipment, appliance, component manufacturing	3.19%	0.64%
Transportation equipment manufacturing	3.49%	0.95%
Furniture and related product manufacturing	2.93%	0.38%
Miscellaneous manufacturing	4.61%	2.06%
Merchant wholesalers, durable goods	6.37%	3.83%
Merchant wholesalers, nondurable goods	2.05%	-0.50%
Wholesale electronic markets & agents & brokers	-2.29%	-4.84%
Motor vehicle and parts dealers	2.53%	-0.02%
Furniture and home furnishings stores	5.35%	2.80%
Electronics and appliance stores	15.76%	13.21%
Building material & garden equipment & supplies dealers	3.25%	0.70%
Food and beverage stores	2.42%	-0.13%
Health and personal care stores	3.54%	0.99%
Gasoline stations	2.22%	-0.33%
Clothing and clothing accessories stores	4.71%	2.16%
Sporting goods, hobby, book, & music stores	6.05%	3.50%
General merchandise stores	4.57%	2.02%
Miscellaneous store retailers	3.79%	1.24%
Nonstore retailers	9.25%	6.70%
Air transportation	4.71%	2.16%
Postal service	1.28%	-1.27%
Couriers and messengers	1.46%	-1.09%
Publishing industries (except internet)	2.28%	-0.27%
Food services and drinking places	0.99%	-1.56%
Range	-2.3% to 15.8%	-4.8% to 13.2%

[1] *Source* : U.S. Bureau of Labor Statistics, Labor productivity (output per hour)

The first two of these tables present data on labor PFP growth for different sectors of the Australian economy as well as the overall market sector and all Australian industries. The PFP trend for Australia's market sector is most relevant to Meyrick's discussion of profit-oriented businesses with strong incentives to operate efficiently. Labor PFP for Australia's market sector grew at an average annual rate of 1.8% over the 1998-2005 period (which we have chosen to allow comparability to the US results). Over the same period, the average PFP trends for major sectors ranged from -2.6% for the electric, gas and water industries to 5.5% for agriculture, forestry and fishing. On a relative basis, PFP for the most rapidly growing sector was more than 300% greater than for the market sector as a whole.

The next two tables present data on labor PFP growth for different sectors of the US economy. Data are available for more disaggregated industry sectors in the US, although some of these PFP measures have not been computed past 2005. The US data show that labor PFP growth for the US private, non-farm business sector grew by 2.55% over the 1998-2005 period. Labor PFP growth over this period ranged from a high of 15.8% for electronics and appliance stores to -2.3% for wholesale electronic markets, agents and brokers. In addition to showing that there is a wide diversity in labor PFP trends among industries, the divergences between the PFP experience of the wholesaling and retailing of electronic goods and appliances also demonstrates the dangers of assuming that industries that may appear to be similar (such as power and electricity distribution, or the wholesaling and retailing of electronic goods) will necessarily have similar PFP trends.

Data from the US and Australia clearly show that PFP growth for privatized, profit-oriented businesses can differ significantly from overall PFP trends, and there is no reason to expect that labor PFP trends for different industries will necessarily "converge" to economy-wide PFP trends. This is not surprising, because technological, market and output growth conditions vary widely across industries, and all of these factors can impact PFP growth. There are also good reasons to believe that GDBs' PFP growth would exceed economy-wide PFP trends for significant periods of time. Most importantly, gas distribution is more capital intensive than the overall economy, and the potential to achieve economies of scale in gas distribution greatly exceeds that of most other economic sectors. Indeed, the main reason that gas distribution services are typically provided by regulated monopolies (for assigned service territories) is that gas distributors are "natural monopolies" whose technologies are characterized by extensive economies of scale. The ability of GDBs to realize greater scale economies, compared to nearly every other economic enterprise, is just one reason why gas distributors' opex PFP growth can be expected to differ from the economy-wide opex PFP growth.

Finally, if the economy-wide PFP trend is good enough for setting the terms of the rate of change formula, one wonders why Meyrick went through all the trouble of estimating gas distribution PFP or preparing a detailed PFP recommendation. It would be far easier just to take the existing, publicly available ABS estimate of economy-wide PFP trends and use this as a proxy for achievable PFP gains. PEG believes that such an approach is clearly untenable, and it demonstrates the flaws of attempting to infer GDBs' PFP growth using broad aggregations of dissimilar industries. Estimates of gas distribution opex PFP should be developed using data from the gas distribution industry only. Mixing data from other industries into these computations is likely to distort the calculated trend and will certainly lead to departures from "best estimates determined on a reasonable basis."

3.3.3 North American PFP Experience and Regulatory Precedents

Meyrick's original report claimed that its PFP recommendation was supported by the productivity experience of North American GDBs. PEG corrected the record and stated that "Meyrick's data on this issue are simply not accurate…Public documents from the sources and jurisdictions that Meyrick cites show that accurate opex PFP trends for the North American gas distribution industry are in the range of 2% and higher."[30] It is very unfortunate that Meyrick's Response has disregarded this factual record and attempted to cherry pick the available evidence in an attempt to defend its preconceived recommendation. Meyrick is entitled to its opinion, but it is not entitled to its facts, and the facts remain very much the opposite of what Meyrick claims. Precedents from North American regulators do not support a 0.8% opex PFP trend for gas distributors.

[30] Kaufmann (2007a), p. 47-48.

It should not be forgotten that Meyrick's original paper attempted to use information on *TFP* trends from North American regulatory precedents to support its recommendation for opex *PFP* growth. Page 13 of Meyrick (2007b) says that "North American gas distribution decisions have generally included relatively low acknowledged productivity trends reflecting the more mature nature of the North American industry."[31] It then cites the "productivity" trends approved for Boston Gas (in 1997 and 2003), Berkshire Gas, San Diego Gas and Electric, Southern California Gas, and Consumers Gas and Union Gas in Ontario as evidence of "low" productivity trends. But of these seven cited precedents, six refer to TFP (*i.e.* that include capital and opex inputs) rather than opex PFP trends.[32]

This is not a small mistake. TFP and PFP are different concepts, and no regulator should be misled into thinking that they are the same or that TFP precedents have any necessary relevance for appropriate PFP trends. TFP and opex PFP trends can be and usually are very different for gas distributors. Meyrick's original report obfuscated the difference between TFP and opex PFP trends and attempted to pass off the former in discussions of appropriate values for the latter. While this error may have been unintentional, it is clearly detrimental to the objective of choosing appropriate parameters for the rate of change formula.[33] An objective Response to PEG's report should at least have acknowledged that Meyrick (2007b) contained serious factual errors regarding North American regulatory precedents and may have inadvertently misled the ESC on this issue.

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[31] Meyrick (2007b), p. 13.

[32] The one exception is for Consumers (now Enbridge) Gas, whose 0.63% PFP trend was based on its own experience and was not an industry PFP measure. Moreover, as anyone who is familiar with the Ontario gas distribution industry knows, the PBR plan that embodied this PFP trend was a dramatic and unambiguous failure. This view is shared universally by the company, the Ontario Energy Board and its Staff, and by customer groups; PEG would be willing to provide contact information to individuals at all the relevant institutions for anyone that wishes to confirm that this was the case or to learn more about this plan. While the value for the PFP trend was not the only reason for the failure of the plan, no knowledgeable analyst would cite the Consumers PBR plan as a valuable precedent for other regulators to emulate.

[33] That is, reasonable parties cannot disagree that the opex rate of change formula should be calibrated using information on opex PFP growth rather than TFP growth. Regardless of the value chosen for the formula, using TFP growth to calibrate the formula is clearly unwarranted and detrimental to forecasting opex using "best estimates determined on a reasonable basis."

PEG's original report presented accurate information on PFP growth from Massachusetts and Ontario, two of the three North American jurisdictions that Meyrick originally cited. PEG noted that opex PFP growth in the Boston Gas (2003) proceeding was 2.45%; Meyrick ignored this evidence, which clearly demonstrates that its opinion of a 0.8% PFP trend from the US is erroneous. PEG's research in Ontario was for the 1994 to 2004 period and estimated opex PFP growth of between 2.14% and 2.23%. It should be noted that PEG has recently updated its report in Ontario, and these results show that opex PFP for US gas distributors grew between 2.36% and 2.41% per annum over the 1994-2004 period. TFP growth for US GDBs grew between 1.40% and 1.61% over this period.[34]

In assessing the results from the previous Ontario report, Meyrick wrote that "within this period, however, there are two very distinct patterns of productivity growth with a break point around 1999…it is the more recent period since 1999 which is more directly comparable with the time period of current GDB operation in Victoria. Including results from the last century distorts assessments of the likely opex partial productivity improvements achievable in the next GAA."[35]

These statements reveal a lack of understanding of the North American gas distribution industry and the drivers of its PFP growth. Meyrick could hardly have selected a less representative recent period for estimating the US gas distribution industry's TFP growth than 1999-2004. There are sound reasons why the data reveal a "break point" in PFP beginning in that year, but they reflect short-term circumstances rather than long-term trends. One issue is that the US economic expansion effectively peaked in 1999 before slowing considerably in 2000 and then dipping into recession in 2001.[36] Meyrick's arbitrary start date of 1999 is therefore measuring PFP growth at the peak of a business cycle, and its short sample period includes several years of recession and relatively slow growth. It is widely accepted that output growth, and PFP, will decline in recession years, and a PFP (or TFP) trend that is not measured at comparable

[34] M. Lowry *et al* (2007), "Rate Adjustment Indexes for Ontario's Natural Gas Utilities," Report to the Ontario Energy Board, 20 November 2007.

[35] Meyrick (2007a), p. 33.

[36] The US economy grew rapidly in 1999, slowed significantly in the first half of 2000, and then declined in the third quarter of 2000. Data on quarterly changes in US GDP over this period can be found at http://www.bea.gov/national/xls/gdplev.xls.

points in the business cycle (*e.g.* peak to peak) can lead to distorted estimates of the long-run PFP (or TFP) trends. Meyrick is in fact picking up those declines in economic activity, and corresponding slower growth in gas distribution output, but these transitory influences represent a distortion of the long-run PFP growth trend and not an accurate measure of it.

At least as importantly, the period after 1999 in the US was one of rapid and significant increases in gas commodity prices. These higher gas commodity prices also tended to depress natural gas consumption and therefore measured gas distribution output.[37] In addition, higher gas commodity bills caused many gas distributors to incur higher expenses for bill collection and write offs of unpaid bills, which tended to raise gas distribution costs. Both of these factors are specific to the gas distribution industry and would be reflected in lower PFP growth.

The pattern of many gas distributors' pension contributions also changed after 1999 in a way that tended to increase measured labor input quantity and, therefore, reduced opex PFP growth. The long stock market boom of the 1990s came to an end just after 1999. Many distributors conserved on pension contributions during the mid-to late 1990s since the increase in equity markets during these years made it easier for utilities to meet their pension obligations with fewer cash contributions. However, there were dramatic declines in equity markets in 2000 through 2002, particularly after the September 11 attacks. These losses led to greater unfunded pension liabilities for many utilities, which required greater contributions to pension funds. These contributions were booked as labor expenses but not matched by corresponding growth in the labor price indexes that were used to deflate labor expenditures and thus convert them to labor input quantities. Accordingly, the ramp up in pension contributions after 1999 led to greater growth in labor input quantity and, all else equal, lower opex PFP growth.[38]

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[37] A recent discussion of the impact of gas prices on US natural gas consumption can be found in Joutz and Trost (2007).

[38] Gas PFP trends can be also be particularly impacted by the severity of winter weather in a given year. If the start date for measuring PFP trends corresponds to an especially cold winter, gas delivery volumes will be unusually high in that year and, all else equal, measured changes in output and PFP will be artificially low. The converse is also true. PEG carefully examines the start and end dates for our TFP and PFP analyses to ensure that they are not distorted by weather effects, which is another factor that Meyrick ignored.

In short, Meyrick's conclusion that US gas distribution PFP trends for 1999-2004 represent "likely opex partial productivity improvements achievable in the GAA" is no more tenable than if the Victorian GDBs' 6% annual PFP growth since 1998 was applied in US PBR plans. In both cases, the sample period is impacted by transitory experiences that distort the measured trend compared with long-run, achievable PFP growth. The US gas distribution opex PFP trend in 1999-2004 was damped by slowing economic growth, a dramatic increase in gas commodity prices, and macroeconomic shocks that increased unfunded pension liabilities. No evidence has been presented that these factors are expected to prevail for Victoria's gas distributors over the term of the GAA. Meyrick's conclusion also illustrates the dangers of relying on specious studies from different industries (either utility industries providing different services or operating in different jurisdictions) and assuming that such studies are appropriate for determining appropriate PFP trends for Victoria's GDBs.[39]

In addition to distorting the measured PFP trend, Meyrick's attempt to cherry pick a five year sample period runs directly counter to precedents in North America. North American regulators are well aware that short time periods, such as five years, do not necessarily reflect long-term TFP (or PFP) trends well. Short time periods can be distorted by output fluctuations or the timing of certain expenditures (*e.g* pension contributions) that tend to balance out over longer periods. PBR precedents therefore usually use 10 years or more of information to measure productivity, as PEG had done in its Ontario study (as well as our other studies). Recall that Meyrick's entire discussion of the North American experience pertains to "North American precedents" and what they imply for appropriate values of PFP growth. No North American regulator has ever set the terms of a GDB indexing plan using only five years of TFP (or PFP) rate of change information, as Meyrick (2007b) is advocating. Meyrick's *ad hoc* analysis therefore cannot be represented as a "regulatory precedent" for gas distributors, and if such cherry

[39] It should also be noted that, in the Ontario study that Meyrick examined, output quantity growth is about 1% per annum, whereas output quantity growth is closer to 2% per annum in Victoria. This difference is due to the greater maturity of the US industry and was partly explained in PEG's original report. However, it is directly relevant to opex PFP comparisons between the jurisdictions. Opex PFP growth is equal to output quantity growth minus the growth in opex quantity. Output growth in the US is about 1% slower than output quantity growth in Victoria; all else equal, this implies that PFP growth in the US would be 1% lower than in Victoria. Hence, the observed opex PFP growth rates of 2% or more in US are conservative and, indeed, are too low, for the more rapidly growing Victorian market.

picking of the start and end dates of PFP studies was ever put forth in a North American regulatory proceeding it would almost certainly be rejected.

It is also instructive to compare Meyrick's claim of 0.8% opex PFP growth for US gas distributors with official measures of labor productivity growth for the US gas distribution industry. The US Bureau of Labor Statistics (BLS) estimates labor productivity growth for numerous sectors of the US economy, including the gas distribution industry and the electric power sector (generation, transmission and distribution). For the 1998-2005 period (the most comparable period to the 1998-2006 PFP trends computed by Meyrick), BLS estimates that labor productivity growth for the US gas distribution industry grew by 3.16% per annum. The comparable figure for the electric power sector was 1.37%.[40] PEG believes these figures are not as accurate as our estimates of opex PFP growth for the reasons previously discussed (*e.g.* changes in the mix of labor and non-labor opex inputs, aggregation of industries). Nevertheless, these trends provide independent, third party information supporting the view that opex PFP growth for US gas distributors is well above 0.8% per annum. It also provides further corroboration that opex PFP for gas and electric utilities can grow at very different rates and only the former should be used to calibrate GDBs' opex rate of change formulas.

Finally, it should be noted that Meyrick puts forth a purported estimate of opex PFP trends for US GDBs using Platts and other data. It concludes that this analysis leads to an estimate of opex PFP trends of 0.24% for a smaller, balanced panel of US companies and 0.68% for a larger unbalanced panel, both for the 1998-2005 period. It claims that these estimates are similar to what PEG presented in Ontario.

There are manifold errors with the opex PFP estimates that Meyrick presents for US GDBs, but most profoundly this work cannot even be fairly described as "evidence." Meyrick's description of its US PFP work is thin and unsubstantiated, and its PFP

[40] These data can be obtained through the following search. First, go to the BLS labor productivity homepage at http://www.bls.gov/lpc/home.htm , then execute the following series of commands/links within this page: 1) Get Detailed Productivity and Costs Statistics; 2) Create Customized Tables (one screen); 3) in section 2, choose "N2211_ Electric power generation, transmission, and distribution" and "N2212_ Natural gas distribution"; 4) in section 3, choose "Labor productivity, output per hour"; 5) in section 4, "index, 1997=100"; 6) Get Data.

estimates appear *dues ex machina.* There are no tables showing its results or the details of its analysis – it does not even say what companies are included in its samples. PEG believes that if Meyrick was advising a regulator, it would give no credence to such a slim, unsupported study by another firm, and it should apply the same standards to its own work. It is also notable that this purports to be an estimate of the opex PFP trends for US GDBs. PEG has more experience than any other consultant testifying on energy productivity in US regulation, and we can say with confidence that the PFP trend estimate presented in Meyrick (2007a) would not be considered a best estimate determined on a reasonable basis in any US performance-based regulation proceeding.

But although Meyrick provides little support for its purported estimate, it does provide enough detail to show that its PFP estimates are both inaccurate and not appropriate for the GAAR. One fatal flaw is that Meyrick's opex measure does not include administrative and general (A&G) expenses. These are an important component of any gas distributor's operating expenses. A&G expenses are also included in the GDB opex that is adjusted by the rate of change formula, of which the PFP trend is a component. Any measure of gas distributors' opex PFP that does not include A&G expenses is therefore inaccurate and internally consistent with the costs to which the rate of change formula is applied.

Meyrick's other work in the GAAR also raises serious concerns about any estimates it puts forward using US gas distribution data. In a benchmarking report for Multinet, Meyrick mistakenly believed that it was not possible to obtain measures of GDBs' distribution opex that were independent from their gas purchase costs and developed a proxy for each distributor's gas purchase prices using state level data on "city gate" gas prices (*i.e.* the price of the gas commodity and transmission services to distribution facilities). Each GDB's gas purchase costs do exist, however, and in our review of Meyrick's benchmarking work, PEG compared these actual gas purchase costs with Meyrick's proxy costs. This comparison showed that Meyrick's proxies were inaccurate and led to errors (either under-estimates or over-estimates) in GDB opex by 60%, *on average*.[41] Astonishingly, Meyrick continued to defend its proxies on the grounds that these errors more or less balanced out among US companies so that the

[41] Kaufmann (2007b), pp. 16-22.

proxy was correct on average.[42] This is akin to saying that if an airline flying from San Francisco to Sydney sends half its planes into the Coral Sea 1000 miles due north of Sydney and the other half into the Tasman Sea 1000 miles due south, every plane is arriving safely at its destination. Meyrick's refusal to use actual US opex data in place of demonstrably inaccurate proxies eviscerates the credibility of its US opex benchmarking work.[43] While Meyrick does not provide enough evidence to determine whether those same proxies are being used for its opex PFP measures, the work it has presented in the GAAR seriously undermines confidence in its ability to interpret or apply the US GDB data properly.[44]

3.3.4 Australian Precedents

Finally, Meyrick says its PFP recommendation is supported by regulatory precedents for energy distributors in Australia. However, every precedent that Meyrick cites is for power distribution and not gas distribution and, for reasons that PEG discussed in its original report and which have been elaborated here, we do not believe that PFP information from outside the gas distribution industry is not relevant to the GDBs' particular business conditions.

Meyrick's Response maintains that precedents from US electricity DBs are relevant for determining appropriate PFP trends for Victorian GDBs. It also believes that PEG's original report contains statements that support this view. Meyrick (2007a, p.32) states that

> PEG (2007a, p. 43) itself recognizes how similar one would expect the productivity performances of gas and electricity distribution businesses to be:
>
> > A third possibility is that the long-run opex PFP trend is greater fro the GDBs than the power distributors. While this is possible, it seems a highly unlikely explanation for differences in the industry's patterns of PFP gains. There is little reason to believe that the acceleration in GDBs' opex PFP over the 2002-06 period reflects differences in the industry's long-run sustainable behavior.

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[42] Meyrick (2007d), p. 8.

[43] Even if they were less inaccurate, there is no valid reason to use proxy data in place of real data when the latter exist, as they do for US operating expenditures.

[44] Identifying the correct data series in Platts is a relatively minor part of using US gas distribution data correctly. Other data quality controls require more detailed knowledge of industry developments than can be obtained through off-the-shelf databases.

> This is clearly inconsistent with PEG's subsequent claim that electricity distribution opex partial productivity information is of no relevance to forecasting likely GDB performance and, does, in fact, support the use of electricity distribution information as well as gas distribution information in Meyrick (2007a).

In fact, there is no inconsistency in PEG's position on these issues, as a careful reading of the passage Meyrick cites reveals. PEG is referring to differences in the *acceleration* of PFP between gas and electric distributors. That fact is clear in the last sentence Meyrick cites. Acceleration refers to an *increase in the rate of change* of PFP, not the rate of change itself (for the mathematically inclined, the rate of change of PFP would refer to the first derivative of PFP with respect to time; acceleration refers to the second derivative of PFP with respect to time). The point that is being made in the three sentences that Meyrick cites is that there is little reason to think that, compared with electricity distributors, the fundamental drivers of PFP growth for gas distributors would lead to an acceleration of PFP growth for GDBs over time. Even more precisely, this passage says there is no reason to believe that as the amount of time since privatization increases, the fundamental PFP drivers would lead the opex PFP trend for Victoria's GDBs to accelerate when the opposite was the case for Victoria's electricity distributors.

These points become clearer when we recall the context in which those sentences appear. This passage appears in an analysis of one of Meyrick's findings with respect to GDB PFP growth – namely, that the GDBs' PFP growth was greater in 2002-2006 than it was in 1998-2002. This is the opposite of what one would expect, which is for PFP growth to be greatest in the years immediately after privatization (*i.e.* 1998-2002) and to moderate as time goes on. The last two sentences that Meyrick cites make it clear that PEG is referring to this PFP acceleration and the GDBs' unexpected "patterns of PFP gains" over time. We therefore believe that, when this passage is seen in context, it is clear that PEG is attempting to analyze a curiosity from Meyrick's research, and we can find nothing fundamental in the drivers of long-run PFP growth for GDBs that would lead PFP for these firms to accelerate over time when this was not the case for electricity distributors. Meyrick's conclusion that PEG has contradicted itself is therefore based on a misreading of our report, and we believe interested parties can confirm this is the case by reviewing the full context in which this passage appears.

PEG therefore reiterates its conclusion regarding the inapplicability of power distribution precedents. Meyrick's Response has presented no new information or analysis that would cause us to modify those views. Moreover, the criteria developed in our original report conclude that it is generally not reasonable for regulators to rely *entirely* on precedent when reaching decisions. In almost all instances, it is appropriate to undertake independent analysis to evaluate whether forecasts are consistent with the Gas Code. Since it is not sufficient to rely solely on regulatory precedent to support a given forecast, and we do not believe that precedents from industries other than gas distribution are relevant in any case, we therefore conclude that precedents cited by Meyrick do not satisfy the criterion of being "best estimates determined on a reasonable basis."

3.3.5 Overview of Meyrick Recommendations

The ESC asked PEG to undertake an objective review of Meyrick's recommendations on all the rate of change parameters, including opex PFP growth. PEG's initial review worked within the four walls of the evidence presented by Meyrick. We also developed a detailed list of evaluation criteria so that the bases by which we evaluated Meyrick's recommendations were as explicit and transparent as possible.

PEG has now reviewed Meyrick's Response to our original report, and we again conclude that the foundations for Meyrick's 0.8% recommendation are plainly, and unambiguously, deficient. Meyrick's PFP forecasts for the GDBs are circular and self-referential and do not reveal anything except the opex PFP growth assumptions that the GDBs have chosen to embody in their opex projections. There is no systematic or consistent relationship between the GDBs' historical PFP and the series that BIS uses to project opex PFP going forward, so there is no reason to believe these projections will bear any relationship to the opex PFP gains the GDBs can be expected to achieve. Opex PFP trends for US GDBs are 2% or more and therefore well above Meyrick's recommended 0.8% trend, even though gas distribution is much more mature in the US and therefore characterized by slower output growth (which, all else equal, translates into slower opex PFP growth than would be expected in the faster-growing Victorian market). Finally, PEG has presented an array of evidence which shows that the PFP trends of different industries – including electricity distribution - are not necessarily relevant for projecting gas distribution opex PFP trends.

Because PEG concludes that none of the PFP material presented by Meyrick satisfies Sections 8.2(e) and 8.27 of the Gas Code, an alternative basis for projecting opex PFP *must* be developed for the GAAR. PEG developed an econometric model that reflected the underlying drivers of opex PFP growth, and we combined this estimated model with changes in business conditions for the GDBs to generate predictions for each company's opex PFP growth. As our original report stated, PEG believes our PFP recommendations are feasible, objective, rigorous, robust, consistent with economic theory and long-run behavior, and tailored to be consistent with forward-looking information on the GDBs' business conditions over the term of the GAA. We also believe the approach is transparent, although it is somewhat complex. However, this complexity is mitigated by the fact that it builds on a theoretical framework that both Meyrick and PEG support and which has previously been employed in TFP research in Victoria. Below we address Meyrick's critique of PEG's econometric approach and results.

3.3.6 Meyrick Review of PEG's Recommended Approach

3.3.6.1 Basic Approach

On a methodological level, Meyrick says indexing methods are generally preferred to econometric methods for estimating opex PFP trends. PEG agrees, and whenever possible our preferred approach for estimating TFP or PFP is to use indexes. Indexing methods will estimate historical PFP trends using observed data. These trends are appropriate for regulatory applications if an industry's historical PFP trends can be considered a good guide for its future PFP growth. When this is not the case, however, some alternative method must be used.

The conditions for Victoria's gas distribution industry make index-based methods using historical data inappropriate for the GAAR. Meyrick has estimated historical PFP growth for the GDBs' of more than 6% per annum since privatization. Meyrick and PEG agree that this experience includes one-time effects that are unlikely to be repeated, so it is not reasonable to use the historical trend for the rate of change formula. Unfortunately, Meyrick's alternate recommendation is not acceptable since it is not objective, does not reflect the business conditions of Victoria's gas distributors, and is not developed using accurate PFP information.

The econometric approach is well-suited for projecting PFP under precisely the conditions that currently prevail in Victoria's gas distribution industry. Econometrics can estimate the underlying "drivers" of PFP growth through rigorous statistical methods that are applied to samples of gas distributors operating under a wide variety of business conditions. Once those underlying PFP "drivers" inherent in gas distribution technologies are estimated, they can be combined with Victorian data on the projected changes in the business condition variables that apply for specific GDBs. This information is then brought together using a methodological framework that PEG has detailed in Victoria and which Meyrick says is "well grounded in economic theory." PEG recommended this econometric approach to developing an appropriate opex PFP projection for the GAAR, and we continue to believe it is most likely to develop "best estimates determined on a reasonable basis" for opex PFP trends.

3.3.6.2 Functional Form

Meyrick objects to the functional form that PEG uses for our econometric work. It writes "PEG (2007a) uses the now relatively old translog functional form. Guilkey, et al (1983) is quoted as evidence that 'the translog is the most reliable of several alternatives' (PEG 2007a, p. 75). However, this ignores the significant developments that have occurred in the development of functional forms over the last 25 years."[45]

These generally disparaging remarks contrast with Meyrick's previous work and comments in the GAAR. In a report dated March 26, 2007 – the same day that it finalized its recommendations for the rate of change formula – Meyrick (2007e) completed a benchmarking paper which used the translog form to estimate a GDB cost function. In discussing this choice for its functional form, Meyrick wrote:

> The translog cost function has been widely used in economic research and in regulatory hearings. It has the major advantage of being an approximation to a wide range of functional forms and is generally a robust functional form for empirical work. The economic theory that underlies the translog cost function also enables a number of parameter restrictions to be imposed that are economically sensible and that also facilitate estimation.[46]

[45] Meyrick (2007a), p. 35.
[46] Meyrick (2007e), p. 16.

Far from being old, tired and outdated, the translog had many commendable properties when Meyrick chose to use it for its own work in March 2007. It is "widely used in economic research and regulatory hearings." It also has a "major advantage of being an approximation to a wide range of functional forms." The translog is also a "generally robust functional form for empirical work" with properties "that are economically sensible and that also facilitate estimation." Robustness, versatility and widespread application in the economic literature are desirable traits for econometric cost function specifications, and Meyrick (2007e) extols the translog on all these grounds. One will also search Meyrick's March 2007 report in vain for any mention of the translog's deficiencies, which it highlighted in October 2007 after this same functional form was used by PEG.

Regardless of whether Meyrick has a flexible position on the merits of the translog, the disparaging remarks it makes regarding this functional form are not valid. It is true that the translog has been around for a significant period of time, but it is more accurately described as "venerable" than old. This functional form is still widely used and, in fact, remains the workhorse of applied cost function research. PEG investigated this issue by examining the papers published in the *Journal of Productivity Analysis* over the five year period from November 2001 to October 2006.[47] We determined how many of these papers presented cost or production function research and, of these, how many used the translog form. This literature is obviously most relevant to the current issue, but it should be noted that other, non-cost or production applications of the translog form were published by the *Journal of Productivity Analysis* during that time. One of these papers estimated a profit function and was co-authored by Denis Lawrence of Meyrick.

Our research showed that the translog remains the dominant functional form in applied cost and production function research. During this five year period, there were 18 econometric cost function papers published, and nine of these used the translog form.[48] Four of the remaining nine papers used simple, non flexible-form cost functions,

[47] Issues for 2007 are not yet available on-line.

[48] These papers are the following: 1) Huang, T. & Kao, T. Aug 2006. Joint estimation of technical efficiency and production risk for multi-output banks under a panel data cost frontier model, Journal of Productivity Analysis 26(1), p. 87; 2) Bitros, G. & Panas, E. Aug 2006. The inflation-productivity trade-off revisited. Journal of Productivity Analysis 26(1), p. 51 ; 3) Alvarez, A., Amsler, C.,

while the five other papers used a total of three other flexible form functions. There were also 12 econometric production function papers published over the same five year period, and 10 of these used the translog form.[49] Overall, PEG's survey reveals that the translog form remains extremely viable and active in applied cost and production function research. Indeed, the translog is still the dominant cost function form, as it has been for decades, because of the positive properties that Meyrick originally noted which increase its robustness, applicability and versatility.

Another concern that Meyrick raises about the translog is that it does not perform well when the function contains more than one output, as PEG's econometric function does. This result is purportedly demonstrated mathematically in Appendix A of Meyrick (2007a). However, this mathematical proof relies on assumptions that are not valid for the GDBs. In particular, immediately after equation (10) on page 55, Appendix A says

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Orea, L., & Schmidt, P. Jun 2006. Interpreting and Testing the Scaling Property in Models where Inefficiency Depends on Firm Characteristics. Journal of Productivity Analysis 25(3), p. 201 ; 4) Piacenza, M. Jun 2006. Regulatory Contracts and Cost Efficiency: Stochastic Frontier Evidence from the Italian Local Public Transport. Journal of Productivity Analysis 25(3), p. 257; 5) Choi, O. & Stokes, J. Apr 2006. The Dynamics of Efficiency Improving Input Allocation, Journal of Productivity Analysis 25(1), p.159; 6) Kompas, T. & Che, T. Jul 2005. Efficiency Gains and Cost Reductions from Individual Transferable Quotas: A Stochastic Cost Frontier for the Australian South East Fishery, Journal of Productivity Analysis 23(3), p. 285; 7) Aubert, C. & Reynaud, A. Jul 2005. The Impact of Regulation on Cost Efficiency: An Empirical Analysis of Wisconsin Water Utilities, Journal of Productivity Analysis 23(3), p. 383; 8) Orea, L., Roibás, D. & Wall, A. Jul-Sep 2004. Choosing the Technical Efficiency Orientation to Analyze Firms' Technology: A Model Selection Test Approach, Journal of Productivity Analysis 22(1-2) p. 51; and 9) Greene, W. Apr 2003. Simulated likelihood estimation of the normal-gamma stochastic frontier function. Journal of Productivity Analysis 19(2), p. 179.

[49] These papers are the following: 1) Tsekouras, K., Daskalopoulou, I. Apr 2006. Market Concentration and Multifaceted Productive Efficiency. Journal of Productivity Analysis 25(1), p. 79; 2) Caputo, M. & Paris, Q. Nov 2005. An Atemporal Microeconomic Theory and an Empirical Test of Price-Induced Technical Progress, Journal of Productivity Analysis 24(3), p. 259; 3) Huang, T. Nov 2005. A Study on the Productivities of IT Capital and Computer Labor: Firm-level Evidence from Taiwan's Banking Industry, Journal of Productivity Analysis 24(3), p. 241; 4) Cuesta, R., & Zofío, J. Sep 2005. Hyperbolic Efficiency and Parametric Distance Functions: With Application to Spanish Savings Banks, Journal of Productivity Analysis 24(1), p. 31; 5) Jensen, U. May 2005. Misspecification Preferred: The Sensitivity of Inefficiency Rankings, Journal of Productivity Analysis 23(2), p. 223; 6) Sun, C. Jul-Sep 2004. Market Imperfection and Productivity Growth-Alternative Estimates for Taiwan, Journal of Productivity Analysis 22(1-2), p. 5; 7) Ilmakunnas, P., Maliranta, M., & Vainiomaki, J. May 2004. The Roles of Employer and Employee Characteristics for Plant Productivity, Journal of Productivity Analysis 21(3), p. 249; 8) Karagiannis, G., Midmore, P., & Tzouvelekas, V. Jul 2002. Separating Technical Change from Time-Varying Technical Inefficiency in the Absence of Distributional Assumptions, Journal of Productivity Analysis 18(1) p. 23; 9) Biorn, E., Lindquist, K., Skjerpen, T. Jul 2002. Heterogeneity in Returns to Scale: A Random Coefficient Analysis with Unbalanced Panel Data. Journal of Productivity Analysis 18(1), pg. 39; and 10) Banker R.D.; Janakiraman S.; Natarajan R. Jan 2002. Journal of Productivity Analysis. Evaluating the Adequacy of Parametric Functional Forms in Estimating Monotone and Concave Production Functions. pp. 111-132(22).

"if we also ask that f (the factor requirements function) be consistent with a constant returns to scale technology, then f must satisfy the following property…," which is summarized in equation (11). But this is not a reasonable condition to "ask" of a factor requirements function for natural gas distributors. Gas distribution is provided by regulated monopolies rather than competitive markets because it is a "natural monopoly." Natural monopoly technologies are, in turn, characterized by economies of scale over very large ranges of potential output. Indeed, the existence of extensive scale economies is the reason it is more cost effective for all customers in an assigned service territory to be served by a single, regulated utility than by competing alternative distributors. The technology that applies to the GDBs is therefore not characterized by constant returns to scale, as Appendix A assumes, so the assumption that is made after equation (10) is not satisfied. The mathematical exposition and conclusions past this point therefore become moot since they rely on an assumption that is not valid for the GDBs.

3.3.6.3 US Data

Meyrick also criticizes the use of US gas distribution data to estimate PEG's econometric model. It claims that "underlying differences in business conditions in operating conditions" between the US and Australia "are unlikely to produce good estimates" for the GDBs. It also cites a passage from work it presented in New Zealand on this issue, which it says also applies in Australia and which we reproduce below:

> 'equally or more important [than scale differences] is the fact that the key operating environment differences between the US and NZ are not included. These are climatic differences, the presence of perma-frost in much of the US, differences in industrial usage, population density and lifestyle influences to name but a few. The main lifestyle difference is the North American practice of keeping homes heated to summer temperature levels in the winter compared to the Australasian practice of heating homes more moderately…
>
> In practice, econometric models have proven relatively unsuccessful at distinguishing the effects of these key operating environment differences due to statistical difficulties (lack of variation in key variables, multicollinearity, etc.). While these factors will be of low importance when comparing NZ and Australia which have relatively similar operating environments, they will be of critical importance in comparing NZ and the US distributors.'[50]

[50] Meyrick (2007a), p.36 referencing Meyrick (2004), p. 43.

Again, the contrast between this extensive critique and other work that Meyrick has presented in the GAAR is striking. Meyrick (2007e) not only used a translog cost function but estimated this function using US gas distribution data. In Meyrick's (2007e) analysis, the parameters of the translog cost function were estimated using US sample data, and the coefficients Meyrick estimated were combined with the business conditions of a Victorian GDB to generate (cost) predictions that reflected that GDB's particular conditions. This is *exactly* the same process that PEG has used to develop econometric projections of PFP growth for the GDBs and which Meyrick now criticizes.[51] In both cases, econometrics is used to estimate the underlying "drivers" of costs, and estimates of these cost drivers are combined with data on the Victorian GDBs' specific business conditions to develop cost – or PFP - predictions that are appropriate for that GDB.

Moreover, Meyrick (2007e) contains no discussion of the litany of business condition differences between the US and Victorian GDBs which would invalidate comparisons between the countries. Indeed, the title of Meyrick's (2007e) paper is "Cost Comparisons of Multinet and United States Gas Distribution Businesses Allowing for Operating Environment Differences"! An observer who read only Meyrick's October 2007 Response to PEG's work might fairly conclude that Meyrick believes it is impossible to make appropriate cost comparisons between the US and Victorian GDBs while allowing for operating environment differences, but Meyrick clearly held a different position during the GAAR in March 2007.

Meyrick (2007e) also contains other statements that imply that, at least for the GDB in question (Multinet), any differences between US and Victorian GDBs are not material in any case. Meyrick (2007e) evaluates Multinet on a variety of business condition variables. It concludes that "Multinet lies well within the range of the US data on all these (operating environment) measures, (but) its relatively low non-industrial throughput proportion and relatively low residential energy density mean that it is important to make efficiency comparisons on a basis that takes these operating

[51] PEG used a translog cost function and estimated its parameters using US data, but the variables entering into the Meyrick and PEG functions differed. This is appropriate since PEG estimated a short-run cost function, where GDB opex was the dependent variable, and Meyrick estimated a total cost function where total GDB cost was the dependent variable. Short run cost functions should be used to project opex PFP. PEG's cost model also used actual opex data to estimate our model, whereas Meyrick used (inaccurate) opex proxies in its total cost measure.

environment differences into account."[52] This passage implies that Meyrick believed the business conditions between US GDBs and Multinet were relatively comparable, but that it was particularly important for econometric models to control for differences in gas consumption for residential customers (*i.e.* residential energy density) and the proportion of sales to non-industrial customers. Meyrick's econometric model includes variables that reflect both of these business conditions and so does PEG's.[53]

PEG has also previously responded to Meyrick's list of purported differences in business conditions between the US and ANZ gas distributors. Meyrick first made these points in response to a study PEG presented in NZ, and we responded in a letter we were asked to write to the Ministry of Economic Development. We reproduce the relevant parts of this response (Kaufmann (2005b), pp. 5-6) below:

> In addition to scale adjustments, the Commission states that "key operating environment differences between New Zealand and the US are not included" in PEG's benchmarking analysis.[54] The operating conditions specifically mentioned in the Final Report are climatic differences, the presence of perma-frost, differences in industrial usage, population density, and lifestyle differences. All of these factors were also mentioned in Dr. Lawrence's *Review*; the "lifestyle differences" primarily refer to North Americans' penchant for heating their homes to near-summer levels during the wintertime, compared with more moderate winter heating by New Zealand gas users.
>
> In most cases, these points are unfounded. PEG's analysis does control for most of the listed factors through our selected "cost drivers." There is accordingly no need to control for these operating factors separately since the cost impacts of these variables are already reflected in the model. Dealing with each variable in turn:
>
> - Climatic differences: Climate (air temperatures, wind, and precipitation) does not impact gas distribution cost structures directly. This differs from electricity distribution where, for example, differences in precipitation and lightning strikes can affect the number of weather-related outages a distributor experiences and therefore its outage restoration and tree trimming costs. These factors are not relevant for gas distribution since gas delivery infrastructure is almost wholly underground. Instead, climate affects cost indirectly through its impact on customer usage; all else equal, customers clearly use gas more for space heating in colder climates. However, this factor is already reflected in our benchmarking model, which includes total usage

[52] Meyrick (2007e), p. 15.
[53] See Kaufmann (2007a), Table 2.
[54] Kaufmann (2005b), *op cit*, p. 11.5.

(volumes delivered) as an explanatory model variable. Gas volumes rather than climate is the real cost driver, and since our model controls for this factor, the Commission's concern on this point is unfounded.

- Presence of perma-frost: Differences in perma-frost can impact gas distribution costs. For example, greater frost levels typically lead to more gas leaks and leak repair costs. PEG does control for this in comparisons among US gas distributors, but we could not do so in this study since we were unable to locate data on frost depth levels for NZ gas distributors. However, our US results show that this factor exerts a modest (although not insignificant) impact on gas distribution costs compared with the major cost drivers that were included in our model.

- Differences in industrial usage: Industrial usage is simply a contributor to total gas usage, which is already included in our model. Since our model already controls for this factor, the Commission's concern on this point is unfounded.

- Population density: A better proxy for this factor is included in our model. Our benchmarking work shows that customer density is superior to population density as a cost driver measure. The reason is that customer density has a more direct relationship to the gas distribution assets that are installed and must be maintained and, eventually, replaced. Customer density is typically measured as numbers of customer per km of distribution main. Our model includes both customer numbers and total km of distribution main as cost drivers. It therefore automatically reflects the customer density relationship; including this as a separate, independent variable would be redundant and would only "rearrange" the cost driver estimates on the separate customer number and line km variables. Since our model already controls for this factor, the Commission's concern on this point is unfounded.

- Lifestyle differences: Again, this factor matters only as it may indirectly impact consumption and gas deliveries. Since our model already controls for gas deliveries as a cost driver, the Commission's concern on this point is unfounded.

In sum, the Commission's Final Report errs with respect to four of the five environmental variables that it believes are not properly controlled for in our analysis. PEG considered controlling for the remaining variable, the level of perma-frost, but data on this measure did not exist in New Zealand. Perma-frost exerts a relatively small impact on any gas distributor's cost level, and controlling for this variable would certainly not reverse PEG's findings that Vector and NGC's actual gas distribution costs were significantly less (than) their predicted values.

Finally, we should note that PEG is no longer using Meyrick's ANZ database for the purposes of estimating our cost function model. The information in this dataset is clearly inferior to our US GDB database.[55] PEG has developed a high quality dataset for US GDBs that we have used to estimate TFP and associated PFP trends in many regulatory proceedings. These data are also appropriate for predicting or projecting GDBs' costs or PFP growth using econometric methods. Meyrick has in fact used US data to estimate econometric models and predict costs for Victorian GDBs in the GAAR, and PEG uses the exact same process as Meyrick for projecting the Victorian GDBs' PFP growth. Meyrick's original work in the GAAR never mentions differences in business conditions that would make it inappropriate to use US datasets to estimate the fundamental "drivers" of costs and PFP growth and, for the reasons mentioned above, PEG has previously considered the points raised in Meyrick's Response and concluded that they were not valid. Meyrick therefore has presented no new information in its Response that would undermine the use of accurate US data, either in Meyrick's previous work in the GAAR or PEG's subsequent use of these data.

3.3.6.4 System capacity

Meyrick's Response also faults PEG's econometric cost model because it does not include system capacity as an output. Meyrick asserts that this is a major oversight. It concludes that "(t)his omission alone, thus, means that any econometric results obtained from this model will be biased."[56]

Again, this criticism conflicts with Meyrick's other work in the GAAR. Meyrick estimated a translog cost function using US sample data, and this regression did not include a system capacity output. Meyrick's March 2007 report never hints that this omission may lead to biased coefficients, in contrast with its view in October 2007 that "any econometric results" without this variable must be biased. Moreover, if Meyrick truly believed the coefficients from its US cost model were biased, it would never have

[55] For example, capital cost is not measured consistently across ANZ companies and most of the ANZ companies' opex is not their actual opex but rather what was allowed by regulators. The US GDB data does not have these problems.

[56] Meyrick (2007a), p. 37.

used those coefficients to predict Multinet's opex. Any such cost prediction must necessarily also be biased and therefore lead to inappropriate and misleading cost comparisons between Multinet and US GDBs. Yet Meyrick did use the coefficients estimated from the US sample for precisely this purpose.

The reason neither Meyrick nor PEG included a system capacity measure in our US cost functions is that these data do not exist in the US. Meyrick's criticism is therefore not practical and, if Meyrick's point about bias is taken at face value, it would imply that no econometric work using US GDB data should even be contemplated since "any" econometric results using these data must therefore be biased. Meyrick itself has not adopted this stance in the GAAR, either in March 2007 or, relatedly, in October 2007, when it put forward an estimate of US GDBs' opex PFP growth that did not include system capacity as an output. Such a conclusion would also run counter to the fact that academics, consultants and regulators throughout the world use data from the US GDBs in econometric research on gas distribution cost.

PEG also believes that there is little empirical or substantive basis for Meyrick's concern in any case. Meyrick presented estimates of PFP trends for Victoria's GDBs using two different measures of comprehensive output. The first included a system capacity measure, as well as customer numbers and throughput, as outputs. The second measured output using customer numbers and throughput only. Over the 1998-2006 period, output quantity grew at an average rate of 1.77% using the first output measure and at an average rate of 1.79% using the second output measure. PEG had some concerns about the construction of Meyrick's system capacity measure, but we concluded that "we do not believe this is a material deficiency, however, because the output quantity measure was demonstrated to be robust in the alternate, two-output specification that excluded system capacity."[57] This result shows that, in Victoria, there is no foundation

[57] Kaufmann (2007a), p. 23. We had concerns about Meyrick's system capacity measure because it was not clear from its worksheets how Meyrick constructed this variable. This point is also material for evaluating Meyrick's point about the importance of system capacity. That is, the system capacity data that Meyrick claims are so critical for estimating cost functions are not readily available in Australia either, and Meyrick had to construct them. The construction of these variables could in fact be valuable for cost research, but the fact that they do not in fact exist in Australia should not automatically rule out econometric work using Australian data by other researchers simply because they have not constructed these proxies (according to Meyrick, such work would be biased). Moreover, because Meyrick's workpapers did not provide enough information, it must be recognized that Meyricks' system capacity

for Meyrick's concern that "changes in system capacity follow a different pattern to changes in throughput and customer numbers," and which in turn could lead to biased estimates of PFP "drivers."[58] Now, the same relationship does not necessarily hold in the US but, because the data on system capacity do not exist, this cannot be determined one way or the other. It is therefore fair to say that all the data that have been presented in the GAAR, or that exist in Victoria and the US, imply that Meyrick's concern is unwarranted. PEG also believes it is more appropriate to conclude that the relationship between changes in system capacity and changes in other outputs will not differ radically between the US and Victoria, since the same types of materials and pipes are used in new construction in both jurisdictions.

PEG also believes there are other substantive reasons why the lack of a system capacity measure in GDB cost models is not material. PEG explained these reasons in a GDB proceeding in New Zealand, where Meyrick raised the same concern. PEG provided a Cross Submission that addressed this issue. We reproduce the relevant sections of this Cross Submission below.

> One concern noted for PEG's benchmarking study was the lack of a system capacity output. I do not believe that the lack of such a measure is a significant deficiency in our study for several reasons. First, "capacity" is much less relevant as a cost driver for gas distribution than for gas transmission. The capacity of gas transmission systems can vary dramatically. Gas transmission pipelines vary in diameter from four inches to as much as 60 inches; the capacity of a 60 inch diameter pipeline of a given length is more than 2000 times greater than that of a pipe with a four inch diameter. In contrast, the diameter of gas distribution main does not vary nearly as much. Data from the American Gas Association show that US gas distributors report gas distribution main from 1 inch to 12 inches, but 58% of all main is less than 2 inch diameter and 28% is between two and four inches. Only 14% of distribution main is therefore more than four inches in diameter, and nearly all of this is older and made from steel or iron. PEG's econometric model includes a variable for the percentage of main that is not cast iron and thus controls for the higher costs of using older, and larger diameter, pipe. Compression can also be used to increase the effective capacity of gas pipelines, but nearly all such compression is used for transmission rather than distribution systems. In addition, unlike electricity, natural gas can be stored.

proxies have not been adequately examined or tested in the GAAR. PEG believes it would not be appropriate for an econometric model to be disregarded, as Meyrick recommends, simply because it did not include a relatively unexamined variable, the details of whose construction remain murky, and which does not exist from standard, publicly verifiable data sources in any case.

[58] Meyrick (2007a), p. 37.

> Gas distributors therefore are less constrained to size the capacity of their operations to meet maximum system demand. For all these reasons, I believe outputs that reflect peak demand/system capacity are much less essential for gas distribution benchmarking than for gas transmission or power distribution benchmarking.[59]

Meyrick chose not to address PEG's points in its subsequent work in this proceeding, and PEG continues to believe these points are valid and stand unrebutted. They also mitigate Meyrick's concerns about the lack of a system capacity measure in econometric cost modeling.

In a perfect world, data on system capacity for US gas distributors would exist. The fact that they do not should not rule out econometric research. Such a view would make "the perfect the enemy of the good." Moreover, for the reasons discussed above, PEG does not believe the lack of system capacity measures materially impacts our results in any case. Accordingly, there is no foundation for Meyrick's concern on this point.

3.3.6.5 Capital Stock Measures and Coefficient

Meyrick makes two main points regarding capital variables in our econometric model. First, it argues that there be will be biases in productivity measures and econometric studies that use deflated asset values rather than physical asset measures (with the exception of a "small residual other capital component" that cannot be measured using physical units). It therefore recommends that changes in physical capital inputs be used to project PFP. Second, it states that the positive coefficient on the capital stock in PEG' model is a "major problem."

PEG has responded at length to Meyrick's first point in other proceedings.[60] We will not revisit those debates here, because doing so would lead us astray of the key issues in the current proceeding. Suffice it to say that Meyrick stands virtually alone in recommending that physical capital units be used in productivity measurement for regulatory applications. These views conflict with the trend in the economics profession for more than 40 years, the methods used to measure capital by US and Australian government agencies, and every energy utility productivity study that has ever been

[59] Kaufmann (2004a), Cross Submission, pp. 7-8.
[60] Kaufmann (2005a), pp. 16-19.

approved in North American regulation, where there is more testimony on this issue than elsewhere.

Meyrick's recommendation to use changes in physical capital inputs would also be internally inconsistent with the econometric model. PEG uses deflated asset values to measure capital in its US cost model. Incidentally, this is also true of Meyrick's US econometric work, which says "we follow the PEG (2004a) approach of using an overall measure of capital input based on aggregate asset value."[61] PEG's estimated value for the capital coefficient, which is used to project PFP, is therefore linked to monetary capital asset values. This coefficient would have been different if physical capital units were used in the cost function (assuming such an approach is even feasible). It would therefore be inappropriate to project PFP growth by multiplying a coefficient that is estimated using monetary capital values by a completely different measure of capital inputs. This approach will necessarily be internally inconsistent and inaccurate, regardless of the merits of Meyrick's capital measure.

In an effort to support its capital recommendations, Meyrick has also not accurately reported PEG's work. When referencing the index of physical capital input Meyrick developed for the TFP index it presented in the GAAR, Meyrick implies that we endorse this procedure by saying that "PEG (2007a, p. 40) acknowledges that the Meyrick productivity estimates are 'defensible and generally accurate.'"[62] This distorts PEG's original report. What PEG says in the referenced sentence is "(o)verall, PEG believes Meyrick's *historical opex PFP measures* are defensible and generally accurate." PEG clearly expressed support only for Meyrick's historical opex PFP, but Meyrick obfuscates this point by substituting the term "productivity estimates" for words it could have quoted and which would clearly express PEG's views – but which do **not** support Meyrick's capital measures. Moreover, PEG's quantitative review never even referenced Meyrick's TFP results but only examined its opex PFP evidence, so Meyrick has no basis for saying anything about PEG's evaluation of its capital measures in the GAAR. It is also important to note that our statement only supports the general validity of Meyrick's *historical* PFP measures, in distinction to its PFP projections. Finally, Meyrick knows

[61] Meyrick (2007e), p. 9.
[62] Meyrick (2007a), p. 41.

from our previous debates that we do not agree with its approach to measuring capital and would not defend it or deem it to be accurate. It is not clear why Meyrick chose to make this gratuitous and misleading statement, but it represents another attempt to obfuscate the distinction between TFP and PFP, only the latter of which is relevant to calibrating the rate of change formula.

Meyrick's second point regarding capital concerns the sign of the capital stock coefficient in our model. Meyrick says that "the main problem with the results (and it is a major problem) is that the estimated coefficient that corresponds to the capital quantity variable, KQ, is 0.057 which is positive instead of being negative. Thus, taken at face value, if a gas distributor increases its capital input, holding constant input prices, outputs and operating cost environmental variables, then opex cost will increase instead of decrease, which is contrary to economic theory."[63]

Meyrick's critique is grounded solely on the theoretical merits of PEG's results, but it displays no awareness of the relevant empirical literature on the subject. Certainly economic theory should not be disregarded, and it is a valuable signpost for economic and econometric analysis. But ultimately theory exists to be tested. Economic theory is not fixed in stone, and theories are constantly being qualified, modified and at times abandoned entirely if they are not supported by empirical evidence. This process is of course not unique to economics but is common to all scientific disciplines, which should be guided by the objective of trying to explain the observable world rather than resting solely on theoretical argument or received authority.

Meyrick is apparently not aware that, for more than 20 years, many economists have found positive estimates on capital quantity measures in short run cost models. PEG's research (which we believe is representative of the literature, although we admit it is not exhaustive) also shows that more published economic papers have found positive coefficients on capital stock variables than the negative estimates that are predicted by theory. Certainly, a large number of peer reviewed articles have been published with positive coefficients on capital variables, which is not consistent with the conclusion that this is viewed as a "major problem" which would, presumably, cause such articles to be

[63] Meyrick (2007a), p. 38.

rejected out of hand.[64] Instead, the economics profession has viewed these results as an unexpected phenomenon that needs to be explained, and a number of statistical and behavioral hypotheses have been advanced for this purpose.

This issue has been discussed in a recent published paper by Fraquelli et al on the regulation of public transit networks. In describing their econometric results, they say

> The parameters' signs are consistent with the expectations. The only exception concerns the positive first-order coefficient associated with the fixed input β_k. The evidence that the variable costs increase with larger rolling stocks is not consistent with the microeconomic theory. (footnote: *This seems to be a general problem that characterizes the use of a variable cost model*, not only in the transportation industry. For a discussion on these issues, see also Fabbri (1998)). With regards to this problem, an intense debate arose in the literature. According to Filippini (1996), the positive sign of β_k is due to a problem of multicollinearity in cases where there exists a positive correlation between the dependent variable and the capital measure. The alternative argument suggested by Caves et al. (1985) and Windle (1988) is that the positive sign of β_k reflects an industry which does not minimize costs in the long run and therefore employs too much capital in the production process.[65] (footnote moved to text, emphasis added)

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[64] In the electric power industry, examples of peer-reviewed published papers that have found positive coefficients on capital stock measures include Nelson, R A, 1989, "On the measurement of capacity utilization," *Journal of Industrial Economics,* 37, 273-86; Callan, S.J., 1991, "The sensitivity of productivity growth measures to alternative structural and behavioral assumptions: an application to electric utilities 1951-1984, *Journal of Business and Economics Statistics*, 9, 207-13; Hammond, D.J., 1992, "Privatization and the efficiency of decentralized electricity generation: some evidence from inter-war Britain," *The Economic Journal*, 102, 538-53; Salvanes, K G and Tjota, S., 1994, "Productivity differences in multiple output industries: An empirical application to electric distribution," *Journal of Productivity Analysis*, 5 (1): 23-43; and Fillipinni M., 1996, 'Economies of scale and utilization in the Swiss electric power distribution industry,' Applied Economics, 28, 543–50. Examples of studies that have found positive coefficients on capital variables in short run models estimated in other industries include Caves, D.W, L. Christensen, and J. Swanson, 1981, "Productivity Growth, Scale Economies, and Capacity Utilization in US Railroads: 1955-74," *American Economic Review*, 71:5, 994-1002; Cowing, T and Holtmann, A G, 1983, "Multiproduct short run hospital cost functions: Empirical evidence and policy implications from cross-section data," *Southern Economic Journal*, 49, 637-53; Caves D.W., L.R. Christensen, M.W. Tretheway and R. Windle, 1985, 'Network effects and the measurement of returns to scale and density for U.S. railroads', in Daughety, A., Analytical Studies in Transport Economics, Cambridge University Press, Cambridge, pp. 97–120; Guyomard, H. and D. Vermersch, 1989, "Derivation of long-run factor demands from short-run responses," *Agricultural Economics,* 3 (2): 213-230; Levaggi, R., 1994, 'Parametric and non-parametric approach to efficiency: the case of urban transport in Italy', Studi Economici, 49, 53, 67–88; Windle, R.J., 1988, 'Transit policy and the cost structure of urban bus transportation', in J.S. Dogson and N. Topham (eds), Bus Deregulation and Privatization, Averbury, Aldershot; Fabbri, D., 1998, 'La stima di frontiere di costo nel trasporto pubblico locale: una rassegna e un'applicazione', Economia Pubblica, 3, 55–94; and Fraquelli, G., M. Piacenza and G. Abrate, 2004, "Regulating public transit networks: How do urban-intercity diversification and speed-up measures affect firms' cost performance?" *Annals of Public and Cooperative Economics,* 75:2 2004 pp. 193–225.

[65] Fraquelli, et al., *op cit*, p. 212.

PEG believes the Caves *et al.* and Windle explanations are especially relevant for the gas distribution industry, since they resonate and are logically consistent with our other work in regulatory economics. It has been argued for decades that cost-based regulation can create incentives for utilities to over-capitalize their systems. This is the well-known "Averch-Johnson" effect. Findings of positive coefficients on capital stock variables in short run cost models could therefore tend to support this broader hypothesis from regulatory economics. Indeed, while a negative coefficient on the capital stock variable is certainly predicted by standard economic theory, the economic theory for regulated enterprises (*e.g.* the Averch-Johnson effect) suggests that there are sound theoretical reasons for this coefficient to be more ambiguous for utilities, since the incentives created by cost-based regulation can run counter to those inherent in standard profit-maximizing behavior. Such a hypothesis would also be generally consistent with the applied empirical literature, where both positive and negative capital quantity coefficients have been estimated in short-run cost models.

Observers should also not conclude that a tendency to over-capitalize is necessarily absent when utilities are subject to incentive regulation. Any time capital costs and operating costs are subject to different regulatory approaches, as they are in the "building block" approach to CPI-X regulation used in Australia, utilities will potentially have unbalanced incentives to manage their costs. This could lead to weaker incentives to control capital costs compared with opex. Although we emphasize that we have no evidence that this is or has been the case with Victoria's GDBs, PEG has long warned that this could be an issue in building block regulation, and indeed we have presented evidence that such imbalanced incentives has led to over-capitalization in earlier UK applications of building block, incentive regulation.[66] It would therefore be inappropriate for Victorian observers simply to assume that overcapitalization "can't happen here" because the industry is subject to incentive regulation.

In sum, when PEG was undertaking its empirical work, we were aware of what economic theory predicted for the sign on the capital quantity coefficient, but we were also aware of the empirical literature on this subject. PEG's finding of a positive coefficient is well within the mainstream of this literature, where positive coefficients on

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[66] See Kaufmann and Lowry (1997), p. 59-60.

capital variables are common and not viewed as a "major problem" that would lead journals to conclude that such econometric results are fundamentally flawed and not suitable for publication. Instead, positive coefficients on capital variables are so common that they have been a "general problem" that runs counter to pure economic theory and which has, in turn, prompted revised theoretical explanations. This is ultimately not problematic from a theoretical sense, but simply demonstrates how economics (and other sciences) advance in trying to explain unexpected findings from the observed world. Thus while PEG's result may be unexpected from a generic theoretical standpoint, it is both commonplace and reasonable when viewed in the broader context of regulatory economics and the relevant empirical literature. PEG's familiarity with this empirical literature and broader context increased our confidence in the econometric results. Meyrick's Response has not taken all relevant information into account when evaluating the sign on the capital quantity coefficient, and a more complete analysis shows that PEG's result is reasonable, mainstream and not a "major problem."

It should also be noted that PEG's model includes other variables that reflect the impact of changes in capital spending on opex. This effect is reflected in the coefficient on the percent of gas distribution main constructed of cast iron and bare steel. Our econometric results show that GDBs' opex declines when they have less relatively less cast iron and bare steel main. This is intuitive and expected, because cast iron and bare steel systems are more prone to gas leakage than distribution main constructed with plastic, and GDBs that need to address a greater number of gas leaks will have higher maintenance costs. This result implies that if a GDB is reducing the percentage of its main that is constructed with cast iron or bare steel, it will tend to have relatively lower opex.

This finding is directly relevant to the capital-opex substitution issue, which standard economic theory predicts would be manifested in a negative sign on the capital quantity coefficient in short run cost models. GDBs that replace relatively old cast iron and bare steel main with newer plastic pipe are reducing the share of their systems constructed with cast iron and bare steel. Such capital replacement is a component of capital expenditures. It follows that GDBs undertaking such replacement expenditures should be reducing their opex, and this result is reflected in PEG's econometric model and our PFP projections. That is, our econometric model estimates that there is a negative relationship between GDB opex and the percent of gas distribution main that is not constructed of cast iron or bare steel (*i.e.* having a less cast iron and bare-steel intensive gas delivery infrastructure). PEG's model therefore captures an important aspect of capital-opex substitution in the coefficient on the cast iron and bare steel variable. When GDBs reduce the cast iron and bare steel intensiveness of their system, in our model, this substitution effect will be reflected in lower predicted GDB opex and more rapid growth in opex PFP. Because this important capital-opex substitution effect is captured by the cast iron and bare steel variable in PEG's model, it is even less surprising that the capital quantity variable in our model failed to identify another independent, statistically significant effect. This further bolsters confidence that the overall results of PEG's econometric model are reasonable.

It is also worth noting that PEG's estimate of a positive coefficient is consistent with other information that has been presented in the GAAR. For example, in its Gas Access Arrangement Information discussion on "productivity" for opex, SPAusNet states that one reason it believes that PEG's estimate for PFP gains is not reasonable is that "capital expenditure is forecast to rise, making large reductions in the workforce more difficult."[67] This statement clearly runs counter to what Meyrick and standard economic theory would predict. If the capital coefficient on the short run cost model was negative, it would imply that a forecast increase in capital expenditure would lead to opex reductions. At the very least, these arguments would imply that an increase in capital input would make "reductions in the workforce" *less difficult* since it would increase the potential for capital-labor substitution. SPAusNet says exactly the opposite. SPAusNet's statement is in fact more consistent with a positive relationship between opex and capital spending *i.e.* greater capitalization may make it more difficult to reduce certain opex inputs, and hence will be associated with increased opex. This provides further support for the view that the relationship between capital inputs and opex for GDBs is more complex than pure economic theory (which does not necessarily consider the regulatory context and other GDB conditions) would predict.

[67] SPAusNet (2007), p. 27.

3.3.6.6 Firm Specific Opex Targets

Finally, Meyrick claims that "a fundamental principle of incentive regulation is that productivity targets should be set using industry average performance rather than firm specific performance whenever possible."[68] It recommends that a single PFP target be applied to all three GDB since they all face broadly similar conditions, and "any benefits (of tailored PFP forecasts) would be small compared to likely forecast errors and the costs are that potentially perverse incentives are created for the GDBs to alter their current behaviour to influence the future targets that would be set using the same approach in future GAARs."[69]

These opinions are not consistent with either the "principles of incentive regulation" or with the approach that PEG has recommended for the GAAR. Effective incentive regulation simply requires that the data used to set the terms of indexing formulas be "external" to the company in question, not that they be calibrated using industry average rather than firm-specific measures. It is true that for indexing formulas to be "external" to a company they must not be affected by that company's actual behavior when it is subject incentive regulation, and this condition is satisfied by PEG's recommended approach. PEG has generated firm-specific forecasts of PFP trends using econometric methods. None of the GDBs can influence the values for the PFP "drivers" that are estimated by this model. Moreover, the projected changes in the GDBs' business condition variables reflect "exogenous" conditions that are almost entirely beyond management control. PEG's PFP recommendations therefore satisfy the principles for incentive regulation and cannot create the kinds of perverse incentives that Meyrick claims would be the "costs" of such an approach.

It should also be recognized that the issue of whether using firm-specific data to set the terms of indexing formula has been addressed in legal proceedings in Victoria. Clause 5.10 of Victoria's Tariff Order says that "(i)n making any price determination…the Regulator General must…utilize price based regulation adopting a CPI-X approach and not rate of return regulation." In 2001, TXU challenged the electricity price determination that was made by the predecessor to the ESC, saying that

[68] Meyrick (2007a), p. 41.
[69] Meyrick (2007a), pp. 41-42.

its use of firm specific information to set the terms of a price control was not consistent with this Clause. The Supreme Court of Victoria ruled against TXU and concluded that setting the terms of CPI-X formulas using firm-specific data can be consistent with incentive regulation principles.

It should also be noted that Meyrick personnel have advocated company-specific opex targets in regulatory price controls. In a project with PEG, Meyrick personnel and PEG recommended separate opex targets and therefore different "rates of change" in opex for Energex and Ergon in Queensland (although the "rate of change" formula itself was not used). This recommendation was also not based on the fact that there were different operating environments for the companies but, rather, that we concluded there were differences in the companies' management efficiency and therefore different potentials to achieve future efficiency gains. This past recommendation from Meyrick personnel does not seem to be compatible with its current position on what constitutes a "fundamental principle of incentive regulation" (*i.e.* it should use industry average performance rather than firm specific performance to set allowed opex).[70]

3.3.6.7 Conclusion

Meyrick has presented a detailed critique of PEG's econometric model and approach for projecting opex PFP trends for the GDBs. PEG has reconsidered our use of Meyrick's ANZ database for PFP projections and has therefore confined our review of Meyrick's Response to the points it raises about PEG's econometric model and use of US data. PEG has carefully considered Meyrick's critique and concludes that there is no merit to any of the points it raises on these issues. Indeed, Meyrick itself has estimated the same translog cost function form using US GDB data. Meyrick finalized this work on the same day that it presented its rate of change recommendations to the GAAR, not at some point in the distant past.

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[70] For completeness, it should be noted that Meyrick says another "major problem" is PEG's forecast values for the GDB capital quantities. In our original report, these values decreased for Multinet and SPAusNet and increased only modest for Envestra over the term of the GAA. Meyrick (2007a, p. 41) says the "negative forecasts by PEG (2007a) for SPAusNet and Multinet are…at odds with the available evidence on GDB capital inputs." Meyrick (2007a) does not present any specific capital values to support this claim, but the updated capital quantities used for PEG's projections – which come directly from the closing 2007-2012 regulatory asset bases (in real dollars) determined by the ESC for the GAAR – show positive changes for all three distributors, so this criticism from Meyrick now appears to be moot.

PEG therefore retains its US econometric model for projecting opex PFP growth for Victoria's GDBs. We have updated our projections using the most recent data for changes in the relevant business condition variables that the ESC has approved for the GDBs in the GAAR.[71] Changes in these business condition variables are presented in Table Five. The updated PFP projections are presented in Table Six. It can be seen that PFP for the industry is projected to grow at 2.47% per annum. The relevant projections for SPAusNet, Envestra and Multinet are 2.25%, 2.31% and 2.87%, respectively.

3.4 Output Growth and CPI

As we stated in our original report, it is important for the output growth term to be internally consistent with other data that the ESC uses to determine revenue requirements for the GAA and that PEG uses to determine opex PFP trends. The output adjustment used in the rate of change formula should reflect the changes in customer numbers and volumes that are used elsewhere in the GAAR and not necessarily the past changes in these variables that Meyrick used. PEG's report used a forward-looking output growth trend that was internally consistent with our PFP recommendation, while Meyrick's recommended output growth trend was – and remains - backward looking. PEG's approach is therefore more consistent with a best estimate determined on a reasonable basis than Meyrick's and is retained in this report.

However, PEG has updated our output growth adjustment to reflect the fact that we are no longer using the econometric model that was estimated using Meyrick's ANZ dataset, as well as updated information on changes in customer numbers and delivery volumes from the ESC. PEG originally calculated the output growth term as a cost elasticity share-weighted average of projected changes in each GDB's customer numbers and delivery volumes. Our original cost elasticity weights were an average of the weights estimated in the US and ANZ short run cost models. This approach led to an

[71] PEG computed changes in customer numbers, total throughput and percentage of deliveries to residential and commercial customers using ESC data on determinations for these variables for 2007-2012. We computed changes in the miles of distribution main using data from the Meyrick GDB database, and changes in the percent of non-iron and bare steel data using data from Meyrick and the ESC's determinations on changes in low pressure pipe in 2008-2012. Changes in capital quantity were computed as the ESC's allowed changes in the closing value of the RAB, in real terms. Changes in the number of electric customers were based on historical changes for the companies, using PEG's TFP database for Victoria's power distributors.

Table 5

PERCENTAGE CHANGE OF VARIABLES USED IN ECONOMETRIC DECOMPOSITION OF OPEX PFP

Variable	U.S. Sample Average	Envestra Gas Average	Multinet Average	SPAusNet Average
Number of Customers	1.79%	2.76%	1.12%	2.50%
Total Throughput	0.26%	1.04%	0.49%	0.82%
Capital Quantity	1.62%	4.41%	0.18%	1.99%
% Residential & Commercial Throughput	0.00%	0.95%	-0.39%	0.95%
% Non-Iron & Bare Steel Dx Miles	0.61%	1.64%	1.68%	1.44%
Number of Electric Customers	0.47%	0.00%	1.44%	1.79%
Miles of Distribution Main	1.67%	1.87%	0.21%	2.15%

Table 6

ECONOMETRIC DECOMPOSITION OF O&M PFP - GAS DISTRIBUTION

(Australian Companies Assessed with Forecast Data Growth Rates)

	SPSAusNet	Envestra Victoria	Multinet
Technological Change [A]	**1.50%**	**1.50%**	**1.50%**
Returns to Scale [B]	**0.55%**	**0.63%**	**0.34%**
Sum of Output Elasticities	0.73	0.73	0.64
Output Growth	2.07%	2.32%	0.93%
Output Parameters			
Customers	*0.57*	*0.57*	*0.57*
Deliveries	*0.20*	*0.20*	*0.20*
Weight - Customers	74.22%	74.22%	74.22%
Weight - Deliveries	25.78%	25.78%	21.04%
Customer Growth	2.50%	2.76%	1.12%
Delivery Growth	0.82%	1.04%	0.49%
Trend in Business Conditions [C]	**-0.20%**	**-0.19%**	**-1.04%**
Trend			
% Non-Cast Iron & Bare Steel	1.44%	1.64%	1.68%
Electric Customers	1.79%	0.00%	1.44%
% Residential and Commercial	0.95%	0.95%	-0.39%
Capital Quantity	1.99%	4.41%	0.18%
Line Miles	2.15%	1.87%	0.21%
Parameters			
% Non-Cast Iron & Bare Steel	-0.5697	-0.5697	-0.5697
Electric Customers	-0.0149	-0.0149	-0.0149
% Residential and Commercial	0.2492	0.2492	0.2492
Capital Quantity Index	0.0572	0.0572	0.0572
Line Miles	0.1376	0.1376	0.1376
Trend x Parameter			
% Non-Cast Iron & Bare Steel	-0.82%	-0.93%	-0.96%
Electric Customers	-0.03%	0.00%	-0.02%
% Residential and Commercial	0.24%	0.24%	-0.10%
Capital Quantity Index	0.11%	0.25%	0.01%
Line Miles	0.30%	0.26%	0.03%
PFP from the Cost Model [A + B - C]	**2.25%**	**2.31%**	**2.87%**
Weights (Projected Average O&M Cost Shares)	**32.96%**	**34.51%**	**32.53%**
Industry PFP (Weighted Average)	**2.47%**		

output adjustment term for the GDB industry of 1.93% and output adjustments of 2.42%, 2.26% and 1.09% for SPAusNet, Envestra, and Multinet respectively. We have retained this same basic approach but have revised the cost elasticity weights used in these calculations so that they are based only on the cost elasticity estimates from PEG's US short run cost model. This modification leads to an output adjustment term for the GDB industry of 1.79% and output adjustments of 2.07%, 2.32% and 0.93% for SPAusNet, Envestra, and Multinet respectively. As before, PEG recommends using company specific output adjustments since output growth is largely beyond management control and can vary substantially across GDBs.

Similarly, PEG's estimate for CPI inflation is consistent with what the ESC is using for other elements of the GAAR. The P_0 and X factors for the next GAA depend on the ESC's determination of forward-looking revenue requirements for each GDB. To comply with the internal consistency criterion, the same inflation forecast should be used to set real values for all forward-looking costs that enter into a GDB's revenue requirement calculations. In its Draft Decision, an inflation assumption of 3% per annum was implicit in the ESC's calculation of the real, weighted average cost of capital and hence the values for real capital costs established in the GAAR. A 3% CPI inflation estimate to set (real) values for each GDB's operating costs would therefore be consistent with the inflation assumption that the ESC used to set real values for capital costs in the Draft Decision, and PEG's original report used an estimate of 3% for CPI inflation to set the terms of the rate of change formula. The ESC has now revised its projection of CPI inflation to be 2.7%. PEG has updated its CPI inflation assumption accordingly, and an estimate of 2.7% inflation has now been used to set the terms of the rate of change formula.

4. Evaluation of Horton and GDB Submissions

This chapter will evaluate the report written by Horton 4 Consulting (Horton) and some comments put forward in the Amended Access Arrangement Information (AAI) of the GDBs. Most of the GDBs' and Horton's comments echo points that appear in Meyrick, although they make some new claims. PEG will respond first to the Horton report and then to the GDB comments.

4.1 Response to Horton

Horton makes a number of points regarding PEG's analysis of labor input prices (pp. 8-11), the use of ANZ data (pp. 14-15), the sign on the capital stock coefficient in our econometric model (p. 15), cost overshooting (p. 17), and the conclusion that opex PFP growth for gas distributors can be expected to converge to or be bounded by the growth in PFP for the overall economy (pp. 18-19). PEG responded to each of these points in Chapters Two and Three, and these discussions address Horton's points as well.

We wish to emphasize, however, that Horton's remarks display a fundamental misunderstanding of our cost overshooting analysis. For example, we explicitly distinguish between what Horton calls "outperformance" and overshooting; these concepts correspond to the periods between T0 and T1 and T1 and T2, respectively, in Figure One of PEG's original report. Horton's remarks do not appreciate this important distinction. Moreover, PEG is explicitly **not** recommending that there be any "*ex post* removal of the benefit of outperformance," contrary to what Horton appears to believe.[72] It is also not clear whether Horton is aware of the provisions of the Gas Code that pertain to cost sustainability, but these provisions are extremely pertinent both to assessing any overshooting arguments in Victoria and to evaluating PEG's analysis and conclusions.

Horton advances some points about PEG's econometric analysis and recommendations that were not raised by Meyrick, but none of these claims have merit. In fact, Horton's critique is generally undermined by errors in its descriptions of elementary statistical inference and basic productivity concepts. Moreover, it must be noted that Horton's conclusions are not moored to *any* independent empirical analysis

[72] Horton (2007), p. 17.

but, instead, are based entirely on subjective opinion. This subjective approach elevates the issue of Horton's underlying expertise and understanding of PEG's work.

Horton's report contains many statements which are at best highly dubious and sometimes flatly incorrect. Some examples include the following:

- On page 12, Horton says "all forecasting, indeed the inductive method in general, assumes that the future will be like the past." In fact, both Meyrick's and PEG's forecasts of opex PFP growth for the GDBs start from the opposite premise: the GDBs' future opex PFP growth rates will not be like their past PFP growth rates and can be expected to be lower. While we differ on methodology and how much PFP will decelerate during the term of the GAA, there is no disagreement on the basic idea that the past is not necessarily prologue to the future, and appropriate forecasting must take this into account.

  The cryptic reference to the "inductive method in general" also appears nonsensical. Webster's online dictionary defines (Bacon's) inductive method as one which "ascends from the parts to the whole….and which may be strengthened or weakened by subsequent experience and experiment." Induction is thus generally viewed as a "bottom up" approach in which general conclusions are derived from the accretion of diverse facts and experience, which can certainly lead one to form views of the future that differ from what has occurred in the past. Induction contrasts with the "top down" approach of deduction that begins with assumptions and advances through logic to conclusions.

- On page 13, Horton says PEG adopted a "disaggregated approach…(which) looks at the separate elements in the production function that affect PFP." In fact, PEG analyzes a (short run) cost function, not the "elements in the production function." In addition, in describing these elements, Horton describes technical progress by saying "total factor productivity, output per unit of any input, may rise over time as a result of technical progress." While this is true in a long run cost function, a short run cost function for opex can only be used to estimate the components of opex partial factor productivity (PFP), not total factor productivity (TFP). This is one of many instances in which Horton confuses TFP with PFP and does not correctly identify which productivity concept is reflected in the equations it references. As PEG has demonstrated in its analysis of the PFP and TFP experience in North America, these are different concepts and only PFP growth is relevant for the GAAR. Any expert opinion on PFP growth must be grounded in an appropriate identification and analysis of PFP measures, but Horton's report fails to do this repeatedly.

- Also on page 13, in describing the "operating environment" variables in PEG's model, Horton says "this list illustrates some of the problems of moving from a theoretical discussion to a practical application. None of these factors is really separate from the other categories." Whether any variable "is really separate from" and has an independent impact on opex is not a question that can be answered *a priori*. Researchers should look to the data to address this issue, as PEG has done using rigorous econometric methods.

- On page 15, Horton says "the coefficient on the log of wages squared in the US equation is surprising. It implies that the elasticity of costs with respect to wages decreases by three quarters of a percent for every percentage increase in wages." This is not true; the estimated relationship between wages and opex is more complex than Horton realizes, in part because it is also impacted by interaction effects between wages and other variables.

- On page 15, Horton also asserts that "there are always errors in coefficient estimates" in econometric models, which is not true. It is true that there is always uncertainty in coefficient estimates; this should be obvious from the term "estimate." However, this point applies to every econometric analysis that has ever been conducted. Simply recognizing that statistical analysis deals with probabilities rather than certainties is no reason to discount the results of any econometric study. Rather, the credibility and quality of econometric studies should be evaluated using rigorous statistical tools, assessment of the underlying data, and an understanding of the fundamental economic relationships that were examined.

- Footnote 6 on page 15 says “the quoted t statistic is merely a measure of the probability that the coefficient differs from zero.” In fact, the coefficient is what is estimated by the econometric method and is an estimate of the underlying population parameter. The t statistic is a test statistic on the hypothesis that the underlying parameter value is zero.

- On page 16, Horton says “PEG takes the scale variables to be customer numbers and line length.” This is not true. The outputs in PEG’s model are customer numbers and delivery volumes. Moreover, Horton’s discussion of the UK and a “modest scale effect” (p. 17) suggests that Horton believes “line length” (*i.e.* miles of distribution main) is not reflected in our PFP projections, even though it is.

- Also on page 16, Horton says “excluding the scale variable, network length, the only significant factor is that of the change in the proportion of iron and steel pipes. This is estimated to increase productivity growth by up to 0.3% pa.” It is not clear what Tables Horton is referring to, but neither of these statements is true in any of PEG’s econometric models.

PEG does not believe that these are trivial errors. They show that Horton repeatedly fails to understand many basic facts in our report. It also confuses productivity measures that are central to the issues being analyzed. Horton’s discussion of statistical issues is also deeply flawed. PEG’s analysis involves a certain degree of technical complexity, which we believe was warranted given the necessity to obtain rigorous opex PFP projections when past observed trends almost certainly overstate what is achievable over the term of the GAA. PEG welcomes comment on our report, but an informed and constructive critique must be grounded in an understanding of our work and an ability to apply the underlying economic and statistical concepts properly. Unfortunately, much of Horton's report fails to satisfy these standards.

PEG also wishes to address two somewhat larger points that appear in Horton's report. The first is the point about a "dynamic specification" for the cost model (*e.g.* p. 14). Horton claims that our variable cost model must be capable of distinguishing between the short run cost impact, of a temporary change in output between t and t+1, and the permanent difference in levels of outputs among companies. It states that a failure to do so may over-estimate the coefficient on the time trend in our model.

Horton's reference to a "dynamic specification" is vague and does not present a concrete, alternative specification that PEG should consider. This lack of specifics makes it difficult to evaluate Horton's point in detail. However, Horton appears to misunderstand the details of our econometric model. PEG's estimator accounts for both what Horton (erroneously) calls the "short-run cost impact", or the change in output between t and t+1, and "permanent difference in levels." The first such impact is commonly referred to as "within" variations and the latter as "between" variations. PEG's model estimates for each variable are, in fact, weighted averages of the "within" and "between" GLS estimators, with a "group-wise" heteroskedasticity correction to eliminate potential bias in the estimated standard errors.[73] Our estimates therefore capture both of the effects Horton mentions. There is also ample precedent for the basic form of PEG's cost model and estimator in the applied literature.

Horton also presents what it calls an "aggregate" approach for setting the rate of change formula, which Multinet has endorsed and adopted in its October 2007 submission. It writes on p. 18 that its report described PEG's "partial factor productivity being analysed in the disaggregated approach as being unusual. It is a combination of

[73] In PEG's approach, each "group" refers to the time series observations for an individual sample firm. Our heteroskedasticity correction procedure effectively transforms sample data by weighting each data point by the *inverse* of the associated group's standard error of the residual; this standard error is equal to the square root of that group's residual variance. This procedure reduces the weight on larger sample firms, because larger firms are likely to have greater residual variance. PEG's heteroskedasticity correction effectively mitigates concerns regarding the disproportionate impact of large sample observations on the regression results.

inputs that might be expected to have different productivity growths. It is neither total factor productivity nor labour productivity growth, for which relevant comparisons might be found, but an amalgam with no obvious parallel anywhere." Horton then puts forward four possible measures of productivity growth "that can be confused." One of these is what it calls "operating expenditure productivity growth," which is defined as the difference between the rates of growth of output and real operating expenditure (opex deflated by the CPI). It writes that "this last (measure), while not having a clear economic interpretation, is the answer sought by ESC and has sometimes been analysed by regulators, including in UK electricity distribution." Horton also writes that "the growth of operating expenditure productivity in an industry will differ from zero insofar as its TFP growth differs from that in the economy as a whole (which is embodied in the CPI), as the relative price of its inputs changes and as a result of capital substitution." On p. 19, Horton says "there is no reason to expect normal energy distribution TFP growth to differ from that in the economy as a whole" and, accordingly, it believes that if PEG would have "checked the implications of its disaggregated results" against "these aggregate concepts…it would have found it difficult to justify its implicit conclusion of CPI-2 for unit operating costs."

There are fundamental errors both in Horton's description of PEG's "disaggregated approach" and in its preferred "aggregate approach." First, PEG's methodology is **not** "a combination of inputs that might be expected to have different productivity growth rates." PEG's recommendation for PFP growth is not a combination of different inputs (*e.g.* labor and non-labor opex inputs) at all, but rather a quantification of the impact of different business condition variables on opex PFP growth. After these fundamental "drivers" are quantified, they are combined with expected changes in each GDBs' business condition variables to develop a PFP forecast that is tailored to reflect that GDBs' forecast conditions, which are also reflected in other components of the ESC's building block calculations for allowed revenues over the GAAR. Moreover, PEG's PFP measure is not an "amalgam with no obvious parallel." Opex PFP is a well-defined concept that has parallels both elsewhere in the GAAR (*e.g.* the GDBs' historical opex PFP trends computed by Meyrick) and in the ESC's most recent price controls for

Victoria's power distributors, where the "rate of change concept" was introduced and applied in Victoria using an opex PFP measure.

Perhaps because of these concerns, Horton appears to recommend abandoning the rate of change approach used previously in Victoria for an aggregate approach. The cite above suggests that Horton believes this aggregate approach should be implemented using the "operating expenditure productivity growth" concept. The referenced passage also apparently believes this growth trend can be calibrated by assuming that "normal energy distribution TFP growth" will not differ from that of the overall economy.[74]

These recommendations are both methodologically and empirically unsound. It can be demonstrated that Horton's conclusion about operating expenditure productivity growth is untrue: it is not the case that "the growth of operating expenditure productivity in an industry will differ from zero insofar as its TFP growth differs from that in the economy as a whole (which is embodied in the CPI), as the relative price of its inputs changes and as a result of capital substitution." This can be seen by considering the indexing logic presented below. Horton defines its concept of operating expenditure productivity growth (OPG) as follows:

$$Opex\ productivity\ growth\,(OPG) = \%\Delta Y - (\%\Delta Opex - \%\Delta CPI) \qquad [1]$$

The growth rate in an aggregate inflation index for the economy, like CPI, will be equal to the growth rate in input prices for the economy minus the growth in TFP for the economy.[75]

$$\%\Delta CPI = \%\Delta W^{E} - \%\Delta TFP^{E} \qquad [2]$$

Substituting [2] into [1] we have

$$OPG = \%\Delta Y - \left(\%\Delta Opex - \left(\%\Delta W^{E} - \%\Delta TFP^{E}\right)\right) \qquad [3]$$

The indexing logic for the rate of change formula shows that the growth in nominal (not inflation-adjusted) opex will be given by the following

$$\%\Delta Opex = \%\Delta W^{Opex} - \%\Delta PFP^{Opex} + \%\Delta Y \qquad [4]$$

Substituting [4] into [3] we have

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[74] It is difficult to know exactly what Horton recommends in this section, since it does not present firm quantitative or even methodological conclusions one way or the other.

[75] This is a well-known indexing result that has been demonstrated several times in Victoria; for example, see Kaufmann (2004b).

$$OPG = -\left(\Delta W^{Opex} - \%\Delta PFP^{Opex} - \left(\%\Delta W^{E} - \%\Delta TFP^{E}\right)\right) \qquad [5]$$

Simplifying [5] reduces to

$$OPG = \left(\%\Delta PFP^{Opex} - \%\Delta TFP^{E}\right) + \left(\%\Delta W^{E} - \Delta W^{Opex}\right) \qquad [6]$$

It can be seen that Horton's proposed OPG measure has only two components: the differential between opex PFP growth for the industry and economy-wide TFP growth; and the difference between input price growth for the economy and opex input price growth. This contrasts with Horton's statement that "the growth of operating expenditure productivity in an industry will differ from zero insofar as its TFP growth differs from that in the economy as a whole (which is embodied in the CPI), as the relative price of its inputs changes and as a result of capital substitution." It can be seen that there are at least two errors in Horton's statement. First, the industry TFP growth never appears in the growth rate of OPG. Second, there is no "capital substitution" term in OPG.[76] The third term – the relative price of its input changes – may also be in error, although its not clear how Horton is precisely defining or using this term. In any event, Horton's conclusion about the OPG concept it introduces is incorrect.

It is also difficult to see how such a concept would be helpful in the GAAR. Calibrating the measure above still requires information on the GDBs' projected growth in opex PFP and input price inflation. Horton can simplify the disaggregated approach only by *assuming* that there will be no difference between opex PFP for the industry and TFP growth for the economy. The previous chapter presented data showing that this assumption is empirically unjustified on at least two counts. First, industry PFP trends can and do diverge from economy-wide PFP trends. In addition, PFP trends are usually very different from TFP trends for GDBs.

In sum, PEG believes there is no merit in either Horton's critique of our econometric model or in its proposed "aggregate" alternative approach for setting allowed opex growth over the GAA.

[76] Horton may believe that these discrepancies can be resolved because of the relationship between PFP growth, TFP growth and capital substitution, but it certainly presents no mathematical logic linking these concepts, and the precise mathematical relationship between these measures is likely to be complex.

4.2 Response to GDBs

Finally, PEG wishes to address several comments about PEG's work that appear in the GDBs' most recent submissions. Although most of the GDB remarks echo points made by their consultants, the companies have added some inaccurate interpretations and points that should be corrected for the record.

- In the Database section of the Executive Summary section of Envestra's Amendments to AAI , it writes that, "PEG goes on to state that econometric models have proven to be relatively unsuccessful at measuring the effects of such (operating) differences." In fact, PEG has never said this in either our original Report or any other document. There is a high probability that Envestra meant to say "Meyrick" in this section since the sentences above this passage refer to Meyrick's work. But, as we have previously discussed, Meyrick only implies that econometric models have been relatively unsuccessful at controlling for operating differences when it is commenting on PEG's report. Its comparable econometric work in the GAAR carries the title "Cost Comparisons of Multinet and United States Gas Distribution Businesses Allowing for Operating Environment Differences," and this report uses the same translog cost function and much of the same US database as PEG. In this regard, Envestra's statement that it "is particularly concerned by PEG's approach of discrediting information for one particular use but rendering it appropriate for other uses" is better directed towards its own consultants than to PEG.[77]

[77] Envestra's concern here referred to the fact the PEG used Meyrick's ANZ database to estimate an econometric cost model but questioned whether it was appropriate to use this database for benchmarking the GDBs, as Meyrick had done. Envestra's concern is now moot because PEG is no longer relying on Meyrick's ANZ model for its recommendations, but its broader concern of whether PEG "is discrediting information for one particular use but rendering it appropriate for other uses" is not valid in any case. PEG did, in fact, explain why we believed it is potentially appropriate to use the ANZ for one use (estimating the parameters of a cost function) but not another (benchmarking GDB performance) in response to an information request from Meyrick. Envestra could have referenced our response to understand the reasons for this difference although, as a general matter, there is nothing wrong with using information for one use rather than another. Sometimes information is really only suited for one purpose and not another. The real issue is not ruling out a given information source to answer one question when it has already been used to answer another, but whether one party is criticizing another for using the same information source, and the same econometric cost function form, that it has also used in the GAAR.

For the record, Meyrick's query to PEG was the following:

- On page 29 of SPAusNet's GAAR Revision 2008-12, it says PEG's approach to estimating scale effects "is not consistent with Economic theory. One of the criteria upon which PEGy (sic) judge the reasonableness of productivity estimates, the scale effect, is implemented in a linear fashion and this is inconsistent with Economic theory. Economic theory stipulates that scale economies are not linear as they are subject to diminishing returns to scale."

  This statement shows that SPAusNet does not understand PEG's econometric model or how scale economies are reflected in the PFP projections. First, our model does not assume that "scale economies are linear;" our cost function is not

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In its companion report on the Meyrick benchmarking studies, PEG argues that the ANZ database is 'flawed' because it uses, in part, allowed rather than actual costs. Please explain whey PEG then believes it is acceptable to use this database for its econometric estimation of productivity trends.

Below we present our response, which is essentially that benchmarking involves an additional step beyond econometric estimation and it is at this step where the ANZ data flaws become most material. We believe this response effectively addresses Envestra's "concern" but, if it did not, Envestra should have addressed the substantive points we make below rather than implying that PEG was being inconsistent:

The main flaw with using the ANZ data for benchmarking purposes is the asymmetry in the data that are used for estimating the econometric model and for the benchmarking comparison itself. That is, the benchmarking evaluation involves a comparison of the company's actual costs to the costs predicted by the model. When the model is estimated using allowed rather than actual cost, and allowed costs are expected (on average) to be greater than actual cost outcomes, then there is a bias in the benchmarking evaluation. As stated in PEG's evaluation of Meyrick's benchmarking work for Multinet,

> In light of these points, comparing the actual costs of one enterprise with the allowed costs of another is an example of not comparing like with like. This process is more akin to comparing, say, oranges to tangerines than the more common analogy of comparing apples to oranges. There are some obvious similarities between oranges and tangerines, but tangerines can be expected to be smaller on average. If a tangerine is compared to a group of oranges, it would be a mistake to infer that the difference in size was due to the relative inefficiency of the tangerine grower. However, a mistake of this nature is likely when actual utility costs are compared to allowed costs. (footnote reference omitted)

At the same time, the report referenced above also makes it clear that using allowed cost data can create problems with the underlying parameter estimates. We therefore believe that PEG's own econometric estimates using ANZ data are less reliable than those using our US database, and we would not recommend that 100% weight be placed on the ANZ estimates as the basis for regulatory decisions. Nevertheless, our main concern with the use of the ANZ database for benchmarking involves the asymmetry in the data that used for econometric estimation and for the benchmarking comparison itself, and this concern is not relevant when (as in the econometric work used for PEG's PFP projection) Meyrick's ANZ database is used to develop econometric estimates and is not used for benchmarking.

linear, since all variables are expressed as logarithms, but the relationship between outputs and cost in the model is not even log linear since there are squared terms for each output and interaction terms among outputs. These terms introduce non-linearities and allow for decreasing returns to scale, contrary to SPAusNet's claims. Second, the implementation of our econometric model projects PFP growth by combining the appropriate parameters from the estimated cost function with the associated information on the GDBs' operating conditions. The framework and decomposition logic that is used for these projections "is well grounded in economic theory," as Meyrick has acknowledged.

- On page 31 of this same document, in referencing Table 5.1.2.4.1: Opex PFP growth rates in gas and electricity distribution, SPAusNet says PEG has estimated opex PFP growth rates in the USA and Canada of between 0.4% and 0.9% for energy distributors. This is untrue and a distortion of the PFP trends that PEG has put forward in these proceedings, as the statements reproduced in this report and our original report clearly demonstrate.

- Also on page 31, SPAusNet says that PEG recommended opex PFP growth of between 0.4% to 0.9% sometime in 2006, and footnotes page 47 of our July 2007 report to support this claim. However, page 47 from this report simply says that *Meyrick* made such a claim about PEG's work, to which we respond (at the bottom of the same page) "(r)egarding opex PFP trends for US gas distributors, Meyrick's data on this issue are simply not accurate." This further illustrates how Meyrick's distortion of the US TFP and PFP evidence has sown confusion in the GAAR and prompted other misleading and unfounded claims.

- On page 33 of this same document, SPAusNet says "it is not possible to replicate PEG's (econometric) analysis as it is either subjective or non-transparent." It should also be noted that Meyrick has made similar claims regarding econometric analysis in the past, although it has not highlighted this point in its October 2007 Response. These claims are demonstrably untrue. PEG has on several occasions provided data and computer programs (including econometric cost functions similar to those used in the GAAR) to other consultants and Commission Staff, and these parties have replicated our results. We also provided Meyrick with all the data and computer programs used to generate our econometric estimates. Meyrick apparently chose not to run these programs, or it replicated our results but chose not to mention this in its Response. If Meyrick would have run the econometric cost models on the data we provided, it would have undoubtedly obtained the same results as PEG, as other parties have in the past.

PEG's previous experience in Victoria also shows that it is possible to replicate the econometric work of other consultants. In the 2005 Electricity Distribution Price Review, PEG was asked to review some empirical work that purportedly estimated different "betas" in CAPM for rural and urban distributors. This work was undertaken by two researchers at Monash University, using a fairly complex Bayesian technique. PEG asked these researchers to provide their computer code and the data used in their analysis. After obtaining this information, PEG attempted to replicate these researchers' results and was able to do so, as we stated in our report. [78]

- On page 30, SPAusNet says "the use of external supporting evidence is one of the key strengths in Meyrick's work which provides confidence in allowing its use for this critical review." However, the "external" evidence that Meyrick uses to support its opex PFP recommendation is either demonstrably inaccurate (US PFP trends), historically inconsistent with the GDBs' opex PFP experience (the BIS Shrapnel projections), or based on an aggregation of industries that have no relevance to the GAAR or the GDBs' prospective PFP growth (the ABS data). Moreover, regulatory precedents for electricity distribution are not relevant for gas distributors since cost pressures in fact differ considerably across the industries (*e.g.* smart meters and distributed generation will impact electric distributors' cost structures much more prominently than gas distributors; the

[78] Kaufmann and Kalfayan (2005), p. 19.

replacement of cast iron and bare steel main is also officially encouraged in Victoria and other jurisdictions, and these capital replacement expenditures lead to significant opex savings and thus enhanced opex PFP growth for GDBs but not for electric DBs). Review of the external evidence presented by Meyrick therefore does not lead to confidence in its opex PFP recommendation. Indeed, this examination actually demonstrates there is no foundation for Meyrick's recommendation.

In contrast, PEG's recommendation of 2.47% opex PFP growth is broadly consistent with a range of external evidence. PEG has submitted TFP (and associated PFP) studies in regulatory proceedings that have been subject to extensive analysis and outside critique. These reviews have led regulators to rely on PEG's proposed TFP trends for approved regulatory plans. In the PEG studies that Meyrick cites, our results show that opex PFP is growing by about 2.4% per annum for US GDBs. This estimate is bolstered by official data from the US government (*i.e.* the US Bureau of Labor Statistics), which show labor productivity for US GDBs growing by more than 3% per annum, which is more than twice the recent trend for US electric utilities. And while PEG again reiterates its concerns about using power distributors' experience for gas distribution, if SPAusNet and the other GDBs wish to rely on the experience of Victoria's power distribution industry, the most recent evidence shows that its opex PFP has grown by an average of 3% per annum between 1998 and 2006.[79] This period excludes the 1995-98 burst of PFP gains that was achieved immediately after privatization. Thus, if we accept SPAusNet's opinion that "the use of external supporting evidence is one of the key strengths" supporting a given recommendation for opex PFP growth, then this criterion strengthens PEG's recommendation but not Meyrick's.

[79] Kaufmann, L. and D. Hovde (2008), "TFP Research for Victoria's Power Distribution Industry: 2006 Update," Report prepared for the Essential Services Commission.

Finally, the *internal* opex PFP experience of the GDBs is also worth noting. Meyrick's own data on the GDBs PFP shows the following growth trends:

Period	Trend Growth Rate
1998-2006	6.41%
2002-2006	7.14%
2004-2006	10.4%

These data show that the GDBs's PFP growth has accelerated over time, and the companies are *currently* experiencing PFP growth of over 10% per annum. PEG's opex PFP forecast therefore reflects a 75% deceleration in PFP growth from current trends, which is a very considerable slowdown.

5. Conclusion

Based on our original analysis and the foregoing review of new information presented in the GAAR, PEG recommends the following parameter values for the rate of change formula for the Victorian gas distribution industry:

- Labor price inflation 5.7%
- Inflation in the prices of non-labor opex inputs 2.6%
- Cost shares for labor and non-labor inputs in opex 62%/38%
- The growth in GDB output 1.79%
- The rate of growth in opex PFP 2.47%
- The growth in CPI inflation 2.7%

We believe these recommended values are best estimates determined on a reasonable basis, as required by the Gas Code and as further elaborated in our original report. Our recommendations have been updated to reflect the impact of all new, objective and accurate information that has either come to light since our original report or has been submitted in response to our report. Based on this information, PEG has changed the recommended growth in labor price inflation to 5.7%, adjusted the rate of growth in industry PFP to 2.47%, and modified the growth in GDB output to be 1.79%. We have also revised our CPI inflation forecast to be consistent with what the ESC is using in the rest of the GAAR. When these values are substituted into the rate of change formula, the change in real opex over the term of the GAA for the industry as a whole is calculated as:

$$\Delta Real\,\text{Opex} = (.62*5.7+.38*2.6) - 2.47\% + 1.79\% - 2.7\% = 1.14\% \qquad [9]$$

Thus, PEG believes the best estimates of the rate of change parameters lead to a 1.14% annual change in the industry's real opex over the term of the GAA. This compares with our original recommendation of -.05%, Meyrick's original recommendation of 2.66%, and Meyrick's updated recommendation of 3.46%. The main reason for the upward revision in PEG's recommendation was the new information presented on the labor price inflation parameter.

It is also appropriate for the rate of change formulas that apply for an individual GDB to reflect the output growth trend and PFP projection specific to that company, since both can be affected by factors that are largely beyond managerial control. The company specific PFP projections and output quantity trends were presented at the end of Chapter Three. Bringing this information together implies the company-specific rate of change formulas that are summarized below on Table Seven.

Table 7

Rate Of Change Recommendations
Individual GDBs

	SPSAusNet	Envestra Victoria	Multinet
Labor Price [A]	5.70%	5.70%	5.70%
Labor Share [B]	0.62	0.62	0.62
Non-labor Price [C]	2.6%	2.6%	2.6%
O&M Input Price [D] = [B * A + (1 - B) * C]	4.52%	4.52%	4.52%
PFP [E]	2.25%	2.31%	2.87%
Output [F]	2.07%	2.32%	0.93%
CPI [G]	2.70%	2.70%	2.70%
Rate of Change [H] = [D - E + F - G]	**1.64%**	**1.83%**	**-0.12%**

Appendix: Cost Overshooting

PEG's report contains a discussion of cost sustainability and the implications for allowed opex if a GDB "overshoots" sustainable costs because of excessive cost cutting. Recall that the Gas Code says non-capital costs should not be recovered if those costs "would not be incurred by a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the Reference Service." Meyrick's response makes several points regarding PEG's analysis of these issues, as summarized in the following passage:

> PEG (2007a) contains a lengthy discussion of a notion of 'cost overshooting' and posits that if cost reductions have 'overshot' then there will be a period of ensuing lower, or even negative, productivity growth until the firm returns to a sustainable position. This discussion appears to have emanated from taking a statement made in Meyrick (2007a) out of context. In our response to an information request from PEG in May 2007, we indicated that there was no evidence that this has occurred in the case of the GDBs and we were not implying that it had. But this has not been acknowledged by PEG (2007a) which uses the quote out of context in support of its notion. We have further requested PEG to provide any evidence it has that cost 'overshooting' has occurred in our information request dated 4 September 2007 but the PEG response of 18 September 2007 did not answer this question.[80]

This paragraph contains a number of distortions. First, there is no question about where the notion of cost overshooting "emanated" from in the GAAR – the hypothesis was first advanced by Meyrick (2007b, p. 9). BIS Shrapnel also presented a very similar concept, but did not use this exact term, in its work on behalf of the GDBs. Cost overshooting is therefore not our notion but Meyrick's and, to a lesser extent, BIS Shrapnel's.

PEG has also been very careful to consider and accurately portray the cost overshooting issue in the full context in which these ideas were first presented and subsequently elaborated, as well as the broader context of all the empirical evidence presented in the GAAR. PEG's first reference to this issue, on page 14 of our report, is reproduced below:

[80] Meyrick and Associates (2007a), *op cit*, p. 5.

The issue of cost sustainability arises in both the Meyrick and BIS Shrapnel reports. For example, Meyrick says that "initial periods of intense cost cutting can **often** 'overshoot' the longer term sustainable level of input use. This is because the new owners are not fully familiar with the business and may be responding to short term incentives to maximise profits rather than to provide a reliable, high quality service in the longer term" (emphasis added).[81] Relatedly, BIS claims that "the (electric, gas and water sector's) significant labour shedding – which drove the productivity gains in the 1987 to 2000 period – was **probably overdone**, as suggested by the solid growth in employment despite low output growth since 2000/01, and a reversal of the previous productivity gains." (emphasis added)[82] Both GDB consultants therefore claim that a significant portion of utilities' achieved opex PFP gains may stem from non-sustainable cost reductions.

As this passage makes clear, the issue of cost overshooting was introduced by the GDBs' consultants in the GAAR. While Meyrick does not say overshooting has necessarily occurred for the GDBs, it does say that this occurs "often" during "initial periods of intense cost cutting," and the years following the GDBs privatization certainly qualify as such a period. BIS also states that the significant cuts in electric, gas and water labor costs were "probably" excessive. PEG believes it is very relevant that the "overshooting" issue was raised in two separate consultant reports that were used to support the GDBs' rate of change formula. We were asked to review the Meyrick and BIS reports, and our review would have been incomplete if we did not consider the implications of the cost 'overshooting' phenomenon that both firms raised, particularly since this issue pertains directly to the cost sustainability provisions of the Gas Code. PEG also invites all interested parties to review the relevant Meyrick and BIS reports, which will confirm that no relevant context has been omitted from PEG's references to the consultant reports.[83]

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[81] Meyrick and Associates (2007b), *op cit*, p.9.

[82] BIS Shrapnel (2007a), "Outlook for Wages to 2012/13: Electricity, Gas and Water Sector – Australia and Victoria," p. 28.

[83] For completeness, it should be noted Meyrick (2007a) has one additional sentence, following the quote in Kaufmann (2007b), in the paragraph where it introduces the notion of cost overshooting and says that it often occurs in utility industries. This sentence reads "This (cost overshooting) may also result from privatisation occurring at a time of surplus capacity in the industry and, as that capacity is fully utilized or as assets near the end of their useful lives, input use will have to increase to allow higher levels of maintenance and asset refurbishment." In its May 2007 response to our data request, Meyrick added that

In its Response, Meyrick argues that when it said that cost overshooting often occurs, it "was making the point that high productivity growth rates immediately following periods of reform do not provide a good guide to sustainable future productivity growth rates."[84] But this point is clear and has never been disputed by PEG.[85] Moreover, if Meyrick wanted to make this simple point, there was no need to introduce the "overshooting" concept. Such overshooting differs in nature from the one-time elimination of productive inefficiencies that give rise to the "high productivity growth rates immediately following periods of reform" that exceed sustainable productivity growth rates.

These differences are apparent in Figure One on page 16 of our report. The interval of time between T0 and T1 refers to the period "immediately following reform" and the associated elimination of productive efficiencies. This period does **not** include any cost overshooting. This overshooting period takes place only between periods T1 and T2. The critical difference between these periods is that overshooting, by definition, pushes costs below what are sustainable on an ongoing basis. The company's behavior during the T1 and T2 interval therefore does not comply with Section 8.37 of the Gas

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this issue has been recognized by a number of Australian regulators, most notably IPART's 2004 electricity distribution decision.

However, PEG concluded that Meyrick's point about "surplus capacity" was not relevant for the issue of sustainable opex, so the fact that this single sentence was not reproduced in our report does not omit any meaningful context from the discussion. "Surplus capacity" is superfluous to the issue at hand for at least three separate reasons. First, if "surplus capacity" exists, it pertains to capital inputs, not operating inputs. Increased capacity utilization could therefore directly affect the need for new capital spending but not for operating expenditures, which was the focus of our review. Second, no evidence has been presented that surplus capacity in fact existed in Victoria's gas distribution industry; Meyrick's point is therefore conjecture and not fact. Third, the relationship between greater capacity utilization and maintenance spending is very different between the electric and gas distribution industries; this is another example of why analysts should not draw spurious inferences on gas distributor opex from electricity distributors' experience.

[84] Meyrick (2007a), p. 24.

[85] This same basic point, that the elimination of one-time inefficiencies after privatization can lead PFP gains to be greater than their long-run sustainable levels, is identical to what Meyrick calls "the convergence effect" and which it also says that PEG does not acknowledge (Meyrick 2007a, p. 27). This point is manifestly untrue; Figure One on p. 16, and the discussion on pp. 13-18, clearly shows that PFP growth is greater in the period from T0 to T1, when productive efficiencies are eliminated, which is the period for Meyrick's "convergence effect." It should also be noted that Meyrick continues to misstate the true nature of "the convergence effect," which does not imply that PFP growth will be constrained by the rate of technological change over time. PEG discussed this issue on pp. 19-22 of our report. This analysis shows that it is logically impossible to support the PFP decomposition equation that Meyrick says is "well grounded in economic theory" and Meyrick's interpretation of the "convergence effect….whereby productivity growth becomes constrained by the rate of technological change in the industry once all identifiable inefficiencies are removed."

Code, since cost cutting activity that pushes opex below its sustainable level is not consistent with the actions of a "prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, to achieve the lowest sustainable cost of delivering the Reference Service." As PEG's analysis also makes clear, any time cost overshooting has occurred, a firm's own PFP growth will necessarily be below the long-run sustainable trend until all excessive cost cuts have been reversed.

PEG believes that neither Meyrick nor BIS realized the implications of cost overshooting when they introduced the concept. PEG has not "ignored" Meyrick's point regarding cost overshooting but, rather, we have analyzed the issue and considered its implications in greater depth. Our analysis clearly takes Meyrick's argument into account but demonstrates that cost overshooting is distinct from a one-time elimination of productive inefficiencies that raises productivity trends above sustainable levels (which is, again, a straightforward point that PEG has already acknowledged in several Victorian reports). PEG's analysis also shows that overshooting necessarily causes future PFP growth to be *below* sustainable levels, at least until all excessive cost cuts have been reversed. This finding is new and has not previously been raised in Victoria, but Meyrick's Response *has* chosen to ignore this point and our analysis in its entirety. This is unfortunate, because an objective analyst should consider whether firms that – in Meyrick's words - "may be responding to short term incentives to maximise profits rather than to provide a reliable, high quality service in the longer term" are complying with the Code's requirements to be a "prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the Reference Service." PEG believes that our analysis demonstrates that this cannot be the case. This is an important conclusion that is directly relevant to the GAAR, and it stands unrebutted – indeed, it is unaddressed - by either Meyrick or BIS.

In addition, PEG's report contains a detailed assessment (pp. 41-43) of whether "cost overshooting" has in fact taken place by Victoria's GDBs. This analysis was prompted by the fact that, in Meyrick's PFP study, the PFP growth for the GDBs *accelerated* (*i.e.* increased at a more rapid rate) in the last four sample years (2002-2006) compared to the first four sample years (1998-2002). This is a very curious and unexpected result, since one might expect an initial "burst" of PFP gains immediately after privatization which will moderate as initial cost inefficiencies are eliminated. Meyrick's PFP work shows that the *opposite* has occurred for the GDBs, and PFP for these companies has grown more rapidly in each of the two most recent years (2005-06) than in any other year but one since privatization.[86] PEG considered four possible hypotheses to explain this pattern of PFP growth. We rejected the first three as being implausible. The fourth hypothesis was that cost "overshooting" contributed to the more rapid PFP gains in 2002-06. On this point we wrote that

> PEG is very reluctant to conclude this, partly because "overshooting" is nearly impossible to demonstrate definitively. Nevertheless, we believe this is the most plausible explanation for the pattern of the GDBs' opex PFP gains and must conclude that there is a significant probability that such overshooting has occurred. The power distributors registered a cumulative 24.8% decline in opex input after eight years of industry privatization, all of which occurred during the first four years. The GDBs recorded a cumulative 29.6% decline in opex input in eight years, with real opex reductions accelerating in later years, including cuts of 10.1% and 6.1% in the last two sample years (2005-06). It is also noteworthy that BIS Shrapnel and Meyrick each support the notion that "overshooting" occurs often (or has probably already occurred) in utility industries after privatization or corporatization. If we accept the BIS and Meyrick conclusions of frequent or likely cost overshooting in utility industries, PEG believes the magnitude and pattern of opex PFP gains for the GDBs would be more consistent with this phenomenon than what the ESC has observed for Victoria's power distributors.[87]

Meyrick never addresses PEG's analysis regarding possible overshooting for the GDBs. Less innocuously, Meyrick's Response deliberately distorts the evidence on this point. In the passage that was previously quoted, Meyrick says that "(w)e have further requested PEG to provide any evidence it has that cost 'overshooting' has occurred in our information request dated 4 September 2007 but the PEG response of 18 September did not answer this question." PEG is at a loss for explaining why Meyrick would make a statement that is clearly and verifiably untrue. Below we present Meyrick's September 4 request on this issue, and PEG's September 18 response, both in their entirety.

> **Meyrick:** Please provide a detailed explanation of the objective, quantitative basis on which you conclude that that (sic) 'there is a significant probability that

[86] The Victorian GDBs' PFP grew by 12.02% in 2005 and 8.87% in 2006; these are the first and third most rapid growth rates since 1998. The second most rapid PFP growth was 10.82% in 1999.

[87] Kaufmann (2007a), *op cit*, p. 43.

> cost overshooting has occurred in Victoria's gas distribution industry.' Note that Meyrick did not say that some degree of 'overshooting' has necessarily occurred in the Victorian gas distribution industry.
>
> **PEG:** This conclusion is explained in detail on pp. 41-43 of the referenced report; the conclusion also draws on a more general analysis of the overshooting issue presented on pp. 13-18 of the referenced report.

It is clear from this exchange that PEG is directing Meyrick to the "detailed explanation" that was already provided in our original report. This explanation is also objective and linked directly to the quantitative evidence on PFP growth developed by Meyrick. In our opinion, the phrasing in Meyrick's Response report ('provide *any* evidence') does not really convey the nature of its original request ('provide a detailed explanation of the objective, quantitative basis'). More importantly, Meyrick's Response materially misrepresents our response and attempts to deny the reality of something which quite clearly exists. This is again unfortunate, because it could have been illuminating for Meyrick to address the new and substantive points in PEG's analysis of cost overshooting rather than ignoring them. [88]

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[88] Meyrick's discussion of cost overshooting also contains other distortions. For example, far from what the quoted passage in Meyrick (2007a) claims, its May 2007 response never says "that there was no evidence that this (overshooting) has occurred in the case of the GDBs and we were not implying that it had." In fact, Meyrick discusses overshooting two times in that response. In the first instance, it says "(w)e make a secondary argument that new ownership may take some time to become fully familiar with the characteristics of the business and so there *may* be some 'overshooting' during initial cost cutting." The second time, Meyrick says "(i)n case PEG is in any doubt, we are not saying that current forecasts indicate some degree of 'overshooting' has *necessarily* occurred in the Victorian gas distribution industry" (emphasis added in both instances). Thus in May 2007, Meyrick qualified its original position that overshooting occurs 'often' in utility industries to one where there "may be some overshooting" but they are not saying that "overshooting has necessarily occurred." This falls well short of saying there is 'no evidence that this (overshooting) had occurred,' so it's not surprising that PEG did not "acknowledge" this conclusion since Meyrick did not advance it until October 2007. Moreover, PEG's July 2007 report did cite and consider the points made in Meyrick's May 2007 response to our data request. Meyrick could have chosen to dispute our analysis but, having passed on that opportunity, it cannot now credibly claim that we did not consider all the information that Meyrick presented to us on this issue.

Credentials

Pacific Economics Group LLC (PEG) is one of the world's leading economic consultants on the econometric, input price and productivity measurement issues that are critical for establishing an appropriate rate of change formula for gas distributors' operating expenditures (opex). In Victoria, PEG developed the first estimates of total factor productivity (TFP) and partial factor productivity (PFP) trends for Victoria's power distribution industry. This work was done in parallel with the 2006-2010 Electricity Distribution Price Review (EDPR), and our TFP and PFP estimates have since been updated twice to include two new years of data. During the EDPR, PEG also evaluated the reasonableness of a study commissioned by the electric distribution businesses that projected labor price trends for the power distribution industry. Our TFP work also developed an estimate of the share of opex associated with labor costs, which the ESC subsequently adopted in its final decision.

In addition, PEG is the leading consultant on productivity and benchmarking research for energy utilities and regulators in North America. We have testified more than two dozen times in support of productivity trends that we estimated for North American gas and electric utilities. PEG has also undertaken productivity and benchmarking research for clients in Europe, Asia, the Caribbean, and South America. In total, PEG has been involved in more than 100 performance-based regulation projects and has undertaken benchmarking analyses for more than 60 energy utility or regulator clients throughout the world. Meyrick references a considerable amount of PEG's productivity work, both in Australia and North America, in the analysis that they undertook to develop recommendations on the opex rate of change formula.

Dr. Lawrence Kaufmann is a Partner in the Madison office of PEG. His primary responsibilities include developing and undertaking supporting empirical research on performance-based regulation (PBR) and competitive market reforms for energy utilities. He has worked with many leading utilities in North America on these issues. His specialties include statistical benchmarking, estimating TFP, PBR plan design and incentive regulation theory. He is also a specialist on service quality issues. Dr. Kaufmann has testified 29 times on PBR, benchmarking and related issues. He was also the chief advisor to the Ontario Energy Board (OEB) on PBR issues during the Natural Gas Forum undertaken by the OEB in 2004-05 and is currently advising the OEB on the development of Third Generation Incentive Regulation Mechanisms for electricity distributors in Ontario.

In addition to his work in North America, Dr. Kaufmann has been active in regulation overseas for a decade. He has advised regulators and energy utilities in Mexico, Bolivia, Argentina, Japan, New Zealand, Jamaica, Curacao and the UK. He has also been particularly active in Australia, where he has worked for most of Australia's major energy utilities and several regulatory agencies. Dr. Kaufmann was recently the head of an international consulting consortium for the Bundesnetzagentur (BNetzA), the recently-created energy network regulator in Germany. Dr. Kaufmann advised the BNetzA on international developments in incentive regulation and incorporating the lessons from this experience in Germany's newly-established energy regulation framework.

Dr. Kaufmann is the author or co-author of over twenty publications, including several White Papers on PBR and code of conduct issues for the Edison Electric Institute. Before joining PEG, he was a Senior Economist at Christensen Associates. He holds a Ph.D. in Economics from the University of Wisconsin. A copy of Dr. Kaufmann's full CV is available on request.

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